[SCANA] - SCANA Third Quarter 2015 Earnings Conference Call/Webcast
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Jimmy Addison; CFO
Steve Byrne; SCE&G; COO
Kevin Marsh; CEO

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Michael Lapides; Goldman Sachs
Dan Jenkins; State of Wisconsin Investment Board
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Presentation

Operator: Good afternoon, ladies and gentlemen. Thank you for standing by. I will be your conference facilitator today.

At this time, I would like to welcome everyone to the SCANA Corporation conference call. (Operator Instructions)

As a reminder, this conference call is being recorded on Thursday, October 29th, 2015. Anyone who does not consent to the taping may drop off the line.

At this time, I would like to turn the call over to Susan Wright, Director of Financial Planning and Investor Relations. Please go ahead, ma'am.

Susan Wright: Thank you. And welcome to our analyst call.

As you know, earlier today we announced financial results for the third quarter of 2015. And earlier in the week, we released an update on our settlement with the consortium regarding disputes on our new nuclear project.

Joining us on the call today are Jimmy Addison, SCANA's Chief Financial Officer; Steve Byrne, Chief Operating Officer of SCE&G; and Kevin Marsh, our CEO.

During the call, Jimmy will provide an overview of our financial results, Steve will provide an update of our new nuclear project, and Kevin will cover the key points of our settlement. After our comments, we will respond to your questions. The slides and the earning release referenced to in this call are available at scana.com.

Additionally, we post information related to our new nuclear project and other investor information directly to our website at scana.com. On SCANA's homepage, there is a yellow box containing links to the nuclear development and other investor information sections of the website. It is possible that some of the information that we will be posting from time to time may be deemed material information that has not otherwise become public.

You can sign up for e-mail alerts under the investors section of scana.com to notify you when there is a new posting in the nuclear development and/or other investor information sections of the website.

Finally, before I turn the call over to Jimmy, I would like to remind you that certain statements that may be made during today's call are considered forward-looking statements and are subject to a number of risks and uncertainties as shown on slide 2. The Company does not recognize an obligation to update any forward-looking statements.

Additionally, we may disclose certain non-GAAP measures during this presentation. And the required Reg G information can be found in the investor section of our website under webcasts and presentations.

I'll now turn the call over to Jimmy.

Jimmy Addison: Thanks, Susan. And thank you all for joining us today.

I'll begin our call by thanking those of you who reached out to us during the historic rainfall and flooding that hit South Carolina earlier this month. It was and continues to be a trying time for our state, and we appreciate your thoughts and prayers as things continue to progress.

While our system was restored very quickly, property damage of the citizens of South Carolina will take a long time to restore. And tragically, several lives were lost and families altered forever.

Now on slide 3, we'll begin our earnings discussion. GAAP earnings in the third quarter of 2015 were $1.04 per share compared to $1.01 per share in the same quarter of 2014. The improved results in the third quarter are mainly attributable to higher electric margins due primarily to weather, a Base Load Review Act rate increase and customer growth, as well as lower depreciation expense, as I will discuss shortly.

These were partially offset by lower gas margins, primarily due to lost gas margins of $0.06 per share resulting from the sale of CGT; an increase in O&M expense, and expected increases in CapEx-related items including interest and share dilution. Note that abnormal weather contributed $0.11 per share and $0.07 per share of additional electric margin in the third quarters of 2015 and 2014 respectively.

SCE&G periodically conducts depreciation studies related to electric plant to better determine the proper annual depreciation accrual rates. A new depreciation study performed earlier this year resulted in the adoption of depreciation rates which produced an annual decrease to depreciation expense of approximately $29 million.

The PSC authorized SCE&G to implement new depreciation rates effective January 1, 2015. And at the Company's request, the retroactive $14.5 million credit from the application of the new rates from January through June of this year has been used to offset the portion of the deferred fuel balance related to its retail electric operations.

For the third quarter of 2015 and all subsequent periods, the incremental reduction to depreciation expense will flow through income. Please turn to slide 4.

Earnings per share for the nine months ended September 30th, 2015 were $4.53 versus $3.06 in 2014. The improved results are mainly attributable to the net of tax gains on the sales of CGT and SCI, higher electric margins due primarily to a base load review act rate increase and customer growth, as well as lower depreciation expense as described earlier.

These were partially offset by lower electric margins due to weather from the first quarter, lower gas margins, primarily due to lost gas margins of $0.15 per share resulting from the sale of CGT; an increase in O&M expense, and expected increases in CapEx-related items, including interest, property taxes and share dilution. Although electric margins reflected a negative $0.01 per share due to weather year over year, abnormal weather increased electric margins by $0.22 per share year to date 2015, compared to $0.23 per share in 2014.

Slide 5 shows earnings on a GAAP-adjusted weather-normalized basis. Earnings in the third quarter of 2015 were $0.93 per share, compared to $0.94 per share in the same quarter of 2014. Year-to-date September, earnings were $2.90 per share in 2015, compared to $2.83 per share in the prior year.

As a reminder, GAAP-adjusted weather-normalized EPS excludes the impact of abnormal weather on electric margins and the net of tax gain from the sale of CGT and SCI from the first quarter of 2015.

Based upon our results to date and our expectations for the balance of the year, we are reaffirming our 2015 GAAP-adjusted weather normalized earnings guidance of $3.60 to $3.80 per share.

Now on slide 6, I'd like to briefly review results for our principal lines of business. On a GAAP basis, South Carolina Electric & Gas Company's third quarter 2015 earnings were up $0.06 compared to the same period of 2014. Increases in earnings were due primarily to weather, the continued recovery of financing costs through the BLRA, and customer growth.

The application of the previously mentioned new depreciation rates also positively contributed to earnings for the quarter. These items were offset by increases in O&M expenses and expenses related to our capital program including interest expense and share dilution. Year-to-date earnings were higher by $0.13 due primarily to the same drivers as the quarter, with the exception of weather.

PSNC Energy reported a seasonal loss of $0.04 per share in the third quarter of 2015, compared to a loss of $0.02 per share in the same quarter of the prior year, primarily due to increased O&M, depreciation, and property taxes; partially offset by customer growth. Year to date, 2015 earnings are $0.21 per share, compared to $0.23 per share in the prior year.

SCANA Energy, our retail natural gas marketing business in Georgia, showed a decrease in third quarter earnings of $0.01 per share in 2015 over the same quarter of last year, primarily due to increased O&M. For the nine-month period ended September 30, earnings were up $0.01 per share.

On a GAAP basis, SCANA's corporate and other businesses reported a loss of $0.06 per share in the third quarter of 2015, consistent with the prior year. Lower interest expense at the holding company and increased margins in our marketing business were primarily offset by foregone earnings contributions from the subsidiaries that were sold during the first quarter of this year.

For the nine-month period, these businesses reported earnings per share of $1.37 in 2015, compared to $0.02 in 2014. Excluding the net of tax gains on the sales of CGT and SCI of $1.41 per share, GAAP-adjusted weather normalized EPS was down $0.06 from the prior year, again due to foregone earnings from the sale of the businesses earlier this year.

I would now like to touch on economic trends in our service territory on slide 7. So far in 2015, companies have announced plans to invest over $1 billion with the expectation of creating over 3,000 jobs in our Carolinas territories. We're excited by the continuous growth in our service territories, as the Carolinas continue to be seen as a favorable business environment.

At the bottom of the slide, you can see the national unemployment rate, along with the rates for the three states where SCANA has a presence; and the SCE&G electric territory.

South Carolina's unemployment rate is now at 5.7%, and the rate in SCE&G's electric territory is estimated at 5.3%. Of particular interest and attesting to our state's strong economic growth, approximately 80,000 more South Carolinians are working today than a year ago.

Slide 8 presents customer growth and electric sales statistics. On the top half of the slide is the customer growth rate for each of our regulated businesses. SCE&G's electric business added customers at a year-over-year rate of 1.6%. Our regulated gas businesses in North and South Carolina added customers at an accelerated rate of 2.8% and 3.1% respectively. We continue to see very strong customer growth in our businesses and in the region.

The bottom table outlines our actual and weather-normalized kilowatt hour sales for the 12 months ended September 30, 2015. Overall, weather-normalized total retail sales were up 1.7% on a 12-month-ended basis. We continue to be encouraged by the strong industrial expansion that has in turn led to strong sales growth not only in the industrial sector but also in the residential and commercial markets.

Now, please turn to slide 9, which recaps our regulatory rate basing returns. The pie chart on the left presents the components of our regulated rate base of approximately $9.5 billion. As denoted in the two shades of blue, approximately 86% of this rate base is related to the electric business.

In the block on the right, you will see SCE&G's base electric business in which we're allowed a 10.25% return on equity. The earned return for the 12 months ended September 30 in the base electric business is approximately 9.7%, meeting our stated goal of earning a return of 9% or higher to prevent the need for non-BLRA-related base rate increases during the peak nuclear construction years. We continue to be pleased with the execution of our strategy.

Our regulated gas businesses in the Carolinas continued to perform well. We're allowed a return on equity of 10.25% and 10.6% in South and North Carolina respectively.

Slide 10 presents our CapEx forecast. This forecast has been updated to reflect our most current CapEx projections for 2016 and 2017 and is now inclusive of our 2018 estimates. This forecast also reflects the Company's current estimate of new nuclear spending through 2018, including an estimate of the impact of the settlement with the consortium, which Kevin will address later. At the bottom of the slide, we've recapped the estimated new nuclear clip from July 1 through June 30 to correspond to the periods on which the BLRA rate increases are historically calculated.

Now, please turn to slide 11 to review our updated estimated financing plan through 2018. As a reminder, on May 19th of this year, SCE&G issued $500 million of 50-year bonds at 5.1%. Also in January, we issued approximately $14 million in equity through our 401(k) and DRIP plans before turning off the plans to new shares.

While acquiring shares on the open market to set aside the needs of these plans, we can further utilize the cash proceeds from the sales of CGT and SCI. We do not anticipate the need for further equity issuances until 2017 and will turn back on the 401(k) and DRIP plans to satisfy those needs.

On the debt side, and based upon cash flows and planned construction payments to date, we have deferred $325 million of Q4 planned debt issuances and accelerated some issuances from the out years to better align with our expected funding needs. This plan also anticipates debt to be issued at PSNC to fund its anticipated CapEx spending.

While these are our best estimates of incremental debt and equity issuances, it is unlikely that these issuances will occur exactly as presented, as they are subject to changes in our funding needs for planned project expenses. And we continue to ingest the financing to match the related CapEx on a 50-50 debt and equity basis.

Now, I'd like to discuss our 2016 earnings guidance and related assumptions as shown on slide 12. Our 2016 GAAP-adjusted weather-normalized preliminary earnings guidance is $3.90 per share to $4.10 per share, and our internal target is $4 per share.

Due to the cyclical nature of our business, we expect to earn approximately 30% of this amount in the first quarter, approximately 25% in earth of the third and fourth quarters, and the remaining 20% in the second quarter. In computing this guidance range, we have included the impact of a base rate increase from our new nuclear filing under the BLRA, the accretive impact of the sales of CGT and SCI, and our view of the economy.

This guidance also incorporates the CapEx and financing plans we presented earlier. We forecast electric customer growth to be at approximately 1.5%, offsetting our assumption that customer average use of electricity will be slightly lower in 2016. We anticipate overall weather-normalized retail electric sales growth for 2016 to decline by approximately 0.2%.

We expect operating and maintenance expenses to be approximately 2% higher in 2016 than where we project to finish for the end of 2015. We also expect continued growth in the CapEx-related cost of property taxes, depreciation and interest.

For the remainder of 2015, exclusive of the taxes on the gains on the sales of the subsidiaries, and looking out into 2016, we project an effective tax rate of approximately 32%. We continue to be cautiously optimistic about our long-term view and are reaffirming GAAP-adjusted weather-normalized average annual growth guidance, as we plan to deliver 3% to 6% earnings growth over the three to five years using a base of 2014's GAAP-adjusted weather-normalized EPS of $3.58 per share.

Hopefully, this will provide you with some clarity of our view of 2016 as you update your models.

I'll now turn the call over to Steve to provide an update on our nuclear project.

Steve Byrne: Thanks, Jimmy.

I'd like to begin by addressing the impact that the recent rainfall and flooding in South Carolina had on the new nuclear construction project. As you've probably already seen on our website, we estimate that this weather event resulted in a loss of about four days of work effort.

I wanted to clarify that the construction schedule has a contingency for weather delays and other events. So the missed days should not impact the planned in-service dates for the new units. We have had very little weather impact to date, which is why this event should not have an impact on the project.

Please turn to slide 13. I'd now like to address the Public Service Commission of South Carolina's unanimous approval of the petition that SCE&G filed in March of this year seeking approval to update the construction milestone schedule as well as the capital cost schedule for the two new nuclear units.

The approval of the petition, along with the settlement agreement entered into with the South Carolina Office of Regulatory Staff and the South Carolina Energy Users Committee, adjusted the commission-approved substantial completion dates to June of 2019 for unit 2 and June of 2020 for unit 3.

This agreement also allowed for the inclusion of incremental capital costs that totaled $698 million and revised the allowed return on equity to 10.5% from 11% for calculating prospective revised rates sought under the BLRA on or after January 1 of 2016.

Moving on to some of the activities at the new nuclear construction site -- slide 14 presents an aerial photo of the site from June. This photo gives you a view of the layout of the site, and I've labeled both units 2 and 3, as well as many of the areas that make up what we call the construction tabletop.

On slide 15, you can see a picture of the unit 2 nuclear island. In this picture, you can see module CA20 on the left side of the slide, along with the containment vessel first ring, which has been placed on and welded to the lower bowl. If you look through the personnel and equipment hatch openings in the containment vessel ring, you can see superstructure module CA01, which, as you'll recall, was placed back in July. We continue to make progress with the fabrication and placement of containment vessel structural modules.

Slide 16 presents a schematic view of the five large structural modules that are located inside the containment vessel. This exploded view of CA01 through CA05 gives you a better feel for how they fit spatially inside said containment vessel. As you may know, we have now placed CA01, CA04 and CA05 for unit 2.

Slide 17 shows a picture of CA02, which will be the next structural module placed in the unit 2 containment vessel. Module CA02 is a wall section that forms part of the in-containment for fueling water storage tank.

As you see here, all five sub-modules have been assembled. And CA02 is now structurally complete and has been moved outside of the module assembly building or MAB. This module is scheduled to be placed sometime in the first half of 2016.

Slide 18 shows a picture of CA03, which is the west wall of the in-containment refueling water storage tank. Four of CA03's 17 sub-modules are onsite, and three have been fabricated in the MAB.

Slide 19 shows a picture of the unit 3 nuclear island. Module CA04 was placed inside of the containment vessel lower bowl back in June. And the auxiliary building walls, as you can see, continue to take form.

Slide 20 shows an aerial view of the low-profile cooling towers from June. Three of the four cooling towers are now structurally complete, with the fourth, 2 Bravo, shown on this slide -- sorry, shown on slide 21 -- being about 50% complete.

Please now turn the slide 22. Here, you can see the placement of the concrete foundation for the unit 2 turbine building first bay. This six-foot-thick basemat took 27 hours to pour and consisted of 2,100 cubic yards of concrete. This first bay is a transition from the Aux building to the turbine building.

Slide 23 shows the completed unit 2 transformer bays. These transformer bays are constructed with reinforcing bar and concrete and serve as a firewall partially enclosing transformers. These nine transformer bays for unit 2 were completed during August.

Components continue to arrive onsite. On slide 24, you can see some pictures of the unit 3 pressurizer arriving in the Port of Charleston. It was then transferred via railcar to the site. Pressurizer will be housed inside the containment vessel and will be used to control the pressure in the reactor coolant system.

Please now turn to slide 25. As we mentioned during our second quarter call, we filed our annual request for revised rates under the BLRA in May. In response to that request, in September, the PSC approved an increase of $64.5 million. The new rates are effective for bills rendered on or after October 30th.

Our BLRA filings for 2015 are shown at the bottom of the slide. And as you can see, in August, we filed our quarterly status report on our new nuclear project with the commission and the Office of Regulatory Staff for the second quarter of 2015. We intend to file a quarterly status report for the third quarter in November.

I will now turn the call over to Kevin.

Kevin Marsh: Thanks, Steve. I'm glad to be with you today to provide some details in connection with our amendment to the EPC agreement for the new AP1000 units at the V.C. Summer site we announced earlier this week. A number of the key points are summarized on slide 26.

As you know, these plants were being constructed under an EPC agreement with the consortium of Westinghouse and Chicago Bridge & Iron subsidiary, Stone & Webster. Westinghouse has announced that it intends to acquire Stone & Webster from CB&I. Following that acquisition, Stone & Webster will continue to be a party to the EPC agreement, but as a subsidiary of Westinghouse instead of CB&I.

The amendment to the EPC agreement allows CB&I to exit its guaranty obligation for the project. The obligations under the EPC agreement are joint. And several obligations of Westinghouse and Stone & Webster in the October 2015 amendment provide for Toshiba Corporation, the parent company of Westinghouse, to reaffirm its guaranty of the Westinghouse payment obligation.

In exchange for the release of the CB&I guaranty, the amendment of the EPC contract and an option to fix project costs, SCE&G, Santee Cooper and Westinghouse have agreed to a full resolution and settlement of substantially all known claims and disputes outstanding under the EPC agreement.

Under this amendment, SCE&G has agreed to pay Westinghouse incremental capital costs of approximately $245 million over the $5.247 billion approved in the Public Service Commission's recent order number 2015-661. This, along with estimated installation and AFUDC, would bring the total gross construction cost for the project to approximately $7.113 billion. The amendment also revises the guarantied substantial completion dates of units 2 and 3 to August 31st of 2019 and 2020 respectively.

SCE&G's share of liquidated damages would increase from $86 million to $509 million. The new liquidated damages are tied to the new guaranteed substantial completion dates and the eligibility of the units to earn federal production tax credits. Westinghouse also has the opportunity to earn from SCE&G

completion bonuses of approximately $303 million or $151.5 million for each unit, depending on the timing of the plants being placed into service.

In addition, this amendment provides SCE&G for itself and its agent for Santee Cooper an exclusive and irrevocable option until November 1, 2016 to further amend the EPC agreement to fix the total amount remaining to be paid for the entire scope of work on the project after June 30th, 2015 at approximately $3.345 billion, which is SCE&G's 55% portion of $6.082 billion.

This fixed price option would result in SCE&G paying Westinghouse incremental project costs of approximately $774 million over the previous escalated amount approved by the PSC of $6.826 billion. Combined with estimated escalation and AFUDC, this would bring the total gross construction cost of the project to approximately $7.601 billion.

If the fixed price option is exercised, SCE&G's share of the delay-related liquidated damages amounts previously referred to would then be capped at approximately $372 million, or $186 million per unit. The completion bonus to be paid by SCE&G with this option is approximately $165 million or $82.5 million for each unit, depending on the timing of the plants being placed in service.

Our team worked very hard to include the unilateral fixed price option into this settlement. We will be evaluating the potential benefits of this option over the next several months. If elected, this option would fix all costs to Westinghouse at an approximate 11% increase over the current PFC-approved budget. We, along with our partner, Santee Cooper, believe this option has significant value.

Once our evaluation of this option is complete, we will discuss with the South Carolina Office of Regulatory Staff our conclusion regarding our decision of whether to exercise the option and make a filing with the Public Service Commission of South Carolina.

And important part of the amendment is the development of a new revised construction payment milestone schedule. Over the next five months, or until the new payment schedule is agreed upon, SCE&G will make monthly payments of approximately $100 million per month, of which our share is $55 million. Thereafter, payments will be made to Westinghouse based on construction milestones achieved.

After this milestone schedule is agreed upon, and if the fixed price option is elected and approved, our CapEx schedule Jimmy reviewed on slide 10 will be updated, and our financing schedule will be conformed as well. The amendment also modifies the EPC agreement to explicitly define what constitutes a change in law to reduce the likelihood of certain commercial disputes. A dispute resolution board will be established for resolution of disputes and for requirement or ability to bring suite before a substantial completion of the project has been eliminated.

Finally, I'm excited to have Fluor Corporation involved in the project. Fluor was established in South Carolina and has a strong nuclear pedigree with its nuclear division being headquartered in Greenville, South Carolina. We've had a long relationship with Fluor and believe they have an excellent record of delivering on commitments.

That concludes our prepared remarks. And we will now be glad to respond to any questions you might have.

Questions and Answers

Operator: (Operator Instructions) Andrew Weisel, Macquarie Capital.

Andrew Weisel: First question is on the option to switch to the fixed cost for the construction. What would be some of the reasons not to do it? You mentioned a lot of the benefits -- what might be some reasons why you wouldn't exercise it? And when do you think you might make that decision?

Kevin Marsh: Well, we'll make the decision over the next 6 to 12 months. We've had 12 months to make the final decision. We want to take some time to let Fluor get acclimated to the project, have them look at the project schedule, the timetable associated with the completion dates; and get their opinion combined with our evaluation of how they intend to approach the completion of the project, so we can evaluate the option we're under today, which is complete the project with the target pricing, along with the fixed and firm.

The bulk of the project left to be done is in that target category, which means we pay the cost that they incur. That's important to us. Because we want to get their feedback on the achievement of the milestones and what risk we think we may have there.

We think we've strengthened our risk position there, because we've increased the LDs on the project significantly. I think it's six times if we go under the existing option today. So once we get a chance to fully evaluate the schedule, the new completion dates, along with their oversight and our complete evaluation, I think we'll be in a better position to make that decision.

We certainly think the fixed price option is very appealing. We worked hard to negotiate that option into our settlement. We believe it does give us additional protections for rising costs. Certainly, interest rates and projected escalation rates between now and the time we make that decision would have an impact on which way we might go. But we just need some more time to evaluate that more fully.

Andrew Weisel: Okay. But it sounds like you're leaning toward taking that option? Or is it too soon to say that?

Kevin Marsh: No, I wouldn't make that decision today. I still think it's very appealing. And certainly it gives us a backstop if we aren’t want to be comfortable with the existing option. But I don't want to leave the impression that we've made that decision today. Because we want that time to evaluate where the project's going to what we think interest rates might do in the future; what impact that can have on escalation, and just the overall time schedule.

Andrew Weisel: Got it. Okay.

Next question is -- my understanding is that so far your payment schedule hasn't really been based on the completion of milestones. So you'll need to have a true-up of what's been paid so far. Are you expecting to be ahead or behind? In other words, are you expecting to get some cash back from cost overruns to date?

Kevin Marsh: We're certainly not ahead on the schedule. Because that was one of the things that drove -- it was behind many of the disputes on the project that we resolved with this amendment.

In the original agreement, there were two types of payments could be made. Some of those were based on time, just passing the timetable on the schedule; and others were based on actual work done. That got to be fairly contentious, because we felt like in some circumstances we were being billed for work that was not being completed consistently with the schedule we had agreed to in the original contract.

What this amendment does is it resolves those differences. So everything that's been paid to date is -- I think I'm confident saying that was for work that's actually been performed on the project. We're certainly not ahead of schedule.

So what we'll do is we're going to work with Westinghouse and Fluor very carefully to come up with a new construction payment milestone schedule. It'll take about five months to do that, we've estimated. So during that time, on a 100% basis, we'll be paying $100 million per month. And then at the end of six months, that'll be trued up, so we won't be ahead or behind at that point.

And then, from that point on, once we agree to the schedule, payments will be made as milestones are achieved. And that'll be very simply -- if the work is done, they'll be paid; if the work is not done in accordance with the schedule, regardless of how much time has passed, there won't be a payment required from us.

Steve Byrne: And that $100 million is 100% basis. So our 55% share will be $55 million.

Kevin Marsh: That's right. Thanks, Steve.

Andrew Weisel: Okay. And all of that is embedded in the financing slide that you showed through 2018?

Jimmy Addison: It is, Andrew.

So what we did in updating that schedule is simply took the formula that Kevin and Steve just alluded to and recast the first seven months according to that basis. And then the next five months of 2016, we just used an estimate of what we had there existing. So we have at least improved it for what we know for those first five to seven months. And we're just going to need to refresh everything once we get to that point where we're ready to take this before the commission, and we'll refresh our CapEx and financing schedule at that point.

Andrew Weisel: Okay, great.

Then, just lastly -- safe to assume that the financing plans -- then, equity in particular -- assumes no bonus depreciation? And what would that look like if you do have an extension?

Jimmy Addison: Yes, bonus depreciation is in the ballpark of $75 million a year. So that's the value of it to us. And you're right, it does not assume that.

Andrew Weisel: Great. Thank you very much.

Jimmy Addison: Thank you.

Kevin Marsh: Thanks, Andrew.

Operator: Julien Dumoulin-Smith, UBS.

Julien Dumoulin-Smith: With the depreciation benefits in earnings now helping you, I suppose -- and, you tell me -- drive towards close to your authorized ROE, how are you thinking about your earnings growth rate here? Obviously, it's better than the 3% to 6%. Just thinking more thematically here.

Jimmