April 30, 2019, QBR TRANSCRIPT

SLIDE 2 – INTRODUCTION

SCOTT SIMMS: Hello, and welcome to the second Quarterly Business Review of 2019. I'm Scott Simms, Director of Communications here at BPA. We appreciate you making time for this forum today. Before we get started, I want to run through a few reminders for this meeting. Today's presentation is being recorded and 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. Let's get started.

SLIDE 3 – AGENDA

Today, administrator Elliot Mainzer will start with a state of the business, and then senior executives from Power, Transmission, Finance and the Business Transformation Office will provide updates on the agency's financial and operational performance.

And with that, let's get started with our administrator, Elliot Mainzer.

SLIDE 4 – STATE OF THE BUSINESS

Thanks, Scott. Good morning, everybody. Thank you for joining us for the call this morning. I'm going to kick off this morning with our top core value at Bonneville, safety.

SLIDE 5 – SAFETY

Our key performance indicator for safety is our incident frequency rate, which is the number of injuries and illnesses per 200,000 hours worked. We actually started this fiscal year with 0 injuries through October and were able to maintain a low incident frequency rate through the first quarter. There was an increase in the second quarter where we ended with an IFR of 0.7. Although this is below the ceiling of 1.1 and significantly lower than we were at this point last year, and certainly it's a positive way to end the first half, there continues to be work to be done here at Bonneville in safety. We continue to have multiple injury and incident reports which lets us know we have to keep our head down and keep working to continue to make progress on this very important issue.

We have a number of initiatives planned for the year to help address some of the more frequent safety issues that we continue to see. These include improving motor vehicle safety, preventing hearing loss, and reducing strains and sprains. So although we continue to evolve and make progress on our safety culture and our safety numbers we need to keep our head down and make progress towards our long-term goal of 0 injuries across our entire enterprise.

SLIDE 6 – FLEXIBLE SPILL AGREEMENT

I'm now going to move into the flexible spill agreement, which is slide 6. As I shared last quarter, Bonneville and its federal partners reached agreement with the Nez Perce Tribe and the states of Washington and Oregon last December on a flexible spring spill operation. Through this agreement, which will be in place while we complete the Columbia River System Operations environmental impact statement process, we're going to learn about spill operations that have previously been untested. I believe this information will inform the development of a longer-term sustainable solution for the management of the Columbia River and I think represents an important milestone in the discussion of river operations.

SLIDE 7 – FLEXIBLE SPILL

Sitting here at the end of April we're now nearly a month into this flexible spill operation. So far our implementation has been going quite smoothly. Our coordination with the Corps of Engineers which, of course operates and maintains the projects, and our joint implementation is going well. We've also been benefiting from the improved lines of communication between all the parties of the agreement and we've been able to effectively resolve issues during these early stages of implementation. I would say while it's still too early to do a meaningful economic analysis of the operations, the implementation itself has gone well. We've been able to operate the system in the fashion we anticipated in our planning activities, and the streamflow conditions we've seen on the river so far have allowed us to increase generation, find markets for that energy on our scheduled hours during most days. I'd say fortunately because of the water condition, system capacity has been more than enough to meet our peak loads even without flexible spill, but of course that dynamic could change under other stream flow conditions, which we'll monitor carefully.

I'd say at the end of the day while there are always unique conditions and operational realities that are not accounted for in planning, our initial impression is that the overall spill operation and the flex spill component are behaving as expected. We're still learning how large swings in spill levels that occur several times a day will impact the hydro system. We'll continue to work with our partners in the region to incorporate our experience this spring into our plans for the spring of 2020 when spill levels are expected to further increase, assuming that Washington and Oregon are able to adjust their water quality standards. So certainly flexible spill I think we're moving in the right direction at this stage.

SLIDE 8 – SPILL SURCHARGE

I'd now like to turn our attention to the spill surcharge. I think as most of you know the spill surcharge is a mechanism to recover costs associated with increased spill and the resulting decreased power generation. The surcharge was originally put in place as a result of a federal court decision ordering increased spill at eight federal dams on the lower Columbia and Snake rivers for 2018 spring fish passage season. The financial impacts of the ruling were unknown in July 2017 when rates for years 2018 and 2019 were set, so we established the spill surcharge.

SLIDE 9 – SPILL SURCHARGE

On April 18, Bonneville hosted a workshop to discuss the details behind the 2019 spill surcharge calculation. Using the same standard rate setting method based on the average of 80-year water conditions the estimated cost for spill in 2019 is $35 million, which is slightly lower than it was in 2018. This assumes the flexible operations which are now in place in the river. After consideration of our various alternatives, I am proposing for Bonneville to offset the entire spill cost in 2019 through Fish and Wildlife cost reductions, and as a result customers will not see a spill surcharge in 2019. Consistent with the Bonneville strategic plan, we're taking a more disciplined approach to managing our Fish and Wildlife program costs, and we've made a lot of progress reflected in this development.

Now, BPA has already worked with Fish and Wildlife project partners to navigate adjustments to the costs and reset the budget for fiscal year 2019. Budget reductions are occurring through efficiencies and reduced contract budgets that have already been agreed upon. Bonneville is not proposing further program or project costs this year. We're accepting comments from the proposed spill surcharge through this Thursday, May 2, so I encourage you to get your comments in if you have them. Our plan is to issue a final decision on the surcharge on May 16. Next year we will not have a surcharge, as the spill costs are already modeled into the BP-20 rate case.

Before I hand it over to Joel Cook, I'd like to briefly highlight a few areas that I will be focused on for the rest of this fiscal year. First, I remain acutely attentive to the financial reserves review process that kicked off in February. As I've said back in February, the magnitude and duration of this error is concerning to me and requires prompt and effective resolution. I know that we have received input from many of you about the reserves review process, and Michelle Manary will be providing an update on where we are later during the call this morning. At this point I want to reaffirm my commitment to remaining transparent throughout the process and we will propose corrections to address the error as expeditiously as possible consistent with our rate case timelines. I have confidence that Michelle will be able to lead us through this process and appreciate her diligence to ensure that all of our underlying data is correct and accurate as we move forward with implementing elements of the strategic plan to strengthen our financial health.

The second area I will be focused on throughout the balance of this year is our process to decide whether or not to join the Western Energy Imbalance Market. This summer Bonneville expects to issue a decision document on BPA's intent to enter into an EIM implementation agreement with the California Independent System Operator. A decision to sign an implementation agreement would signal Bonneville's attempt to join the EIM as long as certain principles are met during implementation and all outstanding issues are resolved prior to the go live date in 2022. Nita Zimmerman will be sharing more information on our process and timeline for that decision later this morning, and I encourage those of you interested in this decision and the other key elements at play to stay actively engaged throughout the process as it's an important milestone for Bonneville and our customers.

With that I'd like to turn it over to Joel Cook, our Senior Vice President of Power Services.

SLIDE 10 – POWER SERVICES

JOEL COOK: Thank you, Elliot, and good morning, everyone. I'm happy to report that Power Services' year-to-date performance was positive. Our forecast for the remainder of the year has declined from my first report.

SLIDE 11 – POWER SERVICES EXPENSE

Taking a look at expenses on slide 11, Power spent $33 million more than the rate case forecast during the first half of the year. This is primarily due to an increase in power purchases which have been driven by the cold weather that we've seen, below average water, and power supply constraints in the Northwest, which I will go into more detail in a bit.

Our current end-of-year forecast is $82 million less than the rate case forecast, which is an increase in spending compared to what we expected in the first quarter. An increase from the first quarter, again, is due to low water conditions, and the need to purchase additional power to meet our load and obligations. While we expect total expenses to be below the rate case expectations, it is important to note that our expenses would actually be above rate case when you adjust for the impact of the Regional Cooperation Debt transactions.

As a reminder, BPA did not include these transactions in the rate case forecast, but they are included in our fiscal year-end forecast. These debt management actions are reducing our expenses by $150 million this fiscal year, so they are masking the impact of the increased power purchases that we've made on our expenses. I do want to point out that we have maintained discipline on our IPR costs and have maintained what we committed to so far this year. Without those savings our forecasted expenses are above the rate case forecast of $76 million.

SLIDE 12 – POWER SERVICES REVENUES

Now, turning to slide 12, taking a look at our revenues. Power's year-to-date second quarter revenues exceeded the year-to-date rate case forecast by $37 million. Revenues were driven by the higher than expected market prices despite our lower than expected inventory due to the drier than normal weather. We also had more 4h10c credits from the U.S. Treasury. These are the credits we receive from purchasing replacement power as a result of our fish operations. For the year, we are expecting revenues to fall short of our rate case forecast by $16 million, again, due to the expected below average water supply as well as lower loads from preference customers. This brings our end-of-year net revenues forecast to $67 million above the rate case target. However, if you don't include the debt management actions as I mentioned earlier, our net revenues forecast is $92 million lower than the rate case.

SLIDE 13 – SNOWPACK CONDITIONS

Turning to slide 13, as I mentioned earlier we are currently anticipating a below-average water year, although it's still too early to be certain as we've seen some more snow in late April since our official forecast. This slide shows the snowpack conditions as of early April. Conditions have changed significantly since the last QBR update. Where previously the snow had been in pretty good shape in Canada and above Grand Coulee, we now see that those values have significantly dropped to below average. However, we have seen a sizeable increase in the snowpack and water supply contributions from the Snake River Basin, where we have seen an increase in seasonal volume forecast of about 8 million acre-feet since the official forecast was released on April 3. Even with the snowpack increases, we still expect a below average water year since the majority of the water supply contribution is above Grand Coulee where the snowpack conditions are less robust.

SLIDE 14 – HENRY HUB PRICES

Moving on to natural gas, in the first quarter Henry Hub prices reached relatively high levels in response to elevated demand and low natural gas storage throughout the U.S. on a national level. Prices fell below the rate case forecast in the second quarter as winter progressed and gas production growth increased. Taking into account forward trading, gas prices are anticipated to come in below the rate case forecast for the remainder of this year.

SLIDE 15 – MID-C PRICES

We're now on slide 15, Mid-C. Except for the short reprieve during January, power prices have continued to be very strong during the second quarter. The big story in the Northwest continues to be the surging natural gas prices in the region due to constrained supply coming from British Columbia and the pipeline that suffered an explosion back in October. While the pipeline has been repaired it has not been operating at full capacity and won't likely for the rest of the fiscal year. The constraint is exacerbated during periods of strong power demand such as during colder than normal weather which occurred in both February and March. Compounding the situation we see little to no wind and weak hydro generation during the second quarter. These factors push Mid-C prices well above BPA's rate forecast during February and March.

Entering the third quarter, Mid-C prices are moving back closer to the rate case forecast as regional natural gas prices have dropped. However, the sub-par water supply forecast and expectations for continued constrained natural gas supply, Mid-C forward prices during the higher demand period of the summer are trading above the rate case forecast. Overcoming the overall revenue loss of a sub-par water year will depend greatly on the rest of the water year plays out, especially this summer.

SLIDE 16 – BPA BALANCING AUTHORITY LOAD AND RESOURCES

This next slide is a new slide. There are several simultaneous factors including the ones I've just covered that have led to high and volatile prices that impacted our bottom line last quarter. This chart on this slide shows a snapshot of what was happening in late February and early March. Working from the bottom up, the green line depicts the fact that there was little to no wind generation during the cold period. The brown line shows the reduced thermal generation in our balancing authority. The purple line reflects the excellent performance we had from the Columbia Generation Station. And the blue and red lines show hydro generation and load respectively. The increase in hydro generation on March 4, where you can see the uptick in the graph there, is a result of BPA calling on Treaty storage water from Canada, and that not only had a significant impact on lowering price, but relieved many of our constraints on power supply.

This situation was further exacerbated by the work on the California side of the Direct Current Intertie which limited imports into the Northwest. These conditions led to high power prices and limited supply across the Northwest, at one point pushing prices close to $900 a megawatt. We continue to operate the system to maximize the value of our customers and committed to providing reliable service. We will continue to monitor conditions throughout the year, including this summer when we expect prices to peak again.

SLIDE 17 – POWER CAPITAL EXPENDITURE

Moving on to the capital, slide 17. This chart shows the capital expenditures on assets at the federal dams as well as Fish and Wildlife and IT projects. Power's total capital expenditure through the second quarter are $40 million less than the rate case forecast. This reflects unspent funds by Fish and Wildlife which frequently materialize in the later half of the year. Looking forward, Power's total capital expenditures for the year are forecast to be $74 million less than the rate case. This reduction is largely within the Federal Hydro Program due to factors including available resources, refining project scopes, and reprioritizing of projects.

SLIDE 18 – POWER CAPITAL WORK PLAN COMPLETE

The next capital slide focuses only on the federal assets and shows the percent of units completed compared to the percent of our budget that we've spent. Federal Hydro completed 92% of the work planned in the first half of the year for a total of 12 projects, while spending only 75% of the planned budget. The remaining budget supports ongoing work on the multi-year project.

SLIDE 19 – FEDERAL HYDROPOWER RELIABILITY

Moving on to reliability. We measured the federal hydropower reliability using the forced outage factor. This reflects the percentage of hours the federal system is not available to unplanned outages. We work to schedule these outages for maintenance during periods of low demand, but a few unexpectedly go offline because of forced outages during high demand it may impact the amount of power BPA has to purchase or could otherwise have sold. We continue to work with the U.S. Army Corps of Engineers, the Bureau of Reclamation, and their plant staff to ensure units and other assets are maintained regularly, replaced when necessary, and to minimize forced outages.

The value for the second quarter is trending in the right direction, downward, as we have experienced lower forced outage rates due to these efforts. Several units have either already returned to service or are expected to return later in the third quarter. The year-to-date forced outage factor for the Federal Columbia River Power System is currently at 4.7% versus our 5.9% target.

SLIDE 20 – COLUMBIA GENERATING STATION RELIABILITY

The Columbia Generation Station exceeded its target for the second quarter with 100% availability. This means it did not experience any outages in the second quarter. I'd like to thank our partners at Energy Northwest for assisting us with this baseload need during our cold snap in late February and early March. In addition, I'd like to share some agreed upon additional flexibilities that we're going to be receiving from CGS. About a year ago we asked them to study the dispatch flexibility from the plant and they came back and have more than met the requested flexibility that we'll begin to implement in the near future.

I'd now like to turn it over to Richard.

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SLIDE 21 – TRANSMISSION SERVICES

RICHARD SHAHEEN: Thank you, Joel, and thank you, Elliot, and good morning to everyone. I'll start my report with an overview of Transmission Services Q2 financial forecast and provide an overview of transmission reliability and wrap up with a few transmission topic updates. Starting first with financials. I'm happy to report that our second quarter financial performance was positive and our forecast for the remainder of the year has improved.

SLIDE 22 – TRANSMISSION SERVICES EXPENSE

Starting with slide 22, which shows Transmission's first six months of expense actuals versus rate case plan. Transmission's second quarter end-of-year expense forecast – as can be seen in the summary table in the right-hand side of the chart, upper right-hand side – is $2 million less than our rate case full fiscal year expense projection. This is primarily driven by a reduction to our depreciation expense schedule and cost management actions targeting Operations, Maintenance, Asset Management, and Commercial Operations Programs.

SLIDE 23 – TRANSMISSION SERVICES REVENUES

Next, looking at Transmission total revenues on slide 23, again, you can see our actuals for revenues versus the BP-18 Rate Case plan for the first six months. Transmission's second quarter end-of-year revenue forecast, again, reflected in the table on the upper right-hand of the slide, is forecast to be approximately $2 million less than our full fiscal year rate case revenue projection. Lower revenues were driven mainly by lower short-term sales due to lower water coupled with a reduction in megawatts purchased as customers renew contracts. These reductions are partially offset by additional conditional firm sales that have exceeded our rate case expectations.

The increase in conditional firm sales resulted from changes to how we model and award this product. Combined, Transmission's lower expenses shown in the previous slide and lower revenues shown on this slide result in a current net revenues forecast of negative $7 million for the fiscal year, which is right in line with our rate case projection.

SLIDE 24 – TRANSMISSION CAPITAL EXPENDITURE

Now, moving on to the status of Transmission's capital program starting with slide 24. This chart shows actual capital expenditures to date compared to the rate case projection. Transmission's capital expenditures for the year are currently forecast to be

$67 million less than the rate case. Several factors are contributing to this. Some customer-funded projects have been withdrawn or delayed by the requesting customers. Additionally, overall project throughput continues to be challenged as a result of a greater number of smaller projects and fewer large projects than was anticipated in the rate case.

SLIDE 25 – TRANSMISSION CAPITAL PLAN COMPLETE

Moving on, slide 25 shows the percent of units completed compared to the percent of the budget spent. We’ve completed more work than expected in the second quarter, completing 136% of our plan while only spending 72% of the planned budget. While we do forecast a lower capital expenditure, we are working to complete our total forecast asset installation count by the year’s end. Our planning, engineering, supply chain, and construction teams are constantly finding more cost-effective solutions to complete work at lower costs.

SLIDE 26 – TRANSMISSION RELIABILTY – SAIFI

Now, turning to transmission reliability starting with slide 24 – excuse me, slide 26. We measure transmission system reliability using the System Average Interruption Frequency Index, or SAIFI, and System Average Interruption Duration Index, also known as SAIDI. We use SAIFI to measure the frequency of outages on both our high-voltage and low-voltage systems, which are greater than 200-kV or less than 200-kV, respectively. In the second quarter, BPA was within its SAIFI target on both the higher and lower-voltage lines. In fact, higher-voltage SAIFI is doing particularly well, showing its best performance in the last 10 years.

SLIDE 27 – TRANSMISSION RELIABILTY - SAIDI

Turning now to SAIDI on the next slide, this shows the annualized duration of outages per line. In the second quarter, our SAIDI was over the target level for both the low and high-voltages. The primary contributor to longer high-voltage outage duration was a disconnect switch failure on our Buckley-Grizzly line in central Oregon at the end of March. Buckley is a complex site and this repair required vendor support which added to the ultimate length of the outage. The primary contributors to the low-voltage outage duration were five outages on our 115-kV voltage lines associated with a major snow event in the Eugene, Oregon area at the end of February, which I’ll talk about more in just a moment. These adverse conditions will not continue to weigh on SAIDI during the rest of this year. As such, it’s possible that SAIDI will improve during the second half of the fiscal year. However, the risk of significant fires or storms could further impact results.

