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BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF WYOMING

IN THE MATTER OF THE APPLICATION
OF ROCKY MOUNTAIN POWER FOR DOCKET NO.
AUTHORITY TO INCREASE ITS RETAIL 20000-633-ER-23
ELECTRIC SERVICE RATES BY (RECORD NO. 17252)
APPROXIMATELY \$140.2 MILLION PER
YEAR OR 21.6 PERCENT AND TO REVISE VOLUME V
THE ENERGY COST ADJUSTMENT MECHANISM

TRANSCRIPT OF HEARING PROCEEDINGS

PURSUANT TO NOTICE duly given to all parties in
interest, this matter came on for hearing on the 31st day
of October, 2023, at the hour of 8:30 a.m., in the
Commission Hearing Room, 2515 Warren Avenue, Suite 300,
Cheyenne, Wyoming, before the Public Service Commission,
Ivan H. Williams, Counsel, presiding, with Chairman Mary
Throne, Deputy Chairman Chris Petrie and Commissioner
Michael Robinson also in attendance. Also present Wesley
Neuman, Counsel, Luy Luong, Michelle Bohanan, Nathan
Brennan, Kelli Kolkman, Nathan Petrisin, Kelly Hunt, Melisa
Mizel, Andrea Mitchell and Allyson Brackett, technical
advisors to the Commission.

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	I N D E X	
		PAGE
1		
2		
3	ROCKY MOUNTAIN POWER WITNESSES:	
4	NICHOLAS HIGHSMITH (continued)	
	Examination by Mr. Luong	879
5	Examination by Mr. Brennan	885
	Examination by Mr. Williams	895
6	Examination by Chairman Throne	896
	Redirect Examination by Mr. Kumar	900
7	Recross-Examination by Mr. Nelson	904
	Further Redirect Examination by Mr. Kumar	905
8		
9	WIEC WITNESSES:	
10	BRADLEY G. MULLINS	
	Direct Examination by Mr. Nelson	906
11	Cross-Examination by Mr. Lowney	931
	Cross-Examination Resumed by Mr. Lowney	959
12	Examination by Mr. Petrisin	980
	Examination by Deputy Chairman Petrie	981
13	Examination by Chairman Throne	984
	Redirect Examination by Mr. Nelson	991
14		
	DAVID J. GARRETT	
15	Direct Examination by Ms. King	997
	Cross-Examination by Mr. Lowney	1002
16	Examination by Ms. Brackett	1021
	Examination by Mr. Brennan	1027
17	Redirect Examination by Ms. King	1035
18		
19	PUBLIC COMMENT:	
	STEVE DEGENFELDER	954
20		
21	SIERRA CLUB WITNESS:	
22	RONALD J. BINZ	
	Direct Examination by Ms. Monahan	1038
23	Cross-Examination by Mr. Jensen	1045
	Cross-Examination by Senator Case	1060
24	Examination by Commissioner Robinson	1067
	Examination by Deputy Chairman Petrie	1071
25		

	E X H I B I T S	
1		
2		RECEIVED
3	WIEC Exhibit No. 212.3	909
4	WIEC Exhibit No. 212.4	910
5	WIEC Exhibit No. 241	917
6		
7		
8		
9		
10		
11		
12		
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1 MR. KUMAR: Yes.

2 MR. WILLIAMS: Okay. And so now we will
3 hear from WIEC witnesses?

4 MR. NELSON: That's correct. WIEC would
5 call as its first witness Mr. Brad Mullins.

6 MR. WILLIAMS: Good morning, Mr. Mullins.

7 THE WITNESS: Good morning.

8 MR. WILLIAMS: Will you please raise your
9 right hand.

10 (Witness sworn.)

11 MR. WILLIAMS: Mr. Nelson, you may proceed.

12 MR. NELSON: Thank you. Sorry, I'm less
13 prepared than Mr. Mullins.

14 BRADLEY G. MULLINS,
15 called for examination by Wyoming Industrial Energy
16 Consumers, being first duly sworn, on his oath testified as
17 follows:

18 DIRECT EXAMINATION

19 Q. (BY MR. NELSON) All right. Good morning,
20 Mr. Mullins.

21 A. Good morning.

22 Q. First a logistical note. I don't think that
23 you've been coached necessarily, but if during the course
24 of your examination and cross-examination attorneys or the
25 Commission ask you to refer to exhibits, you can pull them

1 up on the computer screen there. Do you see that in front
2 of you?

3 A. I do see that, and it looks fairly
4 straightforward. So I should manage. Thank you.

5 Q. Would you please state and spell your name for
6 the record.

7 A. My name is Brad Mullins, spelled B-r-a-d
8 M-u-l-l-i-n-s.

9 Q. And, Mr. Mullins, by whom are you employed and in
10 what capacity?

11 A. I'm employed by MW Analytics, a consulting firm
12 that represents customers around the West, and I am the
13 principal of that.

14 Q. And on whose behalf are you testifying today?

15 A. The Wyoming Industrial Energy Consumers.

16 Q. Have you caused to be prefiled in this case
17 direct testimony and exhibits?

18 A. I have.

19 Q. And was that direct testimony and exhibits
20 prepared under your direction and supervision?

21 A. It was.

22 Q. Okay. Starting with your -- the text of your
23 direct testimony, do you have any corrections that you want
24 to make to that testimony at this time?

25 A. I do have one typo to correct. On page 34 of

1 that testimony, on lines 9 and 13, I refer to Account
2 447-Fuel, and that should have been FERC Account 547-Fuel.

3 Q. Thank you.

4 In that the course of reviewing the rebuttal
5 testimony provided by PacifiCorp, is it true that you've
6 also come to make some modifications to the recommendations
7 that you are making to the Commission in this proceeding?

8 A. Correct.

9 Q. If I could ask you to please pull up Exhibit
10 Number 212.3.

11 A. Okay. I have it.

12 Q. Okay. Can you please explain to the Commission
13 what is being depicted in this exhibit.

14 A. All right. So this depicts the latest revenue
15 requirement forecast that I prepared based on adjustments
16 and changes presented in RMP's rebuttal testimony that I
17 found to be reasonable.

18 MR. NELSON: Okay. Mr. Williams, I'd move
19 for the admission of 212.3.

20 MR. WILLIAMS: Mr. Kumar, do you have an
21 objection?

22 Mr. Lowney, I apologize.

23 MR. LONEY: No worries. The Company has
24 no objection.

25 MR. WILLIAMS: Miss Monahan.

1 MS. MONAHAN: No objections.
2 MR. WILLIAMS: Miss Hamilton.
3 MS. HAMILTON: No objections.
4 MR. WILLIAMS: Mr. Phetteplace, do either
5 Senator Case or Mr. Flege have a hand raised?
6 MR. PHETTEPLACE: No hands raised.
7 MR. WILLIAMS: That exhibit is received
8 into the record, thank you.
9 (WIEC Exhibit No. 212.3
10 received into evidence.)
11 Q. (BY MR. NELSON) Okay. Can you please now take a
12 look at Exhibit 212.4.
13 A. Okay. I have that.
14 Q. And can you describe what that exhibit is,
15 please.
16 A. That is the net power cost study supporting my
17 recommended level of net power costs.
18 MR. NELSON: Okay. I would move for the
19 admission of Exhibit 212.4.
20 MR. WILLIAMS: Mr. Lowney, any objection?
21 MR. LONEY: No objection.
22 MR. WILLIAMS: Miss Monahan.
23 MS. MONAHAN: No objection.
24 MR. WILLIAMS: Miss Hamilton.
25 MS. HAMILTON: No objections.

1 MR. WILLIAMS: Mr. Phetteplace, may I just
2 impose upon you to tell me as we proceed if either Senator
3 Case or Mr. Flege raise their hand.

4 MR. PHETTEPLACE: I will do that.

5 MR. WILLIAMS: Thank you. That exhibit is
6 received into the record as well.

7 (WIEC Exhibit No. 212.4
8 received into evidence.)

9 MR. NELSON: Great.

10 Q. (BY MR. NELSON) Mr. Mullins, have you prepared a
11 summary of your testimony for the Commission?

12 A. I have.

13 Q. Given the fact that you cover a wide variety of
14 different topics, I'm going to sort of talk to you through
15 your summary in different piece parts.

16 So to start us with, if you could please just
17 describe generally the examination that you did in this
18 case regarding net power costs and the Aurora model.

19 A. Great. Good morning, Commissioner Robinson,
20 Deputy Chair Petrie and Chairman Throne. I appreciate the
21 opportunity to be here today to testify on behalf of the
22 Wyoming Industrial Energy Consumers. I sponsored testimony
23 in this proceeding on issues surrounding the 2024 forecast
24 of net power costs, or NPC, as well as a few discrete
25 revenue requirement issues. I'll briefly walk through

1 these issues discussing NPC first.

2 So in this case Rocky Mountain Power, or RMP, is
3 requesting a 24.34 percent rate increase. An increase of
4 this magnitude is going to have major implications for both
5 businesses, individuals and families in the state. This is
6 an important case, and as we have seen, most of the
7 requested increase is being driven by NPC.

8 The current level of base NPC included in rates
9 today from the 2020 GRC is \$1.431 billion on a total-
10 Company basis. At that time we were told that the \$3.2
11 billion investment in EnergyVision 2020, which included
12 over 1,000 megawatts of new Wyoming wind resources,
13 repowering of the existing wind fleet and the associated
14 Gateway transmission investment, was going to materially
15 reduce NPC. For one reason or another, however, that
16 reduction never occurred.

17 Since then, actual NPC has increased to
18 approximately \$2.040 billion in 2022. In its rebuttal, RMP
19 is requesting that the Commission approve an even higher
20 NPC baseline of 2.518 billion -- sorry, excuse me, \$2.518
21 billion, which equates to a Wyoming-allocated NPC of \$354.8
22 million.

23 I have reviewed RMP's forecast, and based on my
24 analysis, I am forecasting a major increase to NPC relative
25 to both the 2020 GRC and 2022 actuals. As detailed in

1 Exhibits 2. -- 212.3 and 212.4, my forecast supports an NPC
2 of 2.166 billion or \$307.1 million Wyoming allocated.

3 So notable in this case is the use of a new model
4 called Aurora. And that compares to the former model that
5 was used called GRID. Given the use of a new model, it is
6 expected that there will be challenges and issues to work
7 through.

8 I have been using the Aurora model since 2014 for
9 other utilities, and to be clear, Aurora is a great model.
10 It is important to note, however, that Aurora is different
11 than GRID. It is primarily a power market model, and it
12 was not designed specifically to simulate single-issue or
13 single-utility closed system dispatch in the same way as
14 the GRID model was. To its credit, however, RMP has
15 developed several modeling techniques and work grounds to
16 get the Aurora model to behave similar to the GRID model.

17 I'm not aware of any other utility in the West
18 that uses Aurora with these same techniques. And while I
19 think RMP has generally done a good job developing this
20 model, there remain issues with some of these techniques.

21 Q. Can you please take a moment and describe for the
22 Commission the specific issues that you continue to see
23 going forward with how the Aurora model is implemented in
24 this case.

25 A. Certainly. So before discussing items of

1 disagreement, I will touch on the items that are not at
2 issue. In rebuttal, RMP acknowledged WIEC's testimony that
3 the Ozone Transport Rules will not apply to Utah or Wyoming
4 in the test period. Relative to the July Update, this
5 reduced NPC by 22 million total-Company or 3.2 million
6 Wyoming-allocated.

7 Following my direct testimony, I contacted Energy
8 Exemplar, the maker of the Aurora model, to obtain a
9 backdated version of the Aurora model and confirmed that
10 the minor differences between the NPC run on my computer
11 and the NPC calculated in the July Update were attributable
12 to the model update version, not differences in computer
13 architecture.

14 After reviewing RMP's rebuttal testimony, I also
15 found it reasonable to accept the use of the Commission-
16 approved market cap method for nonliquid markets rather
17 than the 95th percentile approach that I had recommended.

18 And finally, following my direct testimony, I was
19 able to review RMP's July Update coal supply work papers
20 which were provided in mid-September and the rebuttal
21 testimony, and based on that information, I have gained
22 more comfort around those costs, though I continue to
23 disagree with the way that update was presented in the July
24 Update, as well as the lack of testimony and supporting
25 work papers supporting the changes that were made and the

1 Company's very limited responses to discovery on this
2 issue.

3 Now, in terms of the July Update, it's also
4 necessary to point out there was only a very short time to
5 review the update, and the information RMP provided in the
6 update was scant to say the least. There were significant
7 new modeling changes introduced, such as wholesale
8 revisions to the DA/RT adjustment, which were supported
9 with one or two vague sentences of testimony.

10 Also complicating the update was the fact that
11 RMP did not use its initial filing as the starting point
12 for documenting the changes that it was proposing. Rather,
13 it used a completely different Aurora model run as its
14 starting point and then worked backwards to document the
15 impact of some but not all of the changes that were made.
16 This led to an excessive \$164.2 million system balancing
17 adjustment, which was an unexplained and undocumented
18 increase to NPC relative to the initial filing.

19 In order to avoid unnecessary complication, WIEC
20 recommends that the Commission should consider requiring
21 RMP in future cases to present an update of its NPC
22 forecast with sufficient supporting testimony for each
23 material change with RMP's direct testimony NPC forecast as
24 a starting point and with the Aurora model version and any
25 other modeling changes not native to Aurora clearly

1 detailed in supporting testimony. This will help all
2 parties and the Commission better understand the inputs to
3 and the modeling assumptions around RMP's NPC.

4 Now turning to the matters in dispute. There are
5 four NPC items that are -- that remain at issue. First,
6 the Washington Climate Commitment Act, or CCA; second, the
7 day-ahead, dash, real-time or DA/RT adjustment; third,
8 market capacity limits or market caps for liquid markets;
9 and finally, third-party or non-native reserves.

10 Q. Let's take each of these in pieces. If you could
11 please explain to the Commission the adjustment that you're
12 proposing relative to the Washington CCA and the impacts
13 that that adjustment has on net power costs.

14 A. Certainly. The CCA is a Washington state policy
15 that, among other things, establishes a Cap and Invest
16 Program for greenhouse gas emissions. The policy went into
17 effect on January 1, 2023. In this case RMP has requested
18 including the costs of Washington state's greenhouse gas
19 policy in Wyoming customer rates. The impact of this
20 treatment is significant, representing an approximate \$63.4
21 million total-Company cost or \$9.1 million on a
22 Wyoming-allocated basis.

23 In my forecast, I have removed these costs.
24 There are several reasons why it is not reasonable to
25 include costs of Washington state's greenhouse gas policy

1 in Wyoming customer rates. Foremost, Washington has
2 effectively exempted its own state electric consumers from
3 the application of the CCA by providing no-cost CCA
4 allowances to cover the compliance obligations of in-state
5 loads. In PacifiCorp's ongoing rate case in Washington,
6 for example, there are no CCA allowance costs nor the
7 associated impacts on dispatch included in revenue
8 requirement.

9 Exempting in-state loads while requiring Wyoming
10 customers to pick up the tab not only undermines the
11 credibility of the program, but is unfair and unreasonable
12 to Wyoming customers.

13 Importantly, the CCA is a new policy that was not
14 considered at the time the Commission approved the 2020
15 protocol, and suggestions that the Commission is bound by
16 the terms of the 2020 protocol to include the unfair and
17 unreasonable costs of Washington state's greenhouse gas
18 policy in Wyoming customer rates is not consistent with my
19 reading of that document.

20 Despite the Company's stated position on this,
21 the CCA is not a tax. It's a policy. And the longstanding
22 principle of cost allocation in a multistate process is
23 that states are responsible for the policy costs that they
24 impose on the system.

25 Finally, as of Friday of last week, the Oregon

1 Commission agreed with this and disallowed recovery of
2 Washington's CCA costs in Oregon customer rates.

3 Q. On that point, Mr. Mullins, can I please ask you
4 to take a look at what's been marked for identification as
5 WIEC Exhibit Number 241.

6 A. Okay.

7 Q. And do you recognize this as the Oregon decision
8 that you just mentioned in your summary a moment ago?

9 A. I do.

10 MR. NELSON: Mr. Williams, I'd move for the
11 admission of Exhibit Number 241.

12 MR. WILLIAMS: Mr. Lowney, does the Company
13 object?

14 MR. LONEY: No objection.

15 MR. WILLIAMS: Miss Monahan.

16 MS. MONAHAN: No objection.

17 MR. WILLIAMS: Miss Hamilton.

18 MS. HAMILTON: No objection.

19 MR. WILLIAMS: It's received into the
20 record.

21 (WIEC Exhibit No. 241
22 Received into evidence.)

23 MR. NELSON: Thank you.

24 MR. KUMAR: I would just like to clarify
25 this is the redacted version of the order, correct, the

1 public version?

2 MR. NELSON: So I believe the answer to
3 that is yes, but can I confirm with Mr. Mullins.
4 Mr. Mullins, is it your understanding this is -- yes, I'm
5 sitting here staring at this. Yes, this is the redacted
6 version of the order. It's like I'm pretty sure. Yes,
7 sir.

8 MR. WILLIAMS: Thank you. Please proceed.

9 MR. NELSON: Which I think is good because
10 I don't think I have the nonredacted version. At least I
11 hope I don't.

12 Q. (BY MR. NELSON) Okay. Mr. Mullins, can you
13 please address now the second of the open NPC issues that
14 you mentioned earlier, and that is the adjustments or the
15 changes to the adjustment that you recommend to the day-
16 ahead/real-time issue.

17 A. Certainly. The issues surrounding the DA/RT
18 adjustment are probably the most complicated of this case,
19 although most of that complication is being driven by the
20 fact that RMP made wholesale changes to the
21 Commission-approved DA/RT adjustment method in its July
22 Update, which increased NPC by \$65.8 million on a total-
23 Company basis.

24 Making things even more complicated is the fact
25 that there was no explanation for the change, which RMP

1 said was a mere correction. RMP did not exchange its
2 justification for making this change until its rebuttal
3 testimony.

4 The DA/RT adjustment itself recognizes that RMP
5 intends to purchase more in high-priced hours and
6 correspondingly sell more in low-priced hours. Monthly
7 market prices, however, are calculated as an arithmetic
8 average over all hours in a month. Accordingly, for any
9 given market, the weighted average cost of purchases for
10 RMP is generally going to be higher than the average
11 monthly market price. Similarly, the cost of sales is
12 going to be lower than the average. These differences
13 multiplied by the volume of purchases and sales is the
14 DA/RT adjustment.

15 In the four years ending in 2022, this difference
16 resulted in an average of \$61.5 million in costs relative
17 to average monthly market prices.

18 Now, in a properly configured model, there is no
19 need for a DA/RT adjustment. Based on the hourly load and
20 hourly price inputs into the model, it will automatically
21 purchase more in high-priced hours and sell more in low-
22 priced hours resulting in a model DA/RT adjustment that is
23 consistent with the historical pattern.

24 That is the reason why we have these hourly
25 models to begin with. In the GRID model, however, the

1 opposite was occurring. There were more sales in high-
2 priced hours and more purchases in low-priced hours
3 resulting in a DA/RT -- a modeled DA/RT adjustment that was
4 negative.

5 By RMP's account, this was due to the fact that
6 the GRID model was overoptimized. In the 2015 GRC, RMP
7 developed a modeling method to address this issue. It
8 involved two steps: First, there was an adjustment to
9 market prices for sales and purchases made inside the
10 model.

11 Second, because this modeling approach still
12 produced different results than the historical impacts,
13 there was a second spreadsheet adjustment made outside of
14 the model that tied the modeled impacts back to the
15 historical average results.

16 I call this first step the price adjustment and
17 the second step the historical adjustment, although the
18 second step is sometimes referred to as the volume
19 component by the Company.

20 In its July Update, however, RMP changed this.
21 It introduced a newly coined term, "artificial arbitrage
22 revenues." The DA/RT adjustment, however, has never had
23 anything to do with arbitrage revenues. What actually
24 happened was that the first step, the price adjustment in
25 Aurora, was producing a model DA/RT adjustment of

1 approximately \$128.1 million. Subsequently, the historical
2 adjustment or volume component was reducing that impact by
3 \$66.6 million down to the historical average of \$61.5
4 million. From this we can see that, unlike the GRID model,
5 the price adjustment in Aurora was dramatically overstating
6 the DA/RT impacts relative to the historical average.

7 RMP apparently did not like this result, in its
8 rebuttal came up with a new theory that instead of being an
9 adjustment that ties the model DA/RT price adjustment back
10 to the historical average, the 66 point million dollar
11 (sic) historical adjustment was now arbitrage revenues,
12 which witness Mitchell points out that RMP has only
13 recognized approximately \$800,000 of arbitrage revenues
14 historically.

15 By conflating these two completely different
16 concepts, witness Mitchell attempts to justify essentially
17 eliminating the historical adjustment step reducing the
18 impact of that step from a \$66 million benefit down to less
19 than \$1 million.

20 This unsupported DA/RT method change should be
21 rejected. Apart from the procedural issues of introducing
22 this change in the update and explaining it in rebuttal,
23 the introduction of arbitrage revenues into the DA/RT
24 modeling method does not obviate the need for an adjustment
25 which reduces the model to DA/RT impacts back to the

1 historical average.

2 Those are separate and distinct adjustments. In
3 fact, considering arbitrage revenues would reduce the
4 impact of the DA/RT adjustment even further. Eliminating
5 this method change results in a \$61.9 million total-Company
6 or \$8.9 million Wyoming-allocated reduction in my forecast.

7 Now turning to the second part of my
8 recommendation on the DA/RT adjustment. Because the price
9 adjustment in Aurora was producing modeled impacts that are
10 so much greater than the historical average, it was
11 apparent that Aurora is not overoptimizing transactions in
12 the same way as the GRID model was.

13 When I removed the price adjustment completely
14 from the July Update, it resulted in a modeled price
15 adjustment of \$32.2 million. While these impacts are still
16 less than the historical average DA/RT impacts, they
17 produce a result that is closer to the historical results
18 than the use of the price adjustment in Aurora. Getting
19 these values is close because, in addition to the effects
20 on purchases and sales, the price adjustment also has
21 ancillary impacts on system dispatch that are not captured
22 in the DA/RT adjustment.

23 With the transition to Aurora, my recommendation,
24 therefore, is to remove the modeled price adjustment but
25 continue to make an adjustment outside of model to tie the

1 historical -- to tie to the historical DA/RT impacts
2 consistent with the Commission-approved method. This
3 change resulted in a further \$12.3 million total-Company or
4 \$1.8 million Wyoming-allocated reduction in my forecast.

5 Q. Mr. Mullins, turning to the next issue that
6 remains in dispute, can you please talk about the
7 adjustment to the market caps that you continue to
8 recommend going forward.

9 A. Certainly. Market caps are an issue that have
10 been around for a long time and subject to a great deal of
11 controversy and Commission scrutiny. Market caps are
12 limits on the amount of sales that can be made at any
13 particular market hub in the model.

14 Importantly, in the absence of market caps, the
15 ability for Aurora to model sales transactions is not
16 unlimited. This is a common misconception. Absent market
17 caps, the ability for Aurora to model transactions is
18 limited by transmission capability to the individual market
19 hubs, which represent the real-world constraint that RMP
20 faces for transacting at these locations.

21 Market caps, on the other hand, place a further
22 restriction on the ability of the model to make sales
23 transactions justified largely based on market liquidity
24 concerns.

25 In my testimony, I have recommended adhering to

1 the Commission's currently approved method for market caps,
2 which applies to illiquid markets but not to liquid
3 markets. Liquid hubs such as Mid-Columbia and Palo Verde
4 have not had market caps applied in past proceedings.

5 Note that RMP changed this assumption in its
6 direct testimony applying market caps to all market hubs
7 and offered no explanation for the change. Contrary to
8 RMP's assertion, the major power market hubs in the West
9 continue to be liquid.

10 Accordingly, I recommend that the established
11 Commission-approved method, which excludes market caps from
12 liquid market hubs, be applied in this docket. This
13 reduces NPC by 51.4 million total-Company or 7.4 million
14 Wyoming-allocated.

15 It is also necessary to point out that in this
16 adjustment I have considered the Four Corners market to be
17 a liquid market given the trading activity in relationship
18 with the Palo Verde market.

19 Most of the impact of my adjustment is being
20 driven by the Four Corners market. Approximately \$41.2
21 million total-Company or 5.8 million Wyoming-allocated of
22 my adjustment was attributable to Four Corners, whereas
23 10.2 million total-Company or 1.6 million Wyoming-allocated
24 was attributable to Mid-Columbia and Palo Verde.

25 Q. Mr. Mullins, can you now please turn to the last

1 of the adjustments that you are recommending with regards
2 to net power costs and talk about the adjustment to the
3 third-party reserves and the impact that has on your
4 recommended net power cost.

5 A. Certainly. So turning to third-party or also
6 referred to in my testimony as non-native reserves, these
7 are reserves that RMP must hold for third parties, such as
8 wind integration for non-owned wind resources and balancing
9 services for third-party non-native loads.

10 As a general principle, Wyoming customers should
11 not have to pay any more or less in rates as a result of
12 services being provided to third-party customers.

13 As we see, however, Wyoming customers are being
14 rates -- sorry.

15 As we see, however, Wyoming customer rates are
16 being increased as a result of these services, which means
17 that we are subsidizing those third-party customers, and
18 the impacts relative to the open access transmission
19 tariff, or OATT, revenues is staggering.

20 My recommendation in this case is simple. Limit
21 the modeled cost of third-party reserves included in NPC to
22 the FERC-approved costs that RMP recovers from those
23 customers. This is not a disallowance. It is merely
24 revaluing the third-party reserves in NPC in the same way
25 that FERC values them. This adjustment has impacts on both

1 regulation reserves, which is things like wind integration
2 as well as contingency reserves, which are the reserves
3 held primarily for forced outages.

4 In discovery we asked RMP to provide the amount
5 of regulation reserves attributable to third-party
6 resources in Aurora. RMP did not provide this calculation,
7 though it did ultimately provide that information in its
8 rebuttal testimony.

9 Compared to the values RMP presented, my estimate
10 in my direct testimony produced a level of third-party
11 regulation reserves that was only about 10 megawatts
12 different than RMP's calculation.

13 Accordingly, in Exhibit 212.3, I have updated my
14 calculations using RMP's calculated third-party regulation
15 reserves.

16 I have also detailed the rate recommendation
17 separately for contingency reserve services and regulation
18 reserve services. As can be seen, using the FERC-approved
19 costs for contingency services results in a \$116.3 million
20 total-Company and \$16.7 million Wyoming-allocated reduction
21 to my NPC forecast. For regulation reserves, it results in
22 a \$47.0 million or \$6.8 million Wyoming-allocated reduction
23 to my NPC forecast.

24 Collectively, these adjustments result in a \$163
25 million total-Company reduction, and this compares to the

1 approximate \$125 million value that RMP calculated for
2 these same items in rebuttal testimony.

3 Notably, with respect to contingency reserves,
4 RMP did not identify any errors or corrections to my
5 modeling. But there is a big difference with respect to
6 how I modeled the removal of third-party contingency
7 reserves and the way that RMP did.

8 As I discussed in direct testimony, RMP uses a
9 modeling technique which includes third-party loads and
10 resources in Aurora as purchases or sales, but then applies
11 an offset through a corresponding purchase and sale.

12 When I calculated my adjustment for contingency
13 reserves, I removed the third-party loads and resources
14 completely from the model, including the offsets. RMP, on
15 the other hand, simply toggled off the reserve requirement
16 for the third-party loads and resources but left the
17 offsetting purchases and sales in the model.

18 It turns out that the difference between these
19 two approaches had a major impact on NPC. In my study,
20 toggling off the third-party contingency reserves reduces
21 NPC by only \$42.1 million, whereas eliminating the
22 third-party loads and resources altogether reduced NPC by
23 \$116.3 million. This means that the reason that the cost
24 of contingency reserves is so high is due to the fact that
25 there is a \$74.1 million modeling error associated with the

1 workaround of using offsetting purchases and sales to model
2 contingency reserves, which is unrelated to the actual
3 reserves themselves.

4 When asked about this in discovery in WIEC's set
5 25, RMP could offer no explanation for this difference.
6 Accordingly, this modeling error is all the more reason to
7 simply use the FERC-approved cost for third-party reserves
8 in NPC as I have recommended.

9 Q. Finally, Mr. Mullins, in your testimony, you
10 identify several recommendations to the Commission that
11 impact the overall revenue requirement but are not
12 specifically tied to net power costs. Can you please
13 summarize your non-net power cost recommendations at this
14 time.

15 A. Certainly. So there are three additional issues
16 that I had raised. First is state tax flow-through. And
17 RMP has accrued net operating losses in all of its state
18 taxing jurisdictions and regularly does not pay any
19 material state income taxes. This is particularly true
20 given that it files consolidated returns with Berkshire
21 Hathaway and is reimbursed for tax losses that it generates
22 for the consolidated group.

23 Considering this, I recommend transitioning to a
24 flow-through method for state taxes, which will establish
25 rates only based on taxes RMP pays.

1 This approach is consistent with the way that
2 state taxes are included in rates in many states in the
3 West, including states such as California, Idaho and
4 Montana. Additionally, making such a change also frees up
5 taxes that had been formerly overpaid, which I recommended
6 be refunded to ratepayers over a three-year period. This
7 change will not just benefit customers today, but will also
8 benefit future ratepayers through reduced state income
9 taxes included in rates.

10 Second, I also recommended that the operating
11 expenses associated with Jim Bridger Units 1 and 2 be
12 removed from revenue requirement during the approximate
13 three-month period when those plants are out of service to
14 be converted to gas-fired operations.

15 Finally, in direct testimony, I presented a
16 forecast of the production tax credit rate, or PTC rate,
17 for 2024 and recommended increasing it to 3.0 cents per
18 kilowatt-hour compared to the 2.9-cents-per-kilowatt-hour
19 rate assumed in RMP's filing.

20 Since filing my testimony, the Department of
21 Commerce Bureau of Economic Analysis has issued two updates
22 to the 2023 second-quarter gross domestic product implicit
23 price deflator calculation that I used in my forecast. In
24 the September 29th update the Department of Commerce
25 changed the baseline used to calculate this index value.

1 This change makes it less likely that the PTC rate will
2 increase to 3 cents in 2024. Accordingly, while it is
3 still possible that it will increase in 2024, I am
4 withdrawing my recommendation on the PTC rate.

5 So this concludes my summary of issues included
6 in my testimony. Once again, I do appreciate the
7 opportunity to be here today and to testify before the
8 Commission, and I look forward to questions.

9 MR. NELSON: Thank you, Mr. Mullins.

10 Mr. Williams, the witness is available for
11 cross-examination questions from the Commission staff and
12 the commissioners.

13 MR. WILLIAMS: Thank you. Let's take a
14 break, and we'll reconvene at 10:25.

15 (Hearing proceedings recessed
16 10:09 a.m. to 10:25 a.m.)

17 MR. WILLIAMS: We are back on the record.

18 Mr. Lowney, do you have questions for
19 Mr. Mullins?

20 MR. LOWNEY: I do. Thank you.

21 MR. WILLIAMS: Please proceed. I would
22 note that we will take a break from Mr. Mullins' cross at
23 eleven o'clock to see if there are public comments and then
24 resume.

25

1 CROSS-EXAMINATION

2 Q. (BY MR. LOWNEY) All right. Good morning,

3 Mr. Mullins.

4 A. Good morning.

5 Q. Let's start with your tax adjustment. If you

6 could turn to Exhibit 202, which is your testimony.

7 A. Okay.

8 Q. At page 67.

9 A. Okay.

10 Q. And if you begin on line 8, you testified that

11 "In a revenue requirement calculation, two alternative tax

12 accounting methods for state income taxes can be used: 1)

13 a normalization method, as used by RMP; or 2) a

14 flow-through method as used by many other jurisdictions in

15 that the West." Do you see that?

16 A. I do.

17 Q. And then a little further down you recommend in

18 this case that "RMP transition to a flow-through method for

19 accounting for state income taxes," correct?

20 A. Correct.

21 Q. Now, if you could please flip over to page 74 of

22 your testimony. And beginning on line 22 at the bottom of

23 that page, you again testify that "Many jurisdictions with

24 a state income tax, particularly those in the West, use a

25 flow-through method for state income taxes in revenue

1 requirement." And you continue that "Several states like
2 Idaho and California, for example, have specific policies
3 requiring the use of flow-through accounting for state
4 income taxes that date back over 50 years." Do you see
5 that?

6 A. I do.

7 Q. Okay. Let's start with the state of Idaho. If
8 you could please turn to Exhibit 74 -- or excuse me,
9 Exhibit 52, my mistake.

10 A. And I apologize. It was asking me for a
11 password.

12 Q. I cannot help you with that.

13 MR. WILLIAMS: I believe it is on the
14 screen.

15 THE WITNESS: Okay.

16 MR. WILLIAMS: Were you able to get in,
17 Mr. Mullins?

18 THE WITNESS: I was, I was. Can you please
19 repeat the exhibit number.

20 Q. (BY MR. LOWNEY) Exhibit 52, it's one of Rocky
21 Mountain Power's cross-examination exhibits. It's an order
22 from the Idaho Public Utilities Commission.

23 A. Okay.

24 Q. All right. And just for context, this is an
25 order that's dated February 28, 2011. Do you see that?

1 A. I do.

2 Q. And it was in an application of Rocky Mountain
3 Power for approval of changes to its electric service
4 schedules. Do you see that?

5 A. I do.

6 Q. Now, if you could turn please to page 62 of the
7 exhibit. And at the very bottom of that page there's a
8 heading C that says, "Tax Issues."

9 A. Okay.

10 Q. And if you continue over to the next page, page
11 63 of the exhibit, the very first sentence in the first
12 full paragraph states, "The Company also requests approval
13 to move to full normalization treatment of income taxes for
14 purposes of setting rates."

15 And the next sentence says, "Staff supports this
16 recommendation." And then it says, "We accept the
17 Company's recommendation to fully normalize the repairs
18 deduction and all other temporary book-tax differences."
19 Do you see that?

20 A. I do.

21 Q. Now, your testimony, then, that says Idaho
22 requires flow-through accounting is not correct, is it?

23 A. Well, of course, PacifiCorp has sort of different
24 treatment, but for the other electric utilities, including
25 Idaho Power and Avista, those both use the flow-through

1 method for state income taxes.

2 Q. But it's not a universally applicable policy in
3 the state, is it?

4 A. Yeah, I guess not. But it is -- they do
5 explicitly use it for Avista and Idaho Power, and that was
6 based on the policy that they set, you know, many years
7 prior, and I do realize that PacifiCorp does have a
8 different treatment there.

9 Q. All right. Well, let's look at that time frame.
10 You said "many years earlier," and I believe in your
11 testimony you said these states have had these policies
12 dating back over 50 years. If you could flip back to
13 Exhibit 202. And this time to page 76.

14 A. Okay.

15 Q. And beginning on line 3, you make reference to an
16 Idaho case in which "Avista transitioned from normalization
17 to flow-through method accounting for state income taxes"?

18 A. Yep.

19 Q. Do you see that?

20 And just looking at the date of that case, that
21 was a 2010 case; is that right?

22 A. Right.

23 Q. So clearly that policy has not gone back 50
24 years, has it?

25 A. So in this particular case, it was, I guess,

1 discovered that Avista was not using the flow-through
2 method for state taxes, and that was inconsistent with the
3 state policy and inconsistent with the way it was being
4 done for at the time all the other utilities. And so they
5 required them to make a change, and that change is actually
6 quite similar to what we're recommending in this case. It
7 involved removing the deferred portion of state income
8 taxes as well as refunding the accumulated deferred portion
9 as well.

10 Q. And if you could just flip one page earlier to
11 page 75 of your testimony. You have a Table BGM-7 that
12 includes utilities that you testify use flow-through
13 accounting for state income taxes. Do you see that?

14 A. Yep.

15 Q. And you cite again Avista and you include Oregon
16 as well as Idaho, correct?

17 A. Correct.

18 Q. Now, just to be clear, Oregon has no state policy
19 requiring flow-through. Is that true?

20 A. That is true. So Avista is the only -- it's the
21 only utility in the state of Oregon that uses a state
22 flow-through method, and the distinction for Avista is that
23 they have approved state net operating loss carryforwards,
24 and because of that, you know, they weren't paying any
25 taxes. And so it was determined that they should use a

1 flow-through method rather than the normalization method
2 because that more fairly captures the actual taxes they are
3 paying.

4 Q. And thinking about other electric utilities in
5 Oregon, isn't it true that you recommended that Portland
6 General Electric Company also transition to the
7 flow-through method?

8 A. I did.

9 Q. And in response to that, Oregon Commission staff
10 opposed your recommendation because, according to them, it
11 was unfair to customers across time. Is that true?

12 A. So the Oregon litigation staff did file
13 surrebuttal testimony in Portland General Electric's recent
14 rate case where they didn't outright reject or disagree
15 with what we had proposed. They didn't necessarily agree
16 with it either. They said that they might be open to it if
17 the amortization period was longer. And since that was
18 rebuttal testimony and the case was ultimately settled, we
19 never responded or dealt with that, that issue.

20 Q. And that settlement, just to be clear, did not
21 require Portland General Electric to transition to
22 flow-through, correct?

23 A. Right. So the settlement covered a large number
24 of issues. So with Portland General Electric, we have a
25 pretty good track record and relationship with them where

1 we very frequently settle cases. And I wasn't involved in
2 this particular settlement, but I do know there were a lot
3 of sort of give-and-take items in the settlement, and I do
4 know that my, you know, particular customers were
5 comfortable with the end result of that settlement.

6 Q. Okay. If you could turn to page 67 of Exhibit
7 202.

8 A. Okay.

9 Q. And I'm going to direct your attention to the
10 very last line, line 23.

11 A. Okay.

12 Q. Where the sentence begins, "A normalization
13 method spreads the impact of income taxes, which are
14 usually more favorable taxwise than book accounting over
15 the book life for the underlying tax item." Do you see
16 that?

17 A. I do.

18 Q. And then a little further down in that same
19 paragraph beginning on line 9, you testify that "In any
20 given year, it is typical for the normalization method to
21 result in ratepayers paying more taxes in revenue
22 requirement than the utility actually pays with the excess
23 applied as a reduction to rate base through accumulated
24 deferred income taxes, or ADIT" -- that's A-D-I-T.

25 And you continue on, "The excess taxes paid are

1 called deferred taxes and often characterized as a source
2 of zero cost financing or an interest-free loan and thus
3 justified as a reduction to rate base." Do you see that
4 testimony?

5 A. I do.

6 Q. Now, while you call it an interest-free loan, in
7 fact, customers do earn interest equal to the Company's
8 weighted average cost of capital for those deferred tax
9 balances; isn't that true?

10 A. Yeah, I think that's a fair characterization. So
11 it's -- you know, it's an interest-free loan to the
12 utility, and they include that in rate base as a reduction
13 to rate base, and ratepayers get the benefit of that. So
14 from some perspective, it's kind of like the ratepayers
15 giving PacifiCorp a loan and earning interest on that loan.
16 And I guess kind of the question is whether, you know,
17 ratepayers really should be giving loans to the utility or
18 not, you know, particularly in light of some of the unique
19 circumstances for PacifiCorp.

20 Q. Now, if you could flip forward, please, to page
21 73 of that same exhibit.

22 A. Okay.

23 Q. Beginning on line 16 you testified that, "Under a
24 normalization method of accounting, one would expect to pay
25 more taxes than the utility pays in the early years of an

1 asset's life and less taxes than the utility pays in the
2 later years of an asset's life, as deferred taxes reverse.
3 In practice, however, this reversal, and the benefit of
4 paying less taxes than the utility in revenue requirement,
5 never occurs." Do you see that?

6 A. I do.

7 Q. And in the next sentence you attribute that to
8 ongoing property additions, which means that "...any
9 reversals are continually being offset by incremental
10 deferred taxes," and so "ratepayers can have little
11 expectation of an eventual situation of paying income taxes
12 less than what the utility pays to the reversal of formerly
13 contributed deferred taxes."

14 Now, if I could refer your attention to Exhibit
15 37, please. And I'm going to direct your attention to page
16 6 of the exhibit, which is sort of hard to see
17 unfortunately, but it's easier if you track it, it's page
18 17-11 of the original document.

19 A. Okay.

20 Q. And under the heading sub (a), it says, "The
21 Attack on Normalization--The Phantom Tax Argument." Do you
22 see that?

23 A. I do.

24 Q. And the first sentence says, "In regulatory
25 proceedings, opponents of normalization often resort to the

1 'phantom tax' argument." And it continues, "The argument
2 relies on the assumption that, because a utility's business
3 would probably continue to grow, the deferred tax account
4 will also continue to grow indefinitely. The phantom tax
5 advocates contend that, as the deferred taxes grow at a
6 rapid pace, there will always be more revenues collected to
7 cover the deferred tax expense than the deferred taxes paid
8 out. They further allege that this gives rise to a
9 permanent tax savings rather than a tax deferral that would
10 eventually be paid out when temporary differences reach a
11 reversal." Do you see that?

12 A. I do.

13 Q. And you would agree that's essentially describing
14 what you just walked through in your testimony, correct?

15 A. I think generally, but, you know, I probably
16 wouldn't call it the phantom tax argument, per se. I mean,
17 it's -- you know, I don't think I would disagree with
18 anything that is said in this section. So I think it is
19 similar to long-term debt where the debt is continually
20 being refinanced at higher and higher levels, but I think
21 the point that I am making here is that really the taxes
22 that are paid are always going to be less than the total
23 tax expense because of this situation. And recognizing
24 that this is a, you know, it's a complex issue, and it's
25 hard to -- you can't -- you know, it's hard to boil it down

1 to just these, you know, simple words.

2 But at the end of the day, you know, using one
3 method or another, you know, over time it results in the
4 same amount of tax paid. It's just really a matter of
5 timing. Do we pay more today and give a loan to the
6 Company and earn interest on that or do we just pay what
7 the Company pays.

8 Q. Well, and I will agree with you this is a complex
9 issue, and I'd like to direct your attention to the next
10 page of the same exhibit. So that would be 17-12 or page 7
11 of the exhibit. And the first full paragraph states, "The
12 National Regulatory Research Institute in a study of" this
13 what you referred to as a complex issue "concluded that the
14 phantom tax argument," which is the argument I think we
15 just established you made in your testimony, is quote
16 "oversimplified to the extent it being misleading and
17 fallacious." Do you see that?

18 A. I do. And the point here is not to say -- so
19 when people talk about the phantom tax argument, they're
20 arguing that there are taxes being paid in rates that the
21 utility never pays, and that's not what I'm saying here.
22 So really it's a timing issue. So do we pay more today and
23 give a loan to the Company or do we just pay what the
24 utility pays.

25 And so I think while I talk about the growth of

1 deferred taxes and how they never revert, I'm not making
2 this argument that there are taxes being paid into rates
3 that the utility never paid. It's really just a timing
4 issue.

5 Q. Well, and let me just revert or refer you back to
6 page 74 of your testimony because what I'm hearing you say
7 today is very different than what you put in writing.

8 So on the top of page 74, on line 1, and this
9 follows on the discussion we already reviewed. It says,
10 "From this perspective, the interest-free loan provided by
11 ratepayers is never repaid. It's continually and
12 constantly refinanced with higher and higher principal
13 balances."

14 Now, setting aside the fact we already
15 established it's not, in fact, an interest-free loan, your
16 testimony says it's never repaid, which is the misleading
17 and fallacious argument that we just discussed. Now I'm
18 hearing you say something very different. So are you
19 changing your testimony today and acknowledging, in fact,
20 the phantom tax argument does not apply?

21 A. So unpacking that a bit. So there were a lot of
22 statements made in that that I don't necessarily agree
23 with. So this phantom-tax issue is -- it's the argument
24 that there are taxes paid in rates that the utility doesn't
25 pay, and I'm not saying that.

1 I'm saying -- the question is -- and I agree
2 completely that there are -- that it's like debt. That
3 these balances grow over time, but because there are new
4 capital additions, they never really reverse.

5 And so the question here and what I'm saying here
6 is, you know, we're giving this loan to the Company that's
7 never really repaid, and so does it make sense to keep --
8 for ratepayers to loan this money to the Company,
9 particularly when we're dealing with 23-plus percent rate
10 increases.

11 Q. Thank you, Mr. Mullins. Let's move on to your
12 net power cost adjustments. So maybe just to get our
13 bearings, if you could turn to page 7 of Exhibit 202. It's
14 your testimony.

15 A. Okay.

16 Q. And if we can just look at Table BGM-1.

17 A. Okay.

18 Q. This was your initial recommendation, which had a
19 total-Company net power cost of \$1.989 billion. Do you see
20 that?

21 A. I do.

22 Q. And I understand from the discussion today that
23 you've revised that recommendation, and I believe if I
24 wrote the number down correctly, it's now \$2.165 billion;
25 is that correct?

1 A. Yeah, 2.166 billion. It's possible that I
2 rounded that wrong.

3 Q. And that was found in the exhibit that was
4 admitted just before your summary that's 212.3; is that
5 correct?

6 A. Correct.

7 Q. And just to be clear, the 212.3 presents your
8 adjustments in a very similar way to this Table BGM-1, and
9 in the way that you calculated your adjustments, you
10 performed them sequentially; is that correct?

11 A. That's correct.

12 Q. And so, in other words, the valuation of the item
13 on line 6, the DA/RT July Update method in Exhibit 212.3,
14 that valuation presumes you've also previously removed the
15 Washington CCA costs, correct?

16 A. That's right. That's right. And depending on
17 how the order is performed, it might impact some of the
18 numbers.

19 Q. Okay. Now, if we could turn back to Exhibit 202
20 and page 19.

21 A. Okay.

22 Q. And the first question on line 2 of that page
23 addressing the system balancing adjustment. Do you see
24 that?

25 A. Yep.

1 Q. And on line 10, you refer to that as an
2 "unexplained adjustment." And I believe you said the same
3 thing in your summary this morning; is that correct?

4 A. Yeah.

5 Q. And on line 19 you testify, "In other words, the
6 system balancing adjustment is a plug figure that RMP added
7 into its July Update forecast to account for the fact that
8 the sum of the individual adjustments RMP documented in
9 supplemental direct testimony do not produce the same level
10 of NPC as the final July Update forecast." Do you see
11 that?

12 A. I do.

13 Q. Now, Mr. Mullins, you regularly include the same
14 types of balancing adjustments in your testimony in other
15 cases. So let's take a look at a recent example. If you
16 could turn, please, to Exhibit 27. And this is testimony
17 you provided in Portland General Electric Company's general
18 rate case, and it was filed in May of 2023. Do you see
19 that?

20 A. I do. And you did make a statement earlier that
21 I regularly include this type of adjustment. And so I
22 wouldn't agree with that necessarily, but there are cases
23 when I use a balancing adjustment in presenting, you know,
24 power cost impacts and revenue requirement.

25 Q. Okay. Well, that's fair. But you agree you do

1 it somewhat regularly?

2 A. Not necessarily. So, I mean, there's two
3 different ways that you can present an impact study in a
4 rate case. So at least two different ways. So one way is
5 you calculate your adjustments sequentially one after
6 another, and each adjustment afterwards includes the impact
7 of the adjustment prior. The second way -- and so we would
8 call that first way a step change study.

9 The second way is where you start with the
10 original numbers or the original study, and you make
11 individual changes to that study, and you calculate the
12 impact of each of those changes. And in the end, you
13 combine them all together, and you calculate the total.
14 And because there are -- there will be offsetting
15 relationships between the different adjustments, you
16 include a balancing adjustment to account for the noise.

17 And so I think the issue here is it's not
18 necessarily that they've done it this way, that RMP has
19 included a balancing adjustment. It's just the, one, the
20 magnitude of it. So \$164.2 million is quite a bit of noise
21 in the model.

22 And then secondly, as I discussed in my summary,
23 they really started from the end result and worked
24 backwards. They didn't start from the initial filing and
25 work forwards. And so because of that, it was virtually

1 impossible to see what was driving that \$164.2 million.

2 So while it is true that I have -- I do commonly
3 use that approach in power cost, not always, I think
4 there's some major distinction with what I'm saying in this
5 testimony between and what, you know, the types of
6 adjustments that I've done in the past.

7 Q. And just to be clear, in your answer just a
8 moment ago, you said the balancing adjustment is the result
9 of "noise in the model." And, in fact, it's the result of
10 the fact that, when you do sequential studies like you have
11 done, your own testimony in this PGE case says the impacts
12 are skewed by the order in which the adjustments were
13 calculated, correct?

14 A. So in each one of these studies and each case,
15 you have to exercise judgment about how you present these
16 impacts. So different types of adjustments might impact
17 things differently, and so you may want to present it in a
18 different way.

19 And in this case, there were actually some very
20 specific reasons with these adjustments for why I presented
21 it this way. And so it turns out in this study there were
22 two specific adjustments that, if you did them together,
23 they resulted in a much larger impact. And so if I were to
24 perform this sequentially, which I had -- usually do for
25 PGE, I'll do a sequential study, but if I had done that, it

1 would have overstated the impact of those individual
2 adjustments. And so I didn't want to present those
3 adjustments as being larger than the impacts that I thought
4 they were. And so that's why I would have -- that's why I
5 did that in this case.

6 But there are other cases, specifically with PGE,
7 where I've just done sequential studies. So it really
8 depends on the case and the type of adjustments that you're
9 performing.

10 But at the end of the day, and I think it may be
11 redacted in this, you know, if you're seeing a very large
12 system balancing adjustment, it means that you're not
13 accurately depicting the adjustments up above. And so you
14 need to go back and figure out what's causing that
15 adjustment and explain it.

16 And so that's the -- I think concern that we had
17 with the update filing is, you know, there's nothing wrong
18 with the system balancing adjustment. It's just that there
19 was no explanation of what was driving it. And trying to
20 work backwards to try to figure that out was virtually
21 impossible.

22 Q. Now, let's move on to your adjustment for what
23 you call non-native reserves. Now, as a general matter,
24 your adjustment addresses the provision of contingency and
25 regulation reserves that are provided to third-party load

1 and generation that's located within the Company's
2 balancing authority area; is that correct?

3 A. Correct.

4 Q. And you agree that the Company is required to
5 provide those reserves pursuant to its open access
6 transmission tariff, or OATT?

7 A. Yes.

8 Q. Okay. If you could turn to page 61 of Exhibit
9 202. That's your testimony. And at the very top, line 6,
10 you testify that "For contingency reserves, a utility is
11 required pursuant to NERC standards to have generation
12 capacity available to respond within ten minutes in a
13 contingency event such as a forced outage. Thus, rather
14 than selling a full output of a resource into the market, a
15 resource that's holding reserves must be dispatched down to
16 be capable of responding to such events resulting in an
17 opportunity cost to the utility." Do you see that?

18 A. I do. And I guess to clarify, it wouldn't just
19 be selling the full output of the resource into the market.
20 It could also be being used to serve customer loads.

21 Q. And just to be clear, in actual operations, you
22 agree that the Company must hold required reserves in order
23 to comply with its NERC standards, correct?

24 A. I do.

25 Q. So in actual operations, there is no opportunity

1 to sell the full output of a resource into the market or to
2 serve customers with that resource if it's holding
3 reserves?

4 A. I think that maybe the logic there is circular.
5 So here I'm saying if it's not holding reserves, you know,
6 if it didn't have to hold those reserves, it would be able
7 to -- the power costs wouldn't be so high due to its
8 ability to use that resource to serve loads or to sell into
9 the market.

10 Q. And I guess what I think we agreed on is that the
11 Company's required to hold those reserves, correct?

12 A. Yes.

13 Q. And if they are holding reserves, those resources
14 cannot be used to serve customers or sell into the market,
15 correct?

16 A. I guess that's right.

17 Q. Now, on that same page 61, if you could go down
18 to line 19, and you say there, "Since the reserve capacity
19 cannot be used to serve native retail customers or sold
20 into the market for the benefit of native retail customers,
21 regulating reserves held for non-native customers result in
22 a material cost to RMP." Do you see that?

23 A. I do.

24 Q. Now, in order to quantify the impact of that cost
25 that you describe, and I think you said this in your

1 summary, you removed the reserves from the net power cost
2 model, correct?

3 A. Right. So my recommendation is to use the
4 FERC-approved rates.

5 Q. Mr. Mullins, I'm just trying to ask you how you
6 modeled it.

7 A. Right.

8 Q. We'll get to the FERC issue in a moment, but can
9 you just verify for me that the way that you modeled this
10 cost that you describe on line 21 is by removing the
11 reserve requirements from the model?

12 A. Right. So the way that I modeled it was I
13 modeled the FERC required reserve requirements in the model
14 using the FERC-approved rates, and I removed the
15 corresponding reserves that were included in the dispatch
16 in the model from the model.

17 Q. So, in effect, what you did was you allowed the
18 resources that the model was holding in reserve to instead
19 be dispatched into the market or used to serve retail
20 customers, correct?

21 A. So I -- right. So I guess it's the same
22 statement as before. So I included the FERC-approved costs
23 as the cost, and then I took out the modeled cost because
24 the models cost was several multiples higher than the
25 FERC-approved cost. So we're not saying that those should

1 be removed entirely. We're just saying to limit them to
2 the FERC-approved cost.

3 Q. Well, and just to be clear, then, what we've
4 established is that, in actual operations, the Company
5 cannot use those resources to sell into the market or to
6 serve load. But your modeling does use those resources to
7 sell into the market or to serve load, correct.

8 A. So my modeling, as I said, it adds in the
9 FERC-approved cost and removes those reserves from the
10 model. And by doing that, it's including those costs, but
11 then the model is dispatching around the reserves. So I
12 wouldn't necessarily characterize it the way that the
13 question was asked.

14 Q. Well, just to be clear, when you say "dispatching
15 around the reserves," what you mean is resources that, in
16 the real world, would be holding reserves are, in your
17 modeling, being dispatched so they can sell energy into the
18 market.

19 A. Right. So the dispatch is complicated. It
20 involves, you know, when you -- and the cost of reserves is
21 equally complicated, but when a resource is holding
22 reserves, it's not able to serve load, and it's not able to
23 sell into the market. So that certainly would be a
24 component of it. However, as a replacement for those
25 costs, we added back in the FERC costs. And so it's not as

1 if there are -- there are no costs of reserves in the model
2 or in my recommendation. It's just that they're limited to
3 that FERC number.

4 Q. Let's talk about that. So in WIEC 212.3, which
5 is your updated net power cost recommendation, you updated
6 your adjustment such that it's \$163 million total-Company
7 or roughly \$24 million Wyoming-allocated adjustment. Does
8 that sound about right?

9 A. Yep.

10 Q. And, again, this was done sequentially, so the
11 order of the adjustment in all of your adjustments matters,
12 correct?

13 A. Correct.

14 Q. So we don't know the true impact of just this
15 adjustment on its own, right?

16 A. Yeah, I do know that. I mean, it, of course,
17 depends on, you know, a lot of things.

18 Q. And what are you looking at? Is this in the
19 record?

20 A. These are just my notes, so if you're --

21 MR. WILLIAMS: Mr. Lowney, I apologize for
22 interrupting, but it is eleven o'clock. If we could take a
23 pause.

24 MR. LONEY: Yes.

25 MR. WILLIAMS: At this point I do believe

1 we have one public commenter at least on Zoom. So let me
2 at least ask in the room, is there anyone here who would
3 like to make a public comment at this time?

4 Let the record show no response.

5 Mr. Phetteplace, I believe Mr. Deny felled der is
6 online.

7 MR. PHETTEPLACE: Correct. I just now sent
8 him the request to unmute.

9 MR. DEGENFELDER: Good morning. Am I on
10 the line?

11 MR. WILLIAMS: You are, sir. Would you
12 please, sir, state and spell your name for the record.

13 MR. DEGENFELDER: Yes, for the record, my
14 name is Steve Degenfelder. That's D-e-g-e-n-f, as in
15 Frank, e-l-d-e-r.

16 MR. WILLIAMS: And sir, you are a customer
17 of Rocky Mountain Power?

18 MR. DEGENFELDER: Yes, I work for a company
19 that is a customer of Rocky Mountain Power.

20 MR. WILLIAMS: Please proceed with your
21 statement.

22 MR. DEGENFELDER: Thank you. Good morning,
23 Chairman Throne, Deputy Chairman Petrie and Commissioner
24 Robinson. Thank you for the opportunity to make public
25 comment on this very important issue. My name is Steve

1 Degenfelder. I work for Kirkwood Oil & Gas, LLC. It's a
2 private family-owned company in business since the 1960s.
3 Besides developing new exploratory prospects in the state,
4 the Company's operating affiliate also operates about 300
5 oil and gas wells in Wyoming and has a monthly electric
6 bill of \$315,000.

7 While most of the discussion about this case is
8 centered around what it will mean to residential rates, I
9 am here to ask you to pay careful attention to what the
10 rate increase will do to small and midsize industrial
11 ratepayers like Kirkwood.

12 The largest oil and gas producers are represented
13 by the Wyoming Industrial Energy Consumers, and we
14 certainly appreciate and support their work as intervenors
15 in this case. However, there are hundreds of smaller oil
16 and gas producers in Wyoming just like Kirkwood. The
17 average production of our wells is less than 5 barrels per
18 day per well. That doesn't sound like very much, but in
19 2022, the Company paid over \$7 million in royalties,
20 severance taxes and ad valorem taxes to the state and
21 various counties in Wyoming.

22 While we do not have the scale of larger
23 operators, make no mistake that, just like them, power
24 costs make up a very significant portion of our cost of
25 doing business. In fact, I'd wager that, as a percentage

1 of our operating margin, power costs are more significant
2 for us small operators.

3 A 30 percent increase will inevitably put
4 pressure on our end-of-life wells and could very well make
5 them uneconomic requiring them to be plugged and abandoned.

6 Let me be clear, when those wells are plugged and
7 abandoned, the associated royalties, severance taxes and ad
8 valorem taxes I previously stated that would be paid will
9 also go away.

10 This increase for Kirkwood is material and means
11 we are going to have to make tough decisions about future
12 investment in oil and gas projects. Oil and gas is a
13 primary economic driver in Wyoming, and small operators
14 like us are a big portion of that economy. If we are
15 forced to manage a 30 percent increase in power costs, the
16 consequences will go well beyond just our business.

17 The proposed increase by Rocky Mountain Power
18 appears to be related to increased fuel costs and demand-
19 related third-party power purchases. Everyone is aware of
20 inflation and natural gas price spikes we saw at the end of
21 2022 and the beginning of 2023. Rocky Mountain Power is
22 currently recovering the increased fuel costs through their
23 7 percent cost recovery that came into effect in July 2023.
24 Natural gas prices have dropped in the latter part of 2023,
25 and the differential prices seen for gas going west has

1 gone down.

2 The law requires rates to be just and reasonable.

3 A 30 percent rate increase on Kirkwood is not just or
4 reasonable.

5 For the reasons stated above, I respectfully
6 request that the Commission approve a lower rate of
7 increase more in line with the national inflation rates of
8 8.8 percent in 2022 and 6.6 percent in 2023.

9 Thank you for the opportunity to address and make
10 comments to the Public Service Commission on Rocky Mountain
11 Power's proposed rate increase and its actions on Kirkwood
12 Oil & Gas. Thank you.

13 MR. WILLIAMS: Thank you, sir.

14 Are there any other individuals on the Zoom Link
15 who would like to offer public comment?

16 MR. PHETTEPLACE: No raised hands.

17 MR. WILLIAMS: Thank you.

18 DEPUTY CHAIRMAN PETRIE: Mr. Williams.

19 MR. WILLIAMS: Yes.

20 DEPUTY CHAIRMAN PETRIE: I'd like, if you
21 might, to ask Mr. Degenfelder the source of the inflation
22 numbers that he just cited.

23 MR. WILLIAMS: Certainly. Mr. Degenfelder,
24 are you there?

25 MR. DEGENFELDER: Yes, I'm here.

1 MR. WILLIAMS: Did you hear the Deputy
2 Chairman's question, sir?

3 MR. DEGENFELDER: Yes, that figure was
4 given to me by one of our petroleum engineers. I can chase
5 down the exact source of where he got that figure.

6 MR. WILLIAMS: Are there other questions
7 from the bench for Mr. Degenfelder?

8 CHAIRMAN THRONE: Could we ask if all of
9 his wells are in Rocky Mountain territory?

10 MR. WILLIAMS: Did you hear,
11 Mr. Degenfelder? Are all of your wells in Rocky Mountain
12 territory?

13 MR. DEGENFELDER: Madam Chairman, no. Some
14 of ours are through the local REAs, but we fully expect
15 with these cost increases that we'll see those with the
16 local REAs as it's worked its way through.

17 CHAIRMAN THRONE: Thank you.

18 MR. DEGENFELDER: But not all the wells are
19 under Rocky Mountain Power.

20 MR. WILLIAMS: Any other questions?

21 Thank you, Mr. Degenfelder.

22 MR. DEGENFELDER: Thank you.

23 MR. WILLIAMS: Mr. Phetteplace, has anyone
24 else raised a hand at this point?

25 MR. PHETTEPLACE: No raised hands, sir.

1 MR. WILLIAMS: Thank you.

2 Mr. Lowney, please proceed.

3 CROSS-EXAMINATION RESUMED

4 Q. (BY MR. LOWNEY) Okay. Well, Mr. Mullins, let's
5 use the \$163 million figure you include in the record as
6 the valuation for your adjustment. And you agree that the
7 Company recovers roughly \$12 million total-Company for the
8 provision of reserves under its OATT rates; is that
9 correct? I can direct your attention to page 63 of your
10 testimony where you have that quantification.

11 A. Yeah, that is correct. And yeah, \$12.2 million,
12 and in performing our adjustments, we removed the reserves
13 that were modeled in Aurora, and we added back that cost,
14 those revenues as the cost of reserves. So we're tying
15 back to the FERC-approved rate.

16 Q. Well, that's what I'd like to talk about. So
17 just to get our math right, and again, I'm rounding, but
18 the difference between the \$163 million calculation you
19 make and the \$12 million OATT rates is about \$151 million
20 rounded, correct?

21 A. No. Because the 166 is net of the \$12.2 million.
22 So my study -- so if you were to not include the \$12.2
23 million, it would be about 175 million. So the model
24 impacts are higher than the 166.3.

25 Q. So the gap, then, is \$163 million.

1 A. Right. Exactly, between the forecast costs,
2 which were about 175, and the additional cost to cover the
3 revenues, which were added into the forecast.

4 Q. Okay. Now, if we could turn to page 65.

5 A. Okay.

6 Q. On line 8 of your testimony, you testify that
7 "...the costs of serving non-native loads and resources
8 should be paid for by those loads and resources," correct?

9 A. Sorry, what was the line?

10 Q. Line 8. "...the costs of serving non-native
11 loads and resources should be paid for by those loads and
12 resources." Do you see that?

13 A. Right, as a general principle.

14 Q. And a little further down on line 13 you refer to
15 these as "revenue shortfalls." Do you see that? And that
16 was also the word you used in the table we were looking at
17 on page 63 of your testimony, Table BGM-3 referred to as a
18 revenue shortfall. Do you see that?

19 A. Right. So the revenues from the OATT rate do not
20 cover the cost of serving those customers as measured by
21 Aurora. So the cost is about \$175 million versus the \$12.2
22 million. And so the revenue shortfall I'm referring to
23 there is the difference between those two values.

24 Q. And on line 14 of that same page 65, and I'll
25 paraphrase here, but you basically say, if the OATT rates

1 are inadequate to recover that revenue shortfall, the
2 Company should go to FERC and fix its rates. Is that a
3 fair summary of that testimony?

4 A. I might not say "fix its rates." I think this
5 speaks for itself.

6 Q. Okay. Well, just to be clear, then, implicit in
7 your adjustment is a request that this Commission determine
8 that the FERC rates are unreasonable and don't reflect the
9 true cost of providing reserves; isn't that right?

10 A. No, I think exactly the opposite. So I'm
11 actually using the FERC cost as the cost of reserves.

12 Q. But I think you just said in your testimony, "If
13 the FERC-approved rates are inadequate to recover the costs
14 of serving non-native customers, it would be appropriate
15 for RMP to seek to recover those funds through its FERC
16 rates."

17 A. Yeah. I --

18 Q. Doesn't that mean the FERC rates are insufficient
19 to recover the costs as you've calculated them?

20 A. I think that would be a determination for RMP to
21 make. I think, as we look at this case, however, the costs
22 that are being proposed in net power costs are an order of
23 magnitude higher than the costs that FERC calculates. And
24 so, you know, to the extent there's -- you know, those FERC
25 rates are -- if PacifiCorp finds them to be inadequate,

1 then I think that's something they would need to address.

2 Q. Well, just to be clear, Mr. Mullins, you found
3 those FERC rates to be inadequate because your testimony is
4 that there is a \$163 million difference between how you
5 calculate the cost of reserves by removing them from the
6 model and the way FERC calculates the cost of reserves
7 under its OATT rates, correct?

8 A. I wouldn't say it that way. I mean, I think the
9 Aurora model, the way that PacifiCorp has configured it, is
10 including much more costs than the FERC rates. And so, you
11 know, I'm not making any judgment on how those FERC rates
12 are calculated, but rather, saying that, you know, the
13 costs included in rates are limited to what's recovered and
14 the costs that FERC determines.

15 Q. And so essentially, then, what you're saying is
16 that the Commission should set retail rates as if the
17 Company were receiving significantly more revenue for the
18 provision of reserves than it is currently authorized by
19 FERC, correct?

20 A. Yeah, I probably wouldn't say that again. I
21 think my recommendation speaks for itself. My
22 recommendation is to include only the FERC-approved costs
23 and nothing more. The way that the model is configured it
24 has -- you know, there's much higher costs being included
25 in NPC, and I don't think that Wyoming customers should be

1 required to subsidize non-owned third-party, you know, wind
2 and loads.

3 Q. And so, again, that subsidy can only happen,
4 though, if there's a finding that the FERC rates are
5 insufficient to cover the cost of reserves as you've
6 calculated them?

7 A. I mean, I think it would be an insufficiency
8 maybe in the modeled costs. I mean, we're seeing in the
9 model there's quite a bit higher costs. So I think if
10 PacifiCorp thinks that that cost is there, then I think
11 it's between them and the FERC to try to recover those
12 costs. But I don't think that Wyoming customers should be
13 kind of in the cross-hairs of that particularly when we're
14 dealing with such a large rate increase.

15 Q. Now, Mr. Mullins, are you familiar with WIEC
16 witness Mr. Higgins and particularly his testimony relating
17 to energy cost adjustment mechanism or ECAM?

18 A. You know, I didn't review that in detail, and I'm
19 not the witness for that.

20 Q. Well, let me just ask you, would you agree that
21 one of the purposes of the ECAM is to set an accurate net
22 power cost forecast?

23 A. I don't think -- I don't know that's the purpose
24 of the ECAM itself. I mean, I think I would probably defer
25 to Mr. Higgins on what the purpose of the ECAM is. I

1 certainly think that that's an important consideration, but
2 I wouldn't say that's an ECAM purpose necessarily.

3 Q. But you would agree, I guess, generally the net
4 power cost forecast should be set as accurately as
5 possible, and to be an accurate forecast, it should reflect
6 actual operations, correct?

7 A. So the forecast should be accurate and from a
8 normalized basis. So, you know, when you set the net power
9 cost level, I think we recognize that there may be some
10 years when it's higher, some years when it's lower, and so
11 really the idea is to strike that balance.

12 And I'm sorry, I forgot the second part of your
13 question.

14 Q. Well, would you agree that an accurate forecast
15 should track actual operations? In other words -- let me
16 restate that. It's a poorly way to say it.

17 In order to produce an accurate forecast, that
18 forecast should reflect actual operations. Wouldn't you
19 agree?

20 A. I think at the end of the day we're mostly
21 concerned about the costs and the prudently incurred costs.
22 And so to the extent that coal plants dispatch more or less
23 or there's more sales than purchases, if we can get the
24 cost values right, I think that's a higher consideration
25 than going into the model and seeing whether individual

1 plants perfectly operated in the future the way that we
2 thought that they would have.

3 Q. Well, I guess what I'm asking you is do you think
4 that the forecast should reflect actual operations in the
5 general assumptions that are used to either craft an input
6 or to design and operate the model?

7 A. So as a general principle, we do design the
8 forecast around the actual capabilities and -- or actual
9 expectations of how those plants will dispatch and things,
10 but at the end of the day, it's really the costs and the
11 baseline that matters.

12 Q. Now, I'm going to ask you another question about
13 the ECAM, and I understand if you can't answer it. But
14 would you agree that Mr. Higgins testifies that one of the
15 purposes of the ECAM is also to create an incentive for the
16 Company to control its costs in actual operations?

17 A. I think I would defer to Mr. Higgins on that.

18 Q. Now, setting aside that deferral, would you agree
19 that in order for the Company to realize the net power cost
20 savings included in your adjustment, the Company would have
21 to stop holding reserves that are required in order to
22 ensure a reliable system?

23 A. I'm sorry, could you repeat that.

24 Q. In order to realize the cost savings that your
25 adjustment assumes, the Company will be incented to stop

1 holding reserves that it is required to hold in order for
2 the system to remain reliable.

3 A. Okay. So a couple of things. So, first, it's
4 not really cost savings. So we're -- as I mentioned, we're
5 just limiting the costs included to what the FERC rate is.
6 And we're not necessarily saying that they're not going to
7 hold those reserves, but just that the costs included
8 should be limited to what, you know, what FERC approves.

9 And as far as, you know, dealing with that in the
10 ECAM and actual operations, it's something I have thought
11 about some, but I think those would be details that we
12 would need to work through going forward.

13 Q. Well, and just to be clear, though, the way you
14 calculated your cost savings, the reduction to net power
15 cost was by removing the reserves from the forecast,
16 letting those resources being sold into the market or used
17 to serve customers, correct?

18 A. I think this will go back to kind of the sort of
19 repeating response that we initially took those reserves
20 out, but then we added back the FERC-approved costs for
21 those reserves into the model. So it's not as if there are
22 no reserves in the model.

23 Q. Well, just to be clear, you've added back the
24 costs, but the model is dispatching resources that in
25 actual operations cannot be dispatched, and that's how

1 you're achieving the savings that you include your
2 adjustment; isn't that right?

3 A. Not necessarily. So by adding in the costs,
4 there are -- implied in that there are the system costs of
5 those reserves. So while that's not in the Aurora model,
6 per se, it is implied in the costs that are being added
7 back in.

8 Q. So the model is holding reserves back? In other
9 words, it is not freeing up resources?

10 A. So, as I mentioned, so that would be implied in
11 the costs that are added back in. But when you remove
12 those reserves from the Aurora model, it does re-dispatch
13 around those and either use them to serve loads or to
14 reduce purchases is another area where it impacts it or to
15 make sales, but then we add back in the FERC-approved
16 costs. And so that correspondingly eliminates those -- the
17 ability to make sales and purchases on that amount.

18 Q. Okay. Mr. Mullins, let's move on. In your
19 summary, you made reference to a recent -- well, recent,
20 last Friday order issued by the Public Utility Commission
21 of Oregon in the Company's 2024 transition adjust mechanism
22 or TAM proceeding. Do you recall that?

23 A. I do.

24 Q. Now, you were a witness in that case; isn't that
25 right?

1 A. I was.

2 Q. And Exhibits 21 and 22 in this case is your
3 testimony from that case; is that correct? Have you looked
4 at those exhibits? It's filed on behalf of the Alliance of
5 Western Energy Consumers. And maybe we'll turn to Exhibit
6 21 first just to get our bearings. This was your open
7 testimony that was filed on June 23rd of 2023. Do you see
8 that?

9 A. Okay.

10 Q. And then Exhibit 22 is your rebuttal testimony
11 which was filed on August 16th. Do you see that?

12 A. I do.

13 Q. And just for context, your testimony in this case
14 was filed on August 14th. So two days before this Oregon
15 testimony was filed; is that correct?

16 A. That is correct.

17 Q. Okay. If you could turn to page 4 of Exhibit 22.

18 A. Okay.

19 Q. And that table, which is Table 1, is your
20 recommendation in the TAM for the net power cost
21 adjustments, correct?

22 A. Correct.

23 Q. And if we just compare that to the same table on
24 page 7 of your testimony in this case.

25 A. Okay.

1 Q. My apologies if we have to flip back and forth.
2 I'd just like to identify the similarities between those
3 two tables. Are you at -- do you have in front of you -- I
4 apologize we're going to have to flip back and forth a
5 little bit between Table BGM-1 on page 7 of your testimony
6 in this case and Table 1 on page 4 of Exhibit 22.

7 A. All right. Okay.

8 Q. And just looking at those two tables, they're
9 fairly similar, correct?

10 A. Yep.

11 Q. In fact, even in your Oregon testimony, you refer
12 to the RMP July Update; isn't that right?

13 A. In that the -- sorry, which exhibit? The 202?

14 Q. Exhibit 22. This is your Oregon testimony, but
15 you make reference to RMP on line 1 of Table 1.

16 A. Right, yeah. So that was a typo in that case.

17 Q. And just to be clear, if we flip back to your
18 Wyoming testimony in this case, Table BGM-1 has total-
19 Company net power cost forecast of \$1.989 million, which
20 has subsequently been increased in WIEC 212.3, correct?

21 A. Yep.

22 Q. To \$2.166 million?

23 A. Yep.

24 Q. All right. And then in your Oregon testimony,
25 your NPC adjustments resulted in a forecast for 2024 of

1 \$2.197 million rounding, correct?

2 A. That's correct.

3 Q. So your Oregon recommendation was higher than
4 your recommendations in this case, right?

5 A. So that's correct. And the big difference is the
6 non-owned wind, or sorry, non-owned reserve issue. So that
7 wasn't included in this testimony. So that was kind of a
8 new issue that I became aware of after filing testimony in
9 Oregon. And so that's the driver of the difference between
10 this. And there are some other differences between this
11 and my direct testimony in this case.

12 Q. And just to be clear, as we look down the number,
13 or excuse me, the name of the adjustments included in the
14 Oregon case, they're very similar. You have an adjustment
15 for the modeling environment of Aurora. You have market
16 caps adjustments. You have DA/RT adjustments. You have
17 the Ozone Transport Rule.

18 A. Right. And one clarification is there's another
19 typo in this testimony that the market caps 95th percentile
20 was actually a different adjustment. So that was -- it was
21 a specific method that the Oregon Commission has used in
22 the past, and so and I clarified that in the hearing in
23 that case.

24 Q. Thank you for that clarification.

25 And I would actually like to ask you about that

1 hearing. So just so the record is clear, there was an
2 evidentiary hearing in that TAM docket on September 7,
3 2023, correct?

4 A. Correct.

5 Q. And during that hearing, you and I did much like
6 we're doing today; isn't that correct? You were
7 cross-examined; is that right?

8 A. I was cross-examined, that's correct.

9 Q. Okay. Now if we could turn to Rocky Mountain
10 Power Exhibit 13.7.

11 A. Okay.

12 Q. And this exhibit is an excerpt from that hearing,
13 and it's an excerpt that is the entirety of your
14 cross-examination testimony.

15 A. Okay.

16 Q. Now, during that cross-examination, you and I
17 discussed your DA/RT adjustments, correct?

18 A. Correct.

19 Q. And if we could turn to page 26 of that exhibit,
20 beginning on line 3, there's a question that says, "Just to
21 be clear, though, your recommendation is based on modeling
22 results that we are describing that, if I'm understanding
23 correctly, you are admitting are erroneous or unreliable;
24 is that correct?"

25 And your answer was, "No, no, I think -- what?"

1 Well, I actually don't know." Do you see that?

2 A. Yeah. So and then I go on to explain that I need
3 to go back and double-check what was happening. So this
4 was a specific issue in the Oregon TAM case, not completely
5 unrelated to this case in which some of the sales,
6 purchases and sales in my NPC forecast were being --
7 dollars were being inflated. It had no impact on overall
8 NPC. And so I did go back and check what was causing that.
9 And in this case in our errata, which I don't know the
10 exact date that it was filed, we made a correction to make
11 sure that that was -- to correct that to eliminate those
12 sales -- purchase and sales values.

13 Q. And just to be clear, you never corrected your
14 Oregon testimony, did you?

15 A. No, we didn't. I mean, it was after the hearing.
16 So we did not correct that.

17 Q. And just to be clear, while the Climate
18 Commitment Act issues you described in your summary were
19 litigated in that case, the Oregon Commission also approved
20 the baseline net power costs that would be used for 2024 in
21 that case as well, correct?

22 A. So in that case there was a settlement. It was
23 with Rocky Mountain Power or PacifiCorp, also Rocky
24 Mountain Power. And all of the parties except for AWEC,
25 the customer group that I represent, and in that settlement

1 PacifiCorp agreed to reduce Oregon-allocated net power
2 costs by approximately \$18 million, and that included the
3 effects of removing the Utah Ozone Transport Rules. And on
4 a total-Company basis, if my recollection is correct, that
5 resulted in a net power cost of \$2.46 billion, and that did
6 not include the impacts of the CCA, which we discussed the
7 Oregon Commission ultimately declined to approve. And so
8 that reduced that forecast down to approximately 1, or
9 sorry, approximately 2.40 billion.

10 And then another thing to point out is that in
11 net power costs in Oregon, the Rolling Hills wind plant is
12 not included, and that's an approximate 10 to \$20 million
13 difference between the NPC in Wyoming and the NPC in
14 Oregon.

15 And so to compare sort of that outcome in the
16 stipulation to this case, we would be looking at a 2.38 to
17 \$2.39 billion net power cost. And recognizing there's lots
18 of give and take that goes into that.

19 And ultimately the Commission in the Oregon case,
20 they didn't decide really on any of the issues. They just
21 accepted the stipulation and found it to be reasonable. So
22 I think that's sort of the crosswalk between that case and
23 this case.

24 Q. I appreciate that you're acknowledging the Oregon
25 net power costs are higher than your recommendation here.

1 But just to confirm, AWEC, the Alliance of Western Energy
2 Consumers, challenged the stipulation, and according to the
3 order, did so specifically based on your DA/RT adjustment
4 recommendation; isn't that correct?

5 A. Right.

6 Q. If you'd like, you can turn to page 5 of the
7 order, which is WIEC Exhibit 241.

8 A. So that I think is generally correct. So the --
9 I guess the nature of the opposition to the settlement was
10 that it didn't -- it included part of the modeling change
11 that we discussed earlier, and we didn't think that that
12 was reasonable in light of the way that the Oregon update
13 process works as well as changes to the market caps.

14 And so -- and I wasn't involved in sort of
15 contesting that settlement, but in terms of opposing it,
16 you know, those were our issues. And, of course, the other
17 parties, you know, were willing to sort of negotiate on
18 those issues. But from my perspective, you know,
19 introducing that new DA/RT modeling adjustment in the
20 middle of the case wasn't something that I was comfortable
21 supporting or nor my customers.

22 Q. And just to be clear, I think you already said
23 this, but the Commission did not adopt any of your
24 adjustments in that TAM, correct?

25 A. Sorry. The Commission didn't decide on any of

1 the adjustments. They just found that the stipulation was
2 reasonable. So they didn't consider any of the merits of
3 those adjustments.

4 Q. Now, let's turn -- I just have a few more
5 questions on the Climate Commitment Act. Now, in this case
6 you recommend that all of the cap and invest costs
7 associated with the Climate Commitment Act should be situs
8 assigned to the Company's Washington customers, correct?

9 A. Not necessarily. So, I mean, I think from this
10 case we're just looking at it from Wyoming's perspective.
11 It's a complicated issue, and at least from Wyoming's
12 perspective, given that Washington state receives, you
13 know, free allowances for their customers, we don't think
14 that Wyoming customers should have to pay for that policy.

15 Now, I think as far as how we deal with that
16 going forward, especially in Washington and within the
17 broader multistate process, is I think something that we
18 really need to consider.

19 And in Washington, I filed testimony on behalf of
20 a customer group there, AWEC also, and I pointed out to the
21 Commission that we need to come to figure out a solution to
22 this problem because it's not workable for Wyoming. It's
23 not workable for the Company. It's not workable for the
24 customers, and so there needs to be some solution. But for
25 this case today, I think the decision really has to be that

1 it's not included in rates.

2 Q. And just to be clear, in that Washington
3 testimony, you did not recommend that Washington customers
4 pay the cost of the Climate Commitment Act, did you?

5 A. So I did not propose a situs assignment-type
6 adjustment in that case. But I did recommend that the
7 Commission come to the multistate process and come up with
8 a solution for the Company and for customers in the other
9 states.

10 Q. And the specific solution you recommended was
11 that Washington pursue inclusion of all of the costs and
12 benefits of Chehalis exclusively of Washington rates; isn't
13 that the recommendation you made in your Washington
14 testimony?

15 A. I'm not sure that I said it that way. But I
16 did -- I do think that one possible option is for
17 Washington to sort of take full -- take on 100 percent of
18 Chehalis.

19 I think it's a complicated issue because, you
20 know, sort of carving a single resource out of customer
21 rates gets very complicated very quickly, and so I think
22 that's one possible solution. It's not the only solution.
23 But at the end of the day, we really should have been
24 having these conversations a year ago or two years ago when
25 this legislation was coming out, because trying to deal

1 with this after the fact, it puts really everyone, the
2 Company, the Commission in a very difficult place.

3 Q. And just to be clear, your recommendation in this
4 case is not to remove Chehalis from Wyoming rates, correct?
5 In fact, WIEC opposes that position; isn't that true?

6 A. Right. Yeah, so, yeah, we don't think --
7 wouldn't think it would be appropriate to remove it, remove
8 it from rates.

9 Q. And in your Oregon testimony that we were just
10 discussing in the transition adjustment mechanism docket,
11 you also didn't recommend situs assignment to Washington of
12 costs resulting from the CCA, correct?

13 A. So my -- yeah, so my testimony in Oregon was like
14 this testimony focused more on sort of the -- sort of the
15 discriminatory nature of the Cap and Invest Program and not
16 necessarily on the multistate process, interjurisdictional
17 allocation issues.

18 The Commission in Oregon, however, was very clear
19 about how that should be done and that it should be situs
20 assigned and so right. And the Oregon staff as well made
21 that recommendation. But that wasn't specifically in my
22 testimony. I talked about mostly the discriminatory
23 issues.

24 Q. Now, Mr. Mullins, in your summary today, you
25 said -- and I'm going to try to quote it, although I'm sure

1 I'm paraphrasing, that the CCA is not a tax. It's a
2 policy. Do you recall that language in your summary?

3 A. I do.

4 Q. Now, if you could turn to Exhibit 21, please.
5 And, again, this was testimony that you filed in that TAM
6 docket. And if we could go to page 14 of that testimony.
7 Or excuse me, 14 of the exhibit.

8 A. Okay.

9 Q. Now, you're discussing the CCA on this page of
10 your testimony. And on line 9, you specifically refer to
11 it as a generation tax. Isn't that correct?

12 A. So this is a general statement. So I say,
13 "Complex legal issues arise with respect to the imposition
14 of generation taxes and regulations that impact interstate
15 commerce." And then I go on to state that these issues
16 will not be addressed here.

17 And so basically what I'm saying here is that
18 we're going to address these issues in briefing. And, you
19 know, I'm not a, you know, constitutional law expert by any
20 means, but I do understand that there are differences
21 between taxes and regulations, and so I think that's what
22 I'm saying here is taxes and regulations, not necessarily
23 referring to the CCA as a tax per se.

24 MR. LOWNEY: All right. Thank you. I have
25 no further questions.

1 MR. WILLIAMS: Thank you.

2 Miss Monahan, do you have questions of this
3 witness?

4 MS. MONAHAN: No questions. Thank you.

5 MR. WILLIAMS: I'm assuming no raised hands
6 from Senator Case or Mr. Flege.

7 MR. PHETTEPLACE: There are none.

8 MR. WILLIAMS: Miss Hamilton, do you have
9 questions?

10 MS. HAMILTON: No questions. Thank you.

11 MR. WILLIAMS: Mr. Petrisin.

12 MR. PETRISIN: Yes, sir.

13 MR. WILLIAMS: You do. Mr. Petrisin, we'll
14 pick up with you after lunch. We'll take a recess now.
15 We'll reconvene at 2 p.m. this afternoon. The Commission
16 is convening in open meeting at 1:30. So enjoy your extra
17 long lunch, although some of you from Rocky Mountain Power
18 will need to be here at 1:30 for the open meeting.

19 (Hearing proceedings recessed

20 11:44 a.m. to 2:00 p.m.)

21 MR. WILLIAMS: Good afternoon. It's 2 p.m.
22 We are back.

23 Mr. Petrisin, you had questions for Mr. Mullins?

24 MR. PETRISIN: Yes, sir.

25

1 EXAMINATION BY THE COMMISSION STAFF

2 Q. (BY MR. PETRISIN) Hello, Mr. Mullins.

3 A. Hello.

4 Q. Were you listening to the questioning of
5 Mr. Mitchell on Friday, October 27 2023?

6 A. I was not.

7 Q. I'll get you up to date. During that
8 questioning, Chairman Throne asked a question about the
9 system balancing impact of adjustments. Mr. Mitchell began
10 his answer as such: "I'll try my best, Chair. So I'll
11 first say that the line item titled 'System Balancing
12 Impact of Adjustments' is unnecessary and irrelevant to the
13 net power cost proposal and unnecessary and irrelevant to
14 the net power cost impacts of the various changes. It's
15 purely an accounting entry to help the reader, and I guess
16 in some cases it confuses the reader." Would you agree
17 with that statement?

18 A. Maybe parts of it. So the system balancing
19 adjustment is -- it's really the difference between the sum
20 of the individual adjustments and the total NPC that they
21 calculated. And in their case, I think I mentioned this
22 earlier, but they kind of started with the end results,
23 kind of the end study, and actually worked backwards to try
24 to figure out the impact of most of the changes that they
25 made.

1 But by doing that, you know, there were impacts
2 that either were offsetting and that impacted each other
3 that weren't, you know, properly, I think, documented in
4 that approach. So I think if you're seeing a system
5 balancing adjustment that large, it would mean that some of
6 those adjustments or the impacts are not being accurately
7 depicted. And so that's why I went through sort of a
8 sequential study is to do a calculation where the actual
9 impacts are more accurately shown.

10 Q. That actually answered my second question. Thank
11 you.

12 A. Okay. Thank you.

13 MR. WILLIAMS: Commissioner Robinson.

14 COMMISSIONER ROBINSON: No questions.

15 Thank you.

16 MR. WILLIAMS: Deputy Chair.

17 DEPUTY CHAIRMAN PETRIE: Thank you.

18 EXAMINATION BY THE COMMISSION

19 Q. (BY DEPUTY CHAIRMAN PETRIE) Mr. Mullins, are you
20 suggesting that Rocky Mountain Power could or should ignore
21 any reserve obligations that it currently has or has in the
22 future?

23 A. I'm not. So my recommendation is primarily on
24 the impact to net power costs associated with those
25 reserves and comparing the impact and the costs that FERC

1 allows to be recovered and the costs included in the Aurora
2 model. So we're not saying that they shouldn't or won't be
3 holding those reserves.

4 Q. And then regarding the discussion of the phantom
5 tax, so-called phantom tax argument, and the Company has
6 strongly suggested that this has been discredited by both
7 the Federal Energy Regulatory Commission and the NRII. And
8 so my question is can you distinguish the situation that we
9 face here in this general rate case from what I take is the
10 general conceptual objections to that treatment that you
11 propose that the Company has pointed out in the literature?

12 A. Yeah, absolutely. So the concept of a phantom
13 tax is it's implying that there are taxes that the utility
14 is recovering that are never paid. And so that's not what
15 I have proposed, and if my testimony came off that way, it
16 wasn't intended to mean that.

17 The issue here is it's really more of a timing
18 issue. So whether you use normalization or flow-through
19 accounting over, you know, the period of time the utility
20 is going to collect all of the taxes that it pays out under
21 either method, it's just whether you spread out those tax
22 benefits of accelerated depreciation over the life of a
23 resource or if you recognize them when they are received.
24 And I say accelerated depreciation because that's probably
25 the principal driver of the deferred taxes and the

1 difference.

2 And so one of the reasons why that makes sense is
3 those tax benefits occur in the early years of a resource's
4 life, and those are the years when the resource is actually
5 more expensive. So while it's true that later in that
6 resource's life customers will be benefiting from that
7 resource, the cost then is otherwise smaller because the
8 plant would have depreciated.

9 So doing it this way I think is appropriate, and
10 it -- I guess there's also this issue of whether it's a
11 stable calculation, whether it might vary year to year, and
12 that -- you know, for purposes of ratemaking, we're dealing
13 with normalized revenue requirement. And so to the extent
14 that, you know, like major plant goes into service, that's
15 going to add lot of costs into revenue requirement. But
16 then there's also going to be those tax benefits to offset
17 that early cost. And so over time that benefits
18 ratepayers, I think, at least temporally so that it's
19 allocating that cost fairly.

20 Q. Let me see if I understand that. Are you
21 suggesting that while in early years there would be an
22 advantage to then current customers, the effects of the
23 depreciation of the plant would balance that in the later
24 years of that capital's service life or --

25 A. Yeah.

1 Q. -- depreciation life?

2 A. Yeah, so over time it will result in slightly
3 lower costs in the early years when that plant balance is
4 high and ratepayers are paying more, but in the later
5 years, there won't be that benefit when the plant balance
6 is otherwise lower. And, of course, in that later period
7 there will be new capital additions being made, and so
8 those customers will benefit from the new capital additions
9 just as the earlier customers benefitted from the capital
10 additions that were made at that time.

11 DEPUTY CHAIRMAN PETRIE: Thank you.

12 MR. WILLIAMS: Chairman.

13 CHAIRMAN THRONE: Thank you, Mr. Williams.

14 EXAMINATION BY THE COMMISSION

15 Q. (BY CHAIRMAN THRONE) Good afternoon, Mr.
16 Mullins.

17 A. Good afternoon.

18 Q. Nice to see you here and not some weird hour of
19 the day.

20 A. I do appreciate the chance to be here.

21 Q. As you began your testimony, you made some
22 general comments about the Aurora model, and I want to make
23 sure I heard them correctly. So I believe you stated that
24 you have been using the Aurora model since about 2014?

25 A. Yeah.

1 Q. And then you went on to say that it's different
2 than the GRID model, and the Aurora is not really designed
3 for the purposes that it's being used for here?

4 A. Yeah.

5 Q. I also heard you say that you're not aware of any
6 other utility in the West using it in the same way as Rocky
7 Mountain Power is.

8 A. Yeah.

9 Q. So I heard all of those things correctly?

10 A. Yeah. Would you like me to expand on those?

11 Q. Sure.

12 A. Yeah, absolutely. So my focus and the customers
13 I represent are predominantly in the West, so that's why I
14 mentioned the West there. And there are many utilities,
15 particularly in the Northwest, that have used Aurora for a
16 long time. So Aurora was actually developed by a -- some
17 former employees of Portland General Electric Company.
18 They went off, and they developed the software, and then
19 companies like Avista and Puget Sound Energy, Idaho Power,
20 they all started using this for price forecasting and for
21 ratemaking purposes.

22 So in the -- the way that the Aurora model was
23 originally developed, it was a -- it's a WECC-wide model.
24 You know, have all of the resources for every utility in
25 the WECC and all of the loads in the WECC, and there will

1 be particular, you know, market zones, and it will figure
2 out, based on the generation stack, what the relative --
3 the relationship between the loads and the generation
4 resources are. And based on the marginal generator in that
5 stack, we'll say that this is the market price for this
6 particular market area.

7 And so it's a regionwide dispatch, and utilities
8 like Avista were using that regionwide dispatch and saying
9 these are our specific resources in that regionwide
10 dispatch, and so this is how they would have dispatched in
11 that total portfolio.

12 And so, yeah, so I've reviewed those for Idaho
13 Power, Avista, Puget Sound Energy. Portland General
14 actually is a different power cost model, but they do use
15 the Aurora model for price forecasting.

16 So the -- right. So PacifiCorp in -- I think it
17 was maybe around 2013ish actually underwent a process
18 through Washington to try to use the Aurora model to
19 forecast power costs. They were directed by the Washington
20 Commission, which was familiar with Aurora to do this. And
21 at the end of that process, they were unable to get that
22 regionwide dispatch to do the same things as the GRID model
23 was doing.

24 And a lot of it has to do with the complications
25 of PacifiCorp's transmission system as well as the fact

1 that the Aurora model, it doesn't -- it doesn't have an
2 ability to do off-system sales. So the GRID model, it
3 included off-system market sales as one of the things that
4 went into the optimization. So the Aurora model didn't do
5 that.

6 And what PacifiCorp has done in this new model is
7 it's actually quite a good sort of technique, but they've
8 tried to simulate these off-system sales using loads and
9 resources that offset those loads. So it's sort of this
10 resource and then offset kind of concept. And it's a good
11 technique, but I'm not so sure that all of the effects of
12 that have been ironed out, and so there may -- some of the
13 things I've seen in Aurora make me question how that's
14 working.

15 At the end of the day, I think, you know, it's
16 besides that contingency reserve issue that I noted, I
17 think I'm comfortable with kind of the forecast results,
18 but I think going forward there might be some refinements
19 that could be made.

20 Q. And going back to the system balancing
21 adjustment, I think there was a follow-up question that I
22 asked Mr. Mitchell, and I essentially asked him, as I
23 recall, is if you're doing those deductions adjustments
24 sequentially, is there a risk that you're double-counting,
25 and I believe he responded that he agreed with me.

1 So is that the reason for the system adjustment,
2 in your opinion, is to avoid double-counting?

3 A. Well, it can -- it can -- you know, two
4 adjustments can amplify each other. And this was in the
5 PGE case that I filed testimony in earlier this year where
6 there was one adjustment for heat rates and another
7 adjustment for the unit capacities. And when you looked at
8 them in isolation, they were actually smaller than the
9 combined whole.

10 And so because of that, the total impact of when
11 I combined them was larger, and so I didn't want to give
12 the impression that they were larger than they actually
13 were, which is why I had done it sequentially.

14 But if it's done sequentially, you could never --
15 it could never really -- I shouldn't say never, but usually
16 you won't see it double-counting things. So if you do it
17 as a one-off study where you're just starting from the base
18 and making many changes and then doing the system balancing
19 adjustment in the end, there is the possibility that two
20 adjustments can address the same costs, and so you're
21 double-counting those adjustments.

22 So like, for example, when they sort of
23 criticized my testimony on this, they said, oh, if you
24 do -- PacifiCorp or RMP said, "Oh, if you run Mr. Mullins'
25 adjustments in the same way, it would result in a big

1 system balancing adjustment."

2 Well, the reason for that was because the two
3 different DA/RT adjustments that I had performed were
4 overlapping. So if you go -- if you go back to the average
5 or just simply tie to the average DA/RT impacts
6 historically or if you reject the -- it implicitly rejects
7 the change that was made in the July Update. So both of
8 those adjustments would have captured the same costs. So
9 if you don't do one and then the other, it's going to
10 inaccurately show those adjustments.

11 So there is kind of some judgment involved in how
12 you present those, but in the bottom line you do want to,
13 you know, minimize what that system balancing adjustment is
14 so that you can explain everything that's happening in the
15 study. And it might mean, for example -- and I've seen
16 this done in the past. You might do a hybrid between the
17 two. So you might say, "All right, so we're going to do
18 market prices first because that impacts a lot of things,
19 and then we're going to do these one-off runs from a study
20 that includes market prices."

21 So there's no like one right way to do it, but if
22 you're seeing a large discrepancy, it means that there's
23 something you need to look into.

24 Q. Okay. Thank you.

25 And I think I have one final question about the

1 reserves. So is it your testimony that the Aurora
2 calculation is overpricing those reserves for purposes of
3 net power costs, if I'm not oversimplifying too much?

4 A. Yeah. No, that's -- I think that's actually a
5 good question. So, in part, so it's definitely overpricing
6 contingency reserves because of sort of that error that I
7 discussed in my intro where you can either toggle off the
8 reserves or you can remove the resources.

9 And I think it's pretty apparent from the July
10 Update that there was a correction to contingency reserves,
11 and that actually increased net power costs by \$63 million
12 compared to I think it's about \$5 million in revenues for
13 all contingency reserves. So there's a really big
14 discrepancy there.

15 You know, for the remaining costs of reserves,
16 you know, I think that getting reserves right in these
17 models is actually very difficult. And so I think that the
18 Aurora model probably does overvalue those reserves based
19 on the costs relative to the revenues. But at the end of
20 the day, reserves are very expensive. And if -- you know,
21 if there is an opportunity cost associated with those
22 reserves, I'm not sure why Wyoming customers have to pay
23 that opportunity cost.

24 CHAIRMAN THRONE: Thank you.

25 THE WITNESS: Thanks.

1 DEPUTY CHAIRMAN PETRIE: That's all.

2 MR. WILLIAMS: Mr. Nelson, do you have

3 redirect?

4 MR. NELSON: Yes.

5 REDIRECT EXAMINATION

6 Q. (BY MR. NELSON) Mr. Mullins, just a couple of
7 questions for you from the cross-examination.

8 Okay. Can you please open Exhibit Number 37.

9 A. Okay.

10 Q. Do you recall a series of questions that you
11 discussed with Mr. Lowney regarding the tax issue and what
12 has been -- what was described in this Exhibit 37 as the
13 phantom tax argument? Do you see that?

14 A. I do.

15 Q. Do you recall that? Sorry.

16 A. I do.

17 Q. Okay. I want to call your attention to page 6 of
18 that document.

19 A. Okay.

20 Q. Okay. And I want to focus on the discussion here
21 on page toward the bottom. Do you see there where it has a
22 sentence that says, "The fundamental fallacy inherent in
23 the phantom tax argument has been succinctly stated by the
24 FERC"? Do you see that, sir?

25 A. I do.

1 Q. So we're going to go through these two paragraphs
2 here real quick, and then I want to talk about how this
3 discussion relates to your testimony.

4 So the document says, "A final important concept
5 relating to the issue of timing differences and interperiod
6 tax allocation is that of continual tax deferral. This is
7 associated with the composite effects over time of a
8 combination of timing differences affecting a company. A
9 continual tax deferral arises when, over time, the total
10 tax benefit associated with new timing differences equals
11 or exceeds the total value of the reversals occurring from
12 earlier timing differences. As a result, under a
13 normalization policy, a positive balance of accumulated
14 deferred taxes reflecting the collection of more taxes in
15 rates that have been paid by the Company could exist into
16 the foreseeable future." Do you see that?

17 A. I do.

18 Q. Does that discussion here -- when you answered
19 Mr. Lowney and other questions and spoke to a concern about
20 the timing differences raised between the flow-through and
21 normalization method, does that paragraph capture what you
22 were referring to?

23 A. Yeah, that's right. So over time, as new capital
24 is added using the normalization method, the tax, deferred
25 tax balances continue to grow over time and don't reverse.

1 Q. And is that dynamic driven when the utility in
2 question is increasing its rate base at a pace in excess of
3 the amount that's being depreciated? Is that correct?

4 A. That is correct. And for most utilities and
5 PacifiCorp in particular that's the case.

6 Q. In going forward, Mr. Mullins, do you
7 anticipate -- based on what we know about PacifiCorp's
8 future investment plans in transmission and generation,
9 would you expect for the foreseeable future PacifiCorp's
10 rate base to continue to grow year over year?

11 A. I would.

12 Q. All right. So let's look at this next paragraph
13 here where the FERC is explaining this. It says,
14 "Continual tax deferrals are often referred to by the
15 misnomer 'permanent tax savings.' This term has the
16 connotation that taxes are not only deferred but are also
17 somehow permanently forgiven. This is inaccurate.
18 Regardless of the number of individual timing differences
19 affecting a given utility, each such timing difference will
20 reverse so that, over the life of the transaction, the
21 total amount of the transaction recognized for ratemaking
22 will equal the total amount recognized for tax purposes.
23 Deferred taxes associated with each timing difference are,
24 in fact, recognized when revenues associated with the
25 transaction are recovered, whether or not the reversals of

1 an initial timing difference are replaced by new timing
2 differences of the same or larger magnitude." Do you see
3 that?

4 A. I do.

5 Q. Was it your intention in your testimony to claim
6 that the taxes that you're analyzing were permanently
7 forgiven or otherwise never paid?

8 A. Absolutely not. So, yeah, if I had given that
9 impression, that was not my intention. So over time, under
10 either method, all of the taxes paid by customers will be
11 paid by the utility. It's just a matter of when those
12 taxes get paid by the customers and whether they are
13 loaning money to the Company.

14 Q. Okay. Mr. Lowney also asked you a series of
15 questions in the discussion about the DA/RT adjustment that
16 asked you to talk about the settlement in the recent Oregon
17 TAM or T-A-M case that you were involved in. Do you recall
18 that series of questions?

19 A. I do.

20 Q. Okay. One of the things that I don't know was
21 made clear through that questions was, as I understood your
22 testimony, there was an adjustment proposed -- or excuse
23 me, an adjustment that was part of that settlement of \$18
24 million total-Company to the baseline net power cost; is
25 that correct?

1 A. Correct.

2 Q. Okay. And can you please describe whether that
3 \$18 million was calculated by the stipulation accepting a
4 specific collection of adjustments or was calculated in
5 what has been called sometimes a black box approach where
6 there was a number that was agreed to without accepting or
7 rejecting any specific adjustment?

8 A. So that's correct. So it was a black box
9 adjustment, and it didn't address any specific issues, and
10 so when the Oregon Commission approved that settlement,
11 they didn't discuss or evaluate the merits of any
12 particular issue in the case.

13 Q. So in that settlement, although your client was
14 not a party to that settlement, is it fair to say that that
15 settlement captured at least some of the value of the
16 adjustments that you recommended in Oregon without
17 specifically accepting or rejecting any of them in
18 particular?

19 A. Yeah, so in Oregon, the Oregon staff, they
20 proposed several of the same adjustments that I had
21 proposed, including rejecting the DA/RT method change and
22 market caps adjustment. So when they accepted that black
23 box, it was presumably in consideration of some of those
24 same adjustments.

25 Q. Okay. In the questioning from Chairman Throne,

1 do you recall a discussion about sort of the origin and
2 history of the Aurora model?

3 A. Yes.

4 Q. In that discussion, at one point you used the
5 word "WECC" or "WECC-wide." Do you recall that?

6 A. Yes.

7 Q. Can you define just for the record what WECC is?

8 A. It's the Western Electricity Coordinating
9 Council. So that's the interconnected region in the
10 western United States for all of the balancing areas in
11 that area.

12 MR. NELSON: Thank you very much.

13 I have no further questions of this witness.

14 MR. WILLIAMS: Mr. Mullins, you're excused.

15 THE WITNESS: Thank you.

16 MR. WILLIAMS: Would WIEC like to call its
17 next witness?

18 MR. NELSON: We would. And Miss King will
19 do so.

20 MS. KING: Thank you. WIEC calls Mr. David
21 Garrett.

22 MR. WILLIAMS: Good afternoon, Mr. Garrett.

23 THE WITNESS: Good afternoon.

24 MR. WILLIAMS: Would you raise your right
25 hand, please.