JULY 31 QBR TRANSCRIPT

SLIDE 2 – INTRODUCTION

Scott Simms: Hello, and welcome to the third Quarterly Business Review of fiscal year 2018. I'm Scott Simms, director of communications here at BPA.

We really appreciate you making time for this forum today. Before we get started, I want to run through a few reminders for today's meeting.

This QBR presentation is being shared via WebEx. The link is available on our event calendar, but if you're having trouble accessing WebEx, the slide deck is also available at bpa.gov/goto/QBR. That's bpa.gov/goto/QBR.

Questions can be submitted at any time today, but they will not be answered until the presentation is complete. To submit a question, click the "chat" button on the upper-right-hand side of your screen, enter your question, and press "send." Your questions will be sent to the BPA host.

SLIDE 3 - AGENDA

So, let's get started. Today, Deputy Administrator Dan James will start with his state of the business, covering Integrated Program Review updates and a BP-20 rate preview. Then, senior executives from Finance, Power and Transmission will provide updates on the agency's financial and operational performance.

It's now my pleasure to turn it over to Dan James.

SLIDE 4 – STATE OF THE BUSINESS

DAN JAMES: Good morning, and welcome to the third quarter QBR. I'm excited to share the state of the business with you today in Elliot's absence. He's out on vacation this week with his family, and he will be back to share our year-end results with you in November.

SLIDE 5 – SAFETY

At the top of our list of Key Performance Indicators is safety, which we are embedding into everything that we do. Our safety KPI looks at incident frequency rate, an industry-standard measure.

Slips, trips and falls continue to be our most frequent issue – not just in the field, but in our offices. Cuts and lacerations contributed to about one-third of our injuries for the quarter.

In Q3, we continued our efforts to increase safety awareness and engagement among employees with our annual Stand up for Safety event. That's a week of activities aimed at reducing incidents and injuries at work, at home and on the go.

We're not pleased with where we are, and we certainly want to see these numbers go down in Q4.

SLIDE 6 – INTEGRATED PROGRAM REVIEW

I'd like to spend the rest of my time on the 2018 Integrated Program Review. This is the first IPR since we released our strategic plan in January. In that plan, we committed to improving our cost management discipline, and this was the first test of our ability to deliver. And I'm happy to report that we rose to the challenge.

SLIDE 7 – BENDING THE COST CURVE

We went into this IPR with the goal of bending the cost curve by slowing or eliminating the trend of increases in our program spending levels, which we recognize is unsustainable.

In this IPR, we met our strategic cost-management objective by keeping program costs flat compared to BP-18.

Power Services proposed an expense reduction of $6 million a year, compared to BP-18 spending levels. We appreciate the collaboration of our generating partners, who proposed to absorb the rate of inflation for operations and maintenance programs. Internally, we continue to lower costs through savings on labor and service contracts.

On the capital side, Power proposes to maintain its ramp to a $300-million annual program to increase power production and reliability.

Transmission Services proposed to increase costs by $3 million a year, compared to BP-18 spending levels. While this is significantly below the rate of inflation, Transmission is looking for additional reductions to get to BP-18 levels by the end of this IPR. Expenses are prioritized to support safety, compliance and market transformation activities, as well as modernize our assets. Transmission took significant steps to offset rising cost pressures such as inflation, filling critical positions and licensing costs. Proposed capital spending is set to achieve safety and high reliability, availability and adequacy standards, and to maximize economic value to the region.

One of the most important changes in this IPR is the new cost-management discipline we are applying. We are changing the way we budget and how we determine what to spend ratepayer money on. We're focusing on the areas that will move our strategic goals forward, and we're getting back to basics. We can't ask others to make budget reductions or raise rates to their customers and members without making some hard choices ourselves.

We've done that. We asked our finance team to evaluate spending through the lens of our strategic plan, and we've begun to land the long-term cost savings they've identified.

More details about BPA's program costs are available in our initial publication and workshop materials that were shared at the meetings in June and on the IPR webpage. We've also posted a number of answers to questions that were asked at the workshops.

SLIDE 8 –GRID MODERNIZATION

During the IPR workshops and comment period, we heard a lot of questions in two specific areas that I'd like to talk about. The first is our Grid Modernization Key Strategic Initiative.

We are providing more information on this initiative as we have it. We have updated the website with project information, and we'll continue to update it as we work through the roadmap and many of the other areas discussed in the June 20th workshop.

We also intend to hold stakeholder meetings as new information is available. We held the first of these meetings on July 24th to share our current assessment of joining the Western energy imbalance ,arket, which is one of many grid modernization projects we've identified.

Please check the initiative's webpage and look for the tech forum meeting announcements as this work moves forward.

SLIDE 9 – BP-20 RATE PREVIEW

The second area we received a lot of questions on is about rates. IPR costs are just one factor, and we understand we are asking customers to weigh in on a variety of other financial processes that may impact rates. We shared a rate preview at last week's rate workshop, and hope that that addresses many of your questions.

I'm going to briefly cover the rate preview, but these results will change with the final IPR and Financial Reserves Policy decisions, as well as the modeling updates and refinements that will be made between now and the release of the initial proposal in November.

With information we currently have, we anticipate a power rate increase of just under 5 percent. This increase assumes initial spending levels with an additional $30 million in cost reductions to the Fish and Wildlife program, as shared in the July 17th workshop. It also assumes that the Financial Reserves Policy, which has not yet been decided, will include a rate reduction, a rate action of $40 million in power rates, which is the equivalent of a $20-million increase in the upcoming rate period.

Another major driver of the rate increase is the end of the rate mitigation measures we took when we moved Energy Efficiency spending from capital to expense. That equates to about a 3-percent increase. In addition, we will see a $7-million increase due to the Residential Exchange Program settlement, but on the flip side, we are seeing lower capital-related costs that help to offset some of these increases.

While we will meet our strategic plan goal of keeping program costs at or below the rate of inflation, we miss an additional internal goal we set for ourselves this rate period to keep the power rate impact at or below the rate of inflation as well. Forecast inflation is near 2.5 percent annually, which means BPA's two-year power rate increase would need to be at least below 5 percent to meet the goal.

Without question, we want to meet or beat inflation, and we are being aggressive to get the power rate increase closer to 4 percent.

SLIDE 10 – BP-20 RATE PREVIEW (CONT.)

The transmission rate increase is expected to be 10 percent, which is what we have been estimating in many of our financial process workshops. The biggest driver here is the updated depreciation study, which you may remember Mary covered in the second quarter QBR. Two other major drivers include increased interest expense and the decision to amortize expenses related to the I-5 Corridor Reinforcement studies over five years, starting in 2020. More information on the amortization was made available last Wednesday in the revenue requirement presentation.

Complete details about the rate preview are available in the BP-20 Rate Case webpage.

SLIDE 11 – IPR NEXT STEPS

Now, I want to close on our next steps. The comment period will close on Thursday. We will consider all comments in combination with more cost-management actions we have identified over the summer. We will issue a closeout report in late September or early October, which will outline our financial spending levels and address your comments. The spending levels will be incorporated into the BP-20 Initial Proposal, which we plan on releasing in November.

SLIDE 12 – FINANCE

Dan James: Now I'd like to hand it off to Mary Hawken, who's going to provide an update on our finances. Mary?

MARY HAWKEN: All right, thank you, Dan, and good morning. Today, I'll be covering the agency's financial position and finance KPIs. Just as we did last quarter, Joel and Richard will then share with you some more detailed breakdowns of Power and Transmission Services expenses and revenues.

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SLIDE 13 – AGENCY NET REVENUES

Slide 13. Just like previous QBRs, we're comparing all of our metrics to the BP-18 Rate Case. This chart shows the net revenues KPI, which is total revenue less total expense.

We currently expect to end fiscal year 2018 with net revenues $397 million above what was anticipated in the rate case, and this is due to both improving revenues and lower expenses. And I want to remind you that while we are, in fact, seeing a better-than-expected year, a large portion of the change from rate case is due to Regional Cooperation Debt savings.

SLIDE 14 – AGENCY FINANCIAL HEALTH

Slide 14. This slide breaks down our net revenues into two more of our KPIs – total revenues and expenses. Total expense, on the left side, includes operations and maintenance, fish and wildlife, energy efficiency, depreciation and interest. And as of the third quarter, we expect to end the year with total expenses $365 million under the rate case projection. This reflects our cost-management actions and also the Regional Cooperation Debt.

Total revenue, on the right side of this chart, is the total of power and transmission revenues. We anticipate ending the year $32 million over what was assumed in the BP-18 Rate Case, and this is driven by better revenues for both business lines, both Power and Transmission, which will be explained later by Joel and Richard.

SLIDE 15 – $70 MILLION INCREASE TO RESERVES

Moving to slide 15. So, before I get to our third-quarter forecast for days cash on hand, I need to take a moment to explain an additional $70 million in power financial reserves for risk that was not included last quarter in our forecast, but we have included it in this quarter's forecast.

The $70 million stems from Regional Cooperation Debt transactions that occurred back on fiscal years 2014 and 2015. Now, for those of you who are interested in more detail about those transactions, you can find more information on the website. It's in the May 2017 QBR materials.

In previous quarters this year, we modeled this $70 million as being used for an additional Treasury payment above our scheduled payment. When, in fact, our 2014 agreement with the region was to use the $70 million for the scheduled Treasury payment. We caught this modeling error after the second quarter this year, and we've made the correction in this forecast that you see today.

I need to take a moment to personally apologize for this error. Regardless of the fact that this error is in the customers' favor, I understand that unplanned changes of this magnitude are frustrating for you, they certainly are for us. We're currently conducting a root cause analysis with our Risk organization to improve our forecasting and to catch potential errors before reserve forecasts are finalized.

SLIDE 16 – DAYS CASH ON HAND

Moving forward to slide 16. Even absent this correction, our days cash on hand has improved. Days cash on hand indicates the number of days BPA can pay its operating expenses based on the amount of financial reserves available.

Power's days cash on hand has increased to a total of 33 days. This is still short of our minimum threshold of 60 days cash on hand, but it's a great improvement from our second quarter forecast and it has eliminated the chance of a CRAC occurring this year. Transmission also saw an improvement since the second quarter.

The overall positive improvement to agency financial reserves has led to an agency reserves outlook of 96 days cash on hand. This is a very important milestone in our Financial Reserves Policy, as 90 days cash on hand is our upper threshold for agency financial reserves and the level at which a reserves distribution clause could trigger.

SLIDE 17 – CRAC AND RDC PROBABILITY

Slide 17. So, a reserves distribution clause, or RDC, occurs of two conditions exist: one, if a business line's financial reserves are over their upper threshold, and two, if the agency's financial reserves are over the upper threshold. The forecast for Transmission's days cash on hand is currently 276 days, that's well above the 120-day upper threshold. If the RDC triggers, the Administrator has discretion over whether and how the additional funds should be used.

We've developed an RDC probability calculation, which is similar to the one you've seen for CRAC probability. Based on our current forecast, we have an 80-percent probability that an RDC will trigger for transmission customers.

Now, the actual determination of an RDC and the amount is based off of accumulated calibrated net revenue, or ACNR. On this slide, you see a ribbon chart that shows the relationship between ACNR for the agency and our reserves for risk. If the RDC were to trigger today, we anticipate it would be $24 million.

BPA will make the final determination if it triggers the RDC in September, along with the Administrator's decision on how to use these additional funds. If there is an RDC, we'll hold a workshop by the end of September to inform you about the calculation and the final decision.

Additional financial details on what I shared today, including more information on the ACNR – accumulated calibrated net revenue – are available in the Quarterly Financial Package published on the Financial Overview webpage.

SLIDE 18 – POWER SERVICES

Mary Hawken: And that's all for my finance update today. Now, I'll turn it over to Senior Vice President of Power Services Joel Cook, who will provide more details on Power Services' financials and initiatives.

Joel Cook: Thank you, Mary, and good morning, everyone. I'm excited to share with you our third quarter results for Power Services. We're starting on page 19.

SLIDE 19 – POWER SERVICES EXPENSE

Over the last three quarters, we've consistently come in under our rate case, and that's mainly due to two things – the cost-management efforts across BPA and our partners, and also the big impact from the Regional Cooperation Debt that Mary mentioned earlier.

I draw your attention to the upper-right-hand chart there, looking at year-to-date numbers, we are $156 million lower than our rate case year-to-date expenses, and we're forecasting to come in at roughly $182 million lower than our total rate case expense forecast by the end of the year.

SLIDE 20 – POWER SERVICES REVENUES

Turning next to Power Services revenues, operating revenues through June have been trending higher than rate case, and that's mainly due to two factors: one, primarily the higher surplus energy sales from the above average water that we've experienced this year, that's somewhat offset by the lower preference loads we've had, but then that has been minimized due to the remarketing of the power that we've had.

I also want to note that revenues from the spill surcharge are also included in the June actuals and the end-of-year revenue forecast.

Again, looking to the upper-right-hand corner there, in year to date, we're $26 million above rate case and forecasts for the end of the year, we're anticipating to be $23 million above rate case for our revenues.

Turning to the next slide, I'm going to discuss – excuse me, before we go there, I just wanted to mention that when you combine the Power revenue's expense and revenue forecast, we're coming in at approximately $403 million, or $79 million greater than the $325 million net revenue target. This strong secondary sales and cost management efforts are key drivers to these gains.

The weather has been good to us this year, and controlling our costs, where possible, has put Power Services in a strong financial position for the remaining part of the year.

I want to take this time to thank everybody for their efforts, both on the cost management and the revenue side.

SLIDE 21 – WATER SUPPLY

Now, turning to water supply. This is a new slide for Power. Three things I'd like to highlight here for you all. One, if you look at the red and black lines, the black lines represents the natural stream flows, or the unregulated flow that we would have experienced from the runoff this year from the January through July period. The red line represents the impact of managing that water with our federal hydro system.

As you can see, we benefited from more water than we would have in the early part of the year, and important to note, we kept water at below flood levels in the May-June runoff period.

The second thing to note on here is that the stream flows peaked earlier than historical averages, so we saw stream flows peak in the May period, rather than more so in the June period. So, not only did we get a lot of water, but it came off very hard at the end of May there.

And then the third thing to point out is what I've mentioned previously, the above average water that we've experienced. So, if you look at the lightest shade of green, you notice that that represents the 50th percentile, and we were a little bit above that for a good part of the year. So, good water has helped our net secondary sales efforts.

SLIDE 22 – HENRY HUB PRICES

Turning to the next slide. Talk a little bit briefly about Henry Hub prices. We saw prices depart from the rate-casefForecast through October and March, and they're largely driven by warmer-than-expected national average weather in October and February. A cold April and a hot May brought gas prices back to our forecast by keeping demand elevated into the beginning of the injection season and building a large storage deficit.

Recent gas NYMEX forward curves are closer to our Henry Hub forecast for the remainder of the year.

SLIDE 23 – MID-C PRICES

Slide 23 shows Mid-C prices, both historical and for the rest of the year. Mid-C prices are above our forecast for the remainder of the year, driven in part by warmer-than-average regional summer outlook, and lower-than-average water supply. These high prices are also being driven by weather conditions in California, coupled with expectations of tighter evening ramp conditions in California.

SLIDE 24 – POWER SERVICES CAPITAL

Moving on to slide 24. This, again, is a new slide for Power. Might look familiar when Richard goes over his slides, but this slide represents capital expenditure and work completed. So, the line graph represents the year-to-date through Q3 amount of capital spending we've had, at $137 million. Although, our forecast for the year was $244 million, we're expecting the end of the year to come in at about $192 million by the end of the year. So, our capital expenditure is going to be far below the planned $244.

The bar charts represent the percent of work planned completed. These are the projects we anticipated to complete in this year. And I should point out that almost all of our projects are multi-year projects, so these bar charts represent those projects that we anticipated to be complete this year.

Looking at Q3, we anticipated 27 projects to complete and we've completed 23 so far this year. Four projects missed their physical completion milestone this quarter largely due to updated project scoping.

Reclamation is underspending significantly form their rate case request, driven largely by challenges to resource the work, project holdups at Grand Coulee Firehouse, work done at Keys Pumping Station are causing under-execution.

For the Corps, they're on track to overspend their rate case request due to acceleration of transformer purchases and installations at the Dalles, turbine and generator work at Ice Harbor, emergency gantry crane work at John Day, and Unit 3 work at Dworshak, as well as station service replacement at McNary.

SLIDE 25 – FEDERAL HYDROPOWER RELIABILITY

Next, we're going to go to the federal hydropower forced outage factor. This key performance metric represents the percentage of hours that fed hydro projects are offline due to unplanned outages. We are well under our target of 5.9 percent for the year, so that's a good thing. The primary thing that has kept us from exceeding that target are outages at The Dalles, Ice Harbor, Lower Monumental, and John Day.

SLIDE 26 – COLUMBIA GENERATING STATION RELIABILITY

Moving on to Columbia Generation Station. This metric represents the percentage of time Columbia Generation is available to serve our demand. Again, we've seen good performance from CGS this year. Despite a few bumps, performance through June has exceeded the target. There were two unplanned outages, one that we reported the last few quarters, and one that occurred in May, however, the length of that outage was short enough not to impact the overall availability factor for Q3.

SLIDE 27 – ENGAGE WITH POWER

Finally, I'd like to turn to the last slide. I'd like to let you know about some important information about upcoming events, where we'd like your feedback. Earlier in the QBR, Dan teased out some potential rate impacts in the upcoming BP-20 Rate Case. The rate case has kicked off, and at the August 8th rate case workshop, we will look forward to customer feedback specifically for how the net secondary revenue credit is determined.

We will also be discussing how rate case mechanisms such as the cost recovery allocation clause and the reserves surcharge will be implemented in the financial reserve policy.

Lastly, two public comment periods are coming up. The Rate Period High-Water Mark comment period is open for BP-20 rate period. This is an important component in determining the forecast quantity of power available to be sold at our tier-one rate, and the net revenue requirements transparency process opens tomorrow.

Before I turn it over to Richard to talk about Transmission, I'd just like to say that from my perspective, we are in good financial position to close out the year. More recently, we've seen some high prices and very hot temperatures, and then we think we have fared well through that period. We look forward to telling you more about what we're working on in coming QBRs.

SLIDE 28 – TRANSMISSION SERVICES

Joel Cook: I'd now like to turn it over to our Senior Vice President of Transmission Services Richard Shaheen.

Richard Shaheen: All right. Thank you, Joel. It's a pleasure to be with everyone here today and to share Transmission's third-quarter results.

I'm going to start my report with Transmission's expenses and revenues, then look at our capital plans, then transmission grid reliability, then wrap up with a few updates and engagement items.

SLIDE 29 – TRANSMISSION SERVICES EXPENSE

Moving to slide 29. Transmission Services expenses.

This format is identical to Power's financial information that Joel just showed, showing the fiscal year and the BP-18 Rate Case spend per month versus our actual expenses per month.

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For the third quarter, consisting of April, May and June, we had actual expenses of $261 million, versus $261 million rate case quarter allocation, staying directly on plan.

Referencing the table in the upper right hand of the chart now. For year-end expenses, our forecast, $7 million higher than rate case due to higher ancillary services and oversupply costs that have some offsetting revenues, and higher depreciation expense.

The higher expenses were partially offset by $19 million in reductions taken in Q2 to help meet BPA's cost-management objective and a decrease in the interest expense forecast.

Year-to-date expenses are at $746 million, versus rate case year-to-date plan of $782 million. Therefore, actuals are $36 million less than planned.

SLIDE 30 – TRANSMISSION SERVICES REVENUES

Moving on to slide 30. Transmission Services revenues.

Revenues are consistently running above monthly rate forecasts. We expect higher revenues to continue for the rest of the year, and anticipate we'll end the year above rate case projections.

For the third quarter, again, actuals are at $284 million, versus a rate case projection of $268 million, resulting in actuals of $16 million higher than projected for the quarter.

Our net revenues were higher due to higher network load than had been assumed. Network load was higher because of the temperature differential and the duration of higher temperatures that were built into the revenue projection.

Again, referencing the table in the upper-right-hand part of this slide. For year end, we're forecasting revenues of $1.078 billion versus a rate case projection of $1.052 billion, therefore year-end actuals of $26 million more than rate case. Year-to-date actual revenues are at $828 million versus rate case year-to-date plan of $794 million, therefore, year-to-date revenues are at $34 million higher than planned.

SLIDE 31 – TRANSMISSION SERVICES CAPITAL

Next, moving to slide 31. Transmission Services capital.

There's actually two things that are depicted on this slide – our capital spend and our work plan progress. Joel did a good job describing the details of how we count our work plan progress. These are actual in-service completions of projects, although many projects span multiple years.

This quarter's end-of-year forecast of capital expenditures is $97 million less than rate case, driven by resource management and outage constraints, as well as non-critical projects being put on hold to accommodate customer and compliance projects.

Over the rate case, Transmission has established a process to regulate the admittance of capital projects into our portfolio and to require formal scoping of substation work. This formal scoping improves our certainty in outcomes, but requires an investment of time.

Similarly, an increase in success projects entering the planning process began in late FY16, and continues to today, which has displaced capital projects for BPA's sustain and expand program. The effect of these factors is that our FY18 capital spend is below rate case.

For year-to-date at the end of Q3, we remain below budgeting goals and have executed more projects in service than actually planned.

One final note. This quarter, Bonneville accepted an offer from its customer, Lower Valley Energy, to build the Hooper Springs Transmission Project in Southeast Idaho. The agreement takes advantage of the best each entity has to offer, which will reduce costs and maintain reliable service to the region, as we continue our flexible, scalable and cost-effective approaches.

SLIDE 32 – TRANSMISSION RELIABILTY – SAIFI

Advancing to slide 32. Transmission reliability - SAIFI.

The system average interruption frequency index, or SAIFI, tracks frequency of unplanned outages. We track it in two forms, both the voltage less than 200 kV part of the grid, and the voltage greater than 200 kV part of the grid. We also have on this chart dashed lines which depict warning levels. These are based on historical performance within the transmission BPA grid, and they are not to exceed levels. Down is good on this chart.

In FY 2018 to date, we maintained stable and good levels in our greater than 200 kV lines, and we improved to an average of 0.47 unplanned outages in our less than 200 kV lines per year.

BPA's reliability overall is improving. These outages are going down from Q1 to Q3. This indicates a better performance, however, part of this improvement may be due to calmer weather.

Recent fire activity has driven some outages, and may impact these numbers by the end of the fiscal year. Fire impact on reliability is closely monitored in Transmission.

Bottom line: BPA is showing improved reliability since the beginning of the year, and our continuous improvement project is investigating outages in order to find their root causes and prevent recurrences.

SLIDE 33 – TRANSMISSION RELIABILTY - SAIDI

Moving on to slide 33. Transmission reliability - SAIDI.

The system average interruption duration index, or SAIDI, tracks duration of unplanned outages. This is a measure of average minutes per outage. As before, we track this in two parts of our grid – the less than 200 kV and the greater than 200 kV.

We also have on this chart dashed lines which depict warning levels. Again, down is good on this chart.

Performance is below limits, and the overall trend is stable. Again, milder weather may be a factor in these measures through Q3, and again, fire activity has the potential for negative impact during Q4, which we continue to closely monitor.

Moving on to my final slide, slide 34.

SLIDE 34 – ENGAGE WITH TRANSMISSION

Moving on to my final slide, slide 34.

I want to give a brief update on a few key topical areas within transmission.

First, Peak Reliability announced on July 18th that they decided to pursue an orderly closure of its reliability coordinator services by December 31, 2019. We're committed to maintain the reliability of the electric grid in the Northwest by working with Peak through this transition period as we select a new reliability coordinator.

We began in January of this year to examine the options available for us for reliability coordinator services, and we'll continue our work to determine which option drives the greatest benefit and value for both BPA and the region going forward, and we'll be holding a customer meeting on August 3rd to discuss this.

Next, at last week's workshop for the TC-20 proceeding, BPA shared its intent to initiate settlement discussions that could lead to settling key issues and allowing us to convert all BPA OATT customers – Open Access Transmission Tariff – to a new common tariff that will help execute elements of booth our Transmission Business Model and our BPA agency strategy.

BPA will be sharing positions on all open issues currently within scope of the TC-20 workshops on August 21st at the final public workshop, followed by a brief comment period before settlement discussions begin September 10th. BPA's proposed new tariff, reflecting its positions on all TC-20 issues, will be posted by early September. If BPA and its transmission customers are unable to reach settlement, then we're expecting to begin the formal 212 hearing process in November.

Next, earlier this month, we announced our intent to conduct a 2019 Cluster Study. This is the first step in evaluating all requests for transmission services through the TSR study – our transmission service request study – and expansion process. The deadline to submit requests for eligibility in the next cluster study is August 31st. The study portion will begin first of the new calendar year.

And, finally, last month, we saw the release of the Montana Renewables Development Action Plan. This report, the result of a process sponsored by our administrator Elliot Mainzer, and Montana's Governor Steve Bullock, was developed in partnership with a group of our regional partners and explores opportunities and barriers of renewables resource development in Montana.

You can find a link to the Montana Renewables Development Action Plan and this recent report on bpa.gov under initiatives, or by clicking the link in the presentation materials for today's QBR. We appreciate all of the participants who worked to make this an effective, informative, and timely process to explore the different aspects of renewable resources development in Montana.

That concludes today's update from the business lines, and I'm going to turn it back over to Scott. Thank you.

SLIDE 35 – PUBLIC PROCESSES

SCOTT SIMMS: Yeah, thank you, Richard, and thanks to all of our presenters today.

Before we take questions, I have a few reminders to share out about upcoming opportunities to engage with BPA. A complete list of our upcoming events and processes are listed at bpa.gov.

SLIDE 36 – PUBLIC PROCESSES

Let's begin with public processes on slide 36.

We recognize that many of you are already engaged in attending meetings on the topics listed here. Timing and details of these meetings are posted on BPA's event calendar.

As Richard mentioned, after Peak announced it will wind down, BPA will remain dedicated to maintaining reliability coordinator services, and will create opportunities for you to engage before we make a decision. That meeting is listed on this slide as August 2.

Both Dan and Joel mentioned BP-20 workshops during their update. We have one scheduled for August 8th and one is tentatively set for August 22nd.

On the transmission side, we have two more TC-20 tariff customer workshops scheduled for August 21 and September 25, and we plan to initiate settlement discussions in early September.

A topic in which many of our stakeholders have an interest is the Columbia River Treaty. The State Department announced a town hall on September 6th that will be held in our rates hearing room in Portland at 5:30 p.m. on September 6th. U.S. Columbia River Treaty Negotiator Jill Smail will provide a general overview of the negotiation. Questions can be submitted in advance to ColumbiaRiverTreaty@state.gov. That's ColumbiaRiverTreaty@state.gov.

Last, but not least, our grid modernization efforts include another public stakeholder meeting on October 11th for those interested in potential EIM participation.

SLIDE 37 – COMMENT PERIODS

Now, let's turn to comment periods on slide 37.

This is a big week for us, as we will close our three comment periods – comments on the Integrated Program Review, Financial Reserves and Leverage policies, and capital financing are all due this Thursday, August 2nd. We're glad to see many comments have already come in, and appreciate that the region and our customers are engaged, because your feedback helps provide us with information we need to make well-informed decisions. We can't do it without your involvement.

We also have two comment periods closing this week. Next Wednesday, the FY 2020 and 2021 Rate Period High-Water Mark closes. These will be used to set power rates in the upcoming BP-20 Rate Case. Next Thursday, a Spar Canyon-Round Valley project comment period closes. We request your comments on an environmental assessment that was completed for that project.

Also, we know many of you are anxious for an update on the Accords, which Elliot covered last QBR. We are looking at extensions of the Accords, and we anticipate having a public comment period on the proposal later in August. We will make sure to update our website and send out communications when these details have been finalized.

More information about these comment periods is available at bpa.gov/comment.

SLIDE 38 – QUESTION AND ANSWER

That concludes the presentation portion of today's QBR. We will now begin answering your questions from those who have submitted during today's presentation.

As a reminder, you can still submit questions by clicking the "chat" button on the upper-right-hand part of your screen. Enter your question, and press "send."

We would just say that so far today, it's a quiet crowd out there.

We have a question from Peter Scanlon: How do the lower-than-projected capital spends translate into expenses?

MARY HAWKEN: You'll see, with lower capital, we'll have lower interest expense on the income statement, and then also lower depreciation.

SCOTT SIMMS: Okay, great. Looks like also we have a flag on the reliability coordinator meeting workshop, just want to make sure that folks see that it is listed as August 3 on bpa.gov, but slide 36 says August 2. And I think Richard Shaheen also said August 3, so we will get that one hammered out and corrected here as soon as possible.

We also have another question about slide 7: What does that represent? Go back to slide 7. This was the schematic for grid modernization – no, that's slide 8. Slide 7, bending the cost curve. This is one of our favorite topics lately here at BPA. Dan, do you want to take that one on?

DAN JAMES: And what was the question?

SCOTT SIMMS: I think the question was: What does the slide actually represent in terms of what are we trying to display in this bending the cost curve slide?

DAN JAMES: That actually shows a decline in our program costs and a percentage of the cost change by rate period. So, what you see there is a decline from BP-10 all the way through BP-18 to the current year, 2018, where we are in the current IPR.

SCOTT SIMMS: Great. Thank you, Dan. We're still waiting for additional questions to be submitted. So, again, you can still submit questions by clicking the "chat" button on the upper-right-hand part of your screen, enter your question, and press "send."

This one looks like it might be coming for the Transmission side: Does BPA plan on leveraging tower assets to provide radio/cell coverage in the Pacific Northwest?

RICHARD SHAHEEN: Well, actually, we currently do that now and we're always entertaining offers of telecom organizations that want to use our facilities, and it could be anywhere from our existing radio towers to our transmission structures to any of our land areas in substations or service centers that they would locate towers. But it is something we currently do and continue to pursue.

SCOTT SIMMS: Thank you, Richard. Another question we have is: How much of power lower costs are from RCD – Regional Cooperation Debt?

JOEL COOK: This is Joel. I believe it's roughly $130 million in savings.

SCOTT SIMMS: Okay. Thank you, Joel. Okay, just waiting for more questions here.

One more reminder. As a reminder, you can still submit questions by clicking the "chat" button on the upper-right-hand part of your screen, enter your question, and press "send."

Okay, we have another one here from Marie Morrison: Could you give an update on the Substation Fire and its impact on BPA transmission assets?

RICHARD SHAHEEN: Well, thus far, we've been quite fortunate that there hasn't been any significant damage to any of our transmission facilities. No damage to any substations or switch yards. There have been a very minimal number of wood structures that were impacted, no impact to any of our steel lattice structures.

We have had a few line outages due to smoke from fires moving underneath our transmission lines, but we continue to have folks staged safely in monitoring the fire's progress and in coordination with our dispatch centers. Thus far, system impact has been minimal. And as I stated, infrastructure damage has been very minimal.

SCOTT SIMMS: I would just say, as a side note on that, The Dalles transmission line maintenance crew, helped by the Olympia line maintenance crew, did a tremendous job out there in the field working in coordination with firefighters. Of course, we do not, ourselves, fight fires, but working in close cooperation with emergency management officials.

RICHARD SHAHEEN: Absolutely. That's true. And there was a fire named the "Substation Fire," although it really had no tie to any of our substations, it just happened to be in visual vicinity of our converter DC station and they chose to name it the Substation Fire because of that. But we've been very fortunate, and hats off to all our crews and dispatch centers and the entire BPA team for keeping watch on the fires and keeping our system safe and reliable.

SCOTT SIMMS: That's a good point. The dispatch folks play a huge role in that as well.

So, another question here is a question from Kevin O'Meara on slide 15 and the $70-million increase in revenues. The question is: What exactly happened? And I think Mary's going to take that one on.

MARY HAWKEN: Yeah, let me try and explain that again. So, it's a $70-million increase in power financial reserves for risk. In our previous forecast, basically, we were overstating our Treasury payment, which is cash leaving the Bonneville Fund.

And what we have done is corrected that. So, this additional $70 million that we had committed to back in 2014 and 2015, we were basically double counting that Treasury payment. We've corrected that, and the result is the $70 million doesn't flow out of the fund, and therefore, the balance is higher in this forecast than it was in the previous forecast.

I hope that helps. I know it's a little complicated. There is some additional information online in the QBR package, and we're happy to talk more if we need to clear that up.

SCOTT SIMMS: Okay, great. Thank you, Mary.

The next question is with regard to slide 17 from Fred Hewitt: On slide 17, how is the potential $24 million in Regional Cooperation orRDC return, and what are the options for allocation that? Mary, do you want to stream that out a little bit better?

MARY HAWKEN: Can you just –

SCOTT SIMMS: Oh, it's a correction, here we go. On slide 17, how is the potential $24 million in RDC return calculated, and what are the options for allocating that? And thank you, Fred, for rewriting that question.

MARY HAWKEN: Yes. So, if you look at slide 17, this ribbon is from our rate case documentation. And if you look at the very top line, it's the accumulated calibrated net revenue, and when we move over to the right in the dark blue, that's where an RDC triggers. And you can see in the box above, our Q3 ACNR forecast is $782 million, which is $24 million into that dark-blue zone. So, that's how that is calculated. So, we're $24 million higher than what was shown in the rate case that moves us into the RDC zone.

And then the options. So, the options were documented in the rate case. The Administrator could choose to pay off additional debt, use it for other sources, or use it in rates, also. So, there's quite a list that the administrator can rely on as he makes his decision in September. And we'll have more of that information at that time.

SCOTT SIMMS: Okay. Great. Thank you, Mary. As additional questions stream in, I do want to make sure to circle back to that reliability coordinator services workshop that we had listed on slide 36. That was listed on that slide as August 2nd. We just got confirmation that it is actually on August 3rd. We will make that correction in our posted materials, but wanted to make sure folks flagged that. The reliability coordinator services workshop is on August 3rd, so we apologize for that error.

Now, let's go back to some questions here. Next question is: Can you explain how transmission reserves are growing more than the increased transmission net revenues? I don't know who wants to take that one on, this is the question from one of our stakeholders here.

MARY HAWKEN: We may have to follow up on that one.

SCOTT SIMMS: Okay. I would just say we have a good approach here on the QBRs. If we can't answer your question today or need to do some follow up, we will be pushing those out via our IPR website.

MARY HAWKEN: Maybe if we could have a little more information on the specific – if there's a certain year or time period the person's looking at, just a little more information on the question.

RICHARD SHAHEEN: Yeah, and it may be a timing issue of forecast versus actuals and when we're seeing the actual reserves change value versus net revenues being reflected in our current budget. So, I think any difference between the two is more related to timing issues than anything else, because the net revenue should, ultimately, match any change in reserves.

SCOTT SIMMS: Okay. Well, let's do this: if we need additional clarity on this, we'll ask the participant to send that question in more detail to communiations@bpa.gov, and that really goes for anyone here who either doesn't want to ask a question on the WebEx, or would like to write a more detailed question to us. Again, it's communications@bpa.gov.

RICHARD SHAHEEN: And a question like that, it might be helpful to know what the individual's looking at, so we can specifically explain the discrepancy.

SCOTT SIMMS: Good point, Richard. Thank you. Okay. Additional questions? So, we currently do not have any other questions, although I have to say this is the most robust line of questions we've received so far in the revised QBR format, so that's great news. We're going to wait for just a moment here to see if there are any other questions being submitted. Otherwise, we're going to go ahead and call it.

SLIDE 41 – THANK YOU

All right, with that, we're going to wrap up our question and answer session. Again, if we're unable to get to your question today or you want to submit a more detailed one, communications@bpa.gov is the place to send that.

Those questions already submitted via today's WebEx do not need to be resubmitted, but if you want to clarify, that would be great. We'll be posting follow-up answers to all these questions on the QBR webpage in the coming weeks, along with a recording of today's meeting.

We really appreciate you listening today. We really appreciate you engaging with us today, and we look forward to you joining us on the November 6th call for our end-of-year QBR.

Thanks, everyone. Have a great day.

SLIDE 42 – FINANCIAL DISCLOSURE