SLIDE 28 – ENGAGE WITH TRANSMISSION

Finally, I'd like to share a few transmission business updates. In the area of Maintenance and Asset Management, as I mentioned we experienced significant impacts in our service territory due to the late winter snow storm that hit the Eugene area in February. Five 115-kV lines and one 230-kV line were forced out of service by snow-covered trees off the right-of-way that fell into the lines. The outages impacted several BPA customers, and BPA crews responded immediately beginning on the evening of Sunday, February 24. And the response escalated Monday morning as additional outage information became available. Transmission Field Services activated our Incident Management Team to coordinate emergency response and restoration efforts with our BPA dispatch. A total of seven crews, nearly half of BPA's linemen, were deployed to the Eugene area from as far away as Ellensburg, Washington. Other support staff were deployed including substation operators, electricians, mechanics, and helicopter pilots.

Crews worked 16-hour days and were provided eight hours rest to ensure they were able to work safely for an extended period of time. In one instance, Douglas Electric requested mutual aid to repair critical infrastructure and restore power to its customers. All BPA points of delivery were returned to normal service by Thursday, February 28. The event lasted seven days and crews returned to their normal headquarters only after work was completed. I want to take a moment to recognize the crews and BPA teams who completed this challenging work with zero accidents or injuries. It was an incredible accomplishment.

Next, regarding the status of reliability coordinator services, we're making good progress on our transition to the California Independent System Operator as our Reliability Coordinator and are actively involved with CAISO standing up its RC services. CAISO reports that it recently received certification from the North American Electric Reliability Corporation for RC implementation in California. There will be a certification review for CAISO's larger footprint this summer. Currently, the largest risk area is network model integration and we're working collaboratively with CAISO to address these risks.

And finally, on March 1, we signed the TC-20 Record of Decision. Thank you to all of our customers for engaging in the settlement process to make that possible. TC-20 implementation is now underway and we've established a schedule for multiple customer meetings to ensure we meet the commitments outlined in the ROD. We've engaged with customers on the hourly firm data collection and evaluation, and we have already initiated the new business practice process. The Product Conversion Team is beginning the analysis for customers interested in converting products in the first conversion window. Other commitments, such as implementing the designation of seller's choice agreement at the Mid-C and the revision of network operating agreements will be addressed in upcoming network operating committee meetings throughout the spring and summer.

Well, that concludes my Transmission Services update. Thank you for your time. And once again, my personal thanks to the BPA Transmission Services Team that continues to work hard towards providing our region transmission excellence. I'll now turn it over to Michelle Manary, our Chief Financial Officer, who will share our financial outlook for the year.

SLIDE 29 – FINANCE

MICHELLE MANARY: Thank you, Richard. We've had a busy quarter here in Finance. In a moment I'll update you on our financial reserves review and share information about a new decommissioning study for the Columbia Generating Station. But first, I will take you through our agency-level financial results.

SLIDE 30 – BUSINESS LINE FINANCIAL HIGHLIGHTS

Slide 30 summarizes what you've heard from Joel and Richard. We are below rate case levels for agency net revenues forecast. The main thing to note is that the power expenses presented here do not include the debt management actions Joel mentioned early. This gives you a clear picture of impact below average water conditions are having on our net revenues this year.

SLIDE 31 – AGENCY FINANCIAL HEALTH

On slide 31 on the left you see a breakout of our expenses into two categories, Integrated Program Review costs, or IPR, and the other costs, shown as Non-IPR, that are driven mostly by market and hydro conditions. Even though we actively manage all of these expenses, we broke it out here so it's easier for you to track our progress and our commitment to keep program costs down.

The agency Q2 forecast for IPR expense is under rate case expectations by $66 million. This is largely due to our ongoing cost management efforts. As you can see, our consolidated agency revenue forecast is generally trending in line with rate case. Note that this revenue total won't match the sum of Power and Transmission revenues because we eliminate between business line transactions at this agency view.

SLIDE 32 – AGENCY NET REVENUES

Taking into account lower revenues and lower expenses, BPA currently anticipates ending the year $70 million above the rate case expectations. However, this is $84 million below rate case expectations when you remove the impact of the debt management actions Joel mentioned earlier. There is still a lot of uncertainty in how our hydro conditions will impact our expenses and revenues going into the summer, but we will continue to look for ways to mitigate the impact on our bottom line by managing our expenses and maximizing our revenues.

SLIDE 33 – FINANCIAL RESERVES

Okay, before I get to our actual reserves number, I'm going to take a minute to step back and provide some context around where we are in our reserves process and how that factors into our second quarter forecast. As you may recall, we did not present a reserves forecast the last two quarters. When we spoke to you at quarter one we committed to completing our reserves process improvement and timed to issue a reserves forecast at Q2. While we continue to work diligently on the reserves issues, we've competed enough of a review to put together a forecast of where we think we are today. As we shared at the March 11 Financial Reserves Workshop, our detailed review uncovered an error in how cash transactions had historically been allocated between business lines.

Going back to at least 2004 this misallocation has led to $277 million in deductions from Power's cash balance that should have come from Transmission. I want to stress that none of the findings so far call into question our combined agency finance reporting that gets audited every year. In the workshop we presented a staff leaning for how to correct the error, including how to treat interest. Our staff proposal is to transfer $330 million of financial reserves from Transmission to Power. That incorporates the principle amount and interest. It's important to remember that our review is ongoing. We have heard from many of you that you wanted to see our complete review before commenting on a decision, and we have adjusted our process accordingly. We're targeting to have a final decision this September.

Since March 11, as our review has continued in Finance, BPA's internal audit team and Baker Tilly, an accounting and consulting firm we've contracted with, have been working to validate our review. We plan to report out on progress periodically as our work continues. Those updates may come as Tech Forum updates, webinars, or workshops depending on what information we have to share, so stay tuned. We will host a workshop to present our staff findings and proposal before holding a comment period. If you'd like more information on our review, please visit the financial reserves review page in the Financial Public Processes section of BPA.gov.

Our second quarter end-of-year financial reserves forecast includes the $330 million transfer from Transmission to Power that was presented as the staff leaning on March 11. While this does not represent a final decision, we believe it provides the most useful forecast information for you at this time. We are also showing the split of reserves from reserves available for risk and reserves not available for risk, which we committed to taking a second look at back in November. More detailed information on our methodology for determining which bucket reserves fall in, as well as a crosswalk of how we got to this point, will be shared this Friday at the technical workshop.

SLIDE 34 – DAYS CASH ON HAND

With that as context, let's turn to the numbers on the days cash on hand slide on page 34. Days cash on hand is a key indicator of BPA's financial health. It is essentially the number of days that BPA can continue to pay for its operating expenses with the amount of reserves available for risk. As you can see, the agency and Transmission are exceeding their rate case targets for days cash on hand while Power is just two days below its lower threshold.

As you may remember, last year Power and Transmission had great financial results that led us to start fiscal year 2019 with more reserves for risk than we expected in the rate case. However, as fiscal year '19 has progressed, our reserves for risk forecast has come down, primarily due to decline in Power's net revenues. However, when you look at the two years together, we are still above rate case projections by $65 million, taking the total agency days cash on hand from 62 to 74 days.

SLIDE 35 – FINANCIAL RESERVES THRESHOLDS

Now, let's look at how these reserve forecasts translate into the probabilities of triggering a cost recovery adjustment clause, or CRAC, the financial reserves policy surcharge, or the reserves distribution clause for fiscal year 2020. For those of you not familiar with this chart, the pink portion is where we would trigger a cost recovery adjustment clause, which is a one-time rate increase to recover unexpected costs. The striped area would trigger a surcharge to help build up reserves, and the blue area would trigger a reserves distribution clause. The white area is where no rate action would take place.

Transmission is in the reserves distribution clause range, but with a very low probability of triggering. This is because we are below the reserves distribution threshold at the agency level. No modeling scenarios resulted in a power CRAC triggering, largely due to the staff proposed transfer of $330 million from Transmission to Power. This proposed transfer has also reduced the probability of some amount of a reserve surcharge, which is now estimated to be 61%. Please remember, the BP-20 final record of decision will set the actual threshold levels based on the days cash on hand metric outlined in the financial reserves policy, and any surcharge would be based off the actuals.

And now I will turn it over to Nita Zimmerman.

NITA ZIMMERMAN: All right.

MICHELLE MANARY: Sorry about that, and I am one page off. So, the Columbia Decommissioning Study, I don't think Nita wants to talk about that.

SLIDE 36 – COLUMBIA DECOMMISSIONING STUDY

My last topic today is on the new site-specific decommissioning study for the Columbia Generating Station. At the request of Energy Northwest, BPA completed a new study last February. This is the first site-specific decommissioning study for Columbia and the first update since 1989. The study provides new information on the cost associated with the eventual decommissioning and closing of Columbia. This includes the cost of monitoring the site and storing fuel until it is removed.

The new study estimates that decommissioning Columbia would cost $1.4 billion in 2018 dollars if immediate dismantling began in December of 2043. This is considerably higher than the cost estimate in the previous study. In accordance with the Nuclear Regulatory Commission requirements we have been contributing to a decommissioning trust fund for Columbia for quite some time. BPA believes the trust fund is adequately funded for BP-20 even with the updated numbers. So, we don't expect any BP-20 rate impact. And that's it for that. Thank you to Nita and I'll turn it over to her now.

SLIDE 37 – GRID MODERNIZATION

NITA ZIMMERMAN: Thank you, Michelle. I appreciate the opportunity to share another update on our grid modernization effort and on BPA's evaluation of the Energy Imbalance Market. Grid modernization is our sole key strategic initiative. We're making strategic investments to support a more reliable, flexible and efficient system, reduce future cost, and create new market opportunities. As we discussed last quarter, a roadmap is available that highlights the timeline for completing all of the grid modernization projects we have scheduled over the six-year initiative. We currently have 26 projects in flight. This roadmap will continue to be updated on a quarterly basis and was recently updated at the end of Q2. It is posted to the Grid Modernization page on BPA.gov under the Initiatives tab along with other updates.

SLIDE 38 – SPENDING YEAR-TO-DATE

Moving on to our spending year-to-date. Year-to-date we've spent $5 million in incremental spending and $2 million in existing spending on grid modernization efforts. Incremental spending is the use of additional funds put in place in the BP-18 Rate Case. Existing spending is the money the business lines were already planning to invest in grid modernization. Since the first quarter we have seen an uptick in spending as projects ramped up and more projects came online, which is what we were expecting. Although spending-to-date is still low, we still anticipate spending the full $15 million in incremental funds by the end of the year per our current forecasts.

As I indicated last quarter, low spending to date is due to the fact that the first half of the year was spent on thorough up-front scoping and planning to ensure a smooth execution on projects. We will continue to closely monitor spending on grid modernization throughout the rest of the fiscal year.

SLIDE 39 – ENERGY IMBALANCE MARKET TIMELINE

The next slide reflects our approach and timeline for assessing the merits of joining CAISO's Energy Imbalance Market. The timeline shows the expected schedule along with the work we need to complete to determine how BPA as a balancing authority would join and operate in the market. It also includes time for customers to determine what role they wish to assume. Our EIM team started a stakeholder process in July 2018 to determine how and under which conditions we could join the EIM. This summer BPA expects to issue a decision document on BPA's intent to enter into an EIM implementation agreement with the CAISO.

Customers and constituents will have 30 days to comment. BPA will consider these comments and develop a record of decision on whether to sign the EIM implementation agreement. A decision to sign will signal BPA's intent to join the EIM as long as certain principles are met during implementation and all outstanding issues are resolved prior to the go live in 2022. The decision whether to sign the implementation agreement is the first of several decisions that need to be made before we can begin market participation.

Steps we've taken to date include continued engagement with our customers and stakeholders in the region and bilateral engagement with CAISO. We've also been holding monthly stakeholder meetings to walk through the structured scenarios that show how the EIM would impact BPA's business as well as our customers. We're in the process of updating the initial cost-benefit analysis and we'll present that information in our next EIM stakeholder meeting on May 15. If BPA signs the implementation agreement this summer we would start spending money on the EIM projects that are identified on the grid modernization roadmap in orange. Several of these projects would need to be completed ahead of joining in 2022.

Stakeholder engagement would continue until market participation begins. Due to the voluntary nature of the EIM, even if we sign the implementation agreement we can decide not to join the market if a significant issue emerges that reduces our anticipated benefits. Similarly, if we join and don't see benefits we can leave the market. If BPA signs the EIM implementation agreement a final decision to join the market is scheduled for December 2021 after BPA issues a draft close out letter with a comment period in October of that year. We encourage customers and constituents to attend our EIM stakeholder meetings for more information.

Now, I'm going to turn it over to Scott Simms who's going to cover some of the other upcoming processes that you can be involved in.

SLIDE 40 – PUBLIC ENGAGEMENT

SCOTT SIMMS: Thanks a lot, Nita. I'm going to quickly share where you can join us in meetings and processes in FY 2019 and provide a heads-up on current comment periods and then we'll close today with a brief Q&A. But first, I just want to make a quick clarification from slide 11 during Joel Cook's presentation. On the debt management actions where we're reducing our expenses, it may have sounded like $150 million, it's actually $159 million this fiscal year. So, I just wanted to make sure to clarify that for our listening audience and for recording purposes.

SLIDE 41 – PUBLIC MEETINGS

Okay, with that let's get on to some of the upcoming public meetings. On Thursday, May 2, we're holding our third public meeting in Issaquah, Washington to discuss the time and extent of the end-of-lease line reintegration projects for the Sammamish-Maple Valley and Monroe-Novelty Hill transmission lines. As a reminder, these are BPA lines that had been leased by Puget Sound Energy and recently returned back to BPA.

On Friday, May 3, Finance will provide additional information to customers and constituents on some of the financial topics discussed today: the Columbia Generating Station decommissioning trust fund and the second quarter financial reserves forecast being two of those topics. The meeting will also provide an update on the Integrated Program Review, following through on our commitment to keep looking in every corner of BPA for cost savings after the 2018 closeout was issued back in October.

As Nita mentioned, there is an EIM stakeholder meeting on May 15 and the next TC-20 implementation update meeting will happen June 13.

SLIDE 42 – COMMENT PERIODS

One more. We have one comment period, I had to flip the page here. One more comment period open on the spill surcharge. We're asking folks to submit comments by Thursday. And with that we're going to transition on here. So, questions and answers.

SLIDE 43 – QUESTION AND ANSWER

That concludes our presentation portion today and we'll now transition over to our brief question & answer session. I'm pleased to see that even with sunny weather out there we've got a number of questions that are being submitted by folks.

So, one of the first questions, we're going to hand it over to Michelle on the financial front.

MICHELLE MANARY: Yes, thank you, Scott. So, the first question I have says, "Please confirm that the 2019 end-of-year forecast shown on slide 34 includes the approximate adjustment of $330 million reserves from Transmission to Power." So, yes, it does. So, let me take you to page 34. If you look at the reserves available for risk, the third line down, that actually shows the 288 that's in the fourth column over. That 288 includes the 330. As you remember what Joel was talking about earlier, that absent Power having a lot of Power purchases here, that would've been higher, but that is net from the loss of the net revenues. So that 288 does include the $330 million in transfer of reserves from Transmission to Power.

The second question is, “Please reiterate the amount of reserves. The slide presumes our transfer from Transmission’s to Power.” I think it’s the same thing. So, we did transfer $330 million from Transmission’s to Power.

ELLIOT MAINZER: The assumption.

MICHELLE MANARY: The assumption. So, this is the assumption, and this is a good point that Elliot has made that this is a forecast at this point in time. This is not a final decision. It’s a staff leaning and we will have another public workshop, if not some webinars, and a call later this summer and have a final comment period and conclusion in September. This is a forecast at this point in time.

SCOTT SIMMS: Great, thank you, Michelle. We also had a question from Randy Gregg on the designated obligations. This is from the composite true-up table on the Power side of the business and I think because it’s not part of the call today we well endeavor to get back to Mr. Gregg and also post that on our QBR site. So, more to come on that one. So let’s just take a quick pause here to see if we have other questions coming in.

MICHELLE MANARY: Yep, I have one more.

SCOTT SIMMS: Oh, one more, all right.

MICHELLE MANARY: Yes, and this is slide 36, the Columbia decommissioning study, and I apologize, what I failed to complete this slide is that we believe that the trust fund we have today adequately funds the decommissioning, the new study, when we look out to 2043. However, this is something we’ll be looking with the region as we go into BP-22 to look at those assumptions and see if we want a different risk profile or what we want to do. So, we will study that with our customers over the next couple of years, but today we believe it is adequate.

So, on slide 36, “What was the previous assumption of decommissioning costs?” You asked me the one question, I forgot that piece of paper and we will share that at the May 3 workshop, materials which I believe are going to be posted soon. And so that will be coming. But it was less, but we were never funding to that number in the first place, we were always funding more in the trust fund than what that number was.

Elliot Mainzer: Michelle, I’ll just add that I know on May 3 you’ll also have an opportunity to very clearly take the folks through any of the accounting adjustments we’ve have to make on our balance sheet, which is just as important everybody has a transparent visibility into those changes as well.

MICHELLE MANARY: Correct, correct.

SCOTT SIMMS: Okay, we'll just take one more pause here to see if we have any other questions. Okay, I'm not seeing any pop up.

SLIDE 44 – THANK YOU

SCOTT SIMMS: We'll just remind you about how to go ahead and submit questions if you want to at a later time. You can submit those questions in more detail by just emailing us at communications@bpa.gov. That's communications@bpa.gov. If you've already submitted a question today via Webex that we've not yet answered we do – you don't need to resubmit that, we will be getting back to you both in person and as well on our QBR site. And we'll be posting those follow-up answers to all of the questions on the QBR webpage. In fact, that's a great resource for prior submitted questions as well. If you have a topic you think warrants further discussion on these calls such as the financial topics we're talking about later this week, we'd like to hear from you. Please email us again at communications@bpa.gov with your topic ideas and we'll look at the best way to get that information back out to you, whether it's posted responses or short meetings.

So, to wrap things up we really appreciate you listening today. It was definitely a lot of meaty topics and we appreciate you engaging with us whether it's here in this quarterly call or in other regional forums, and we look forward to you joining us on July 30 for our next QBR. And with that, thanks, everyone and have a great day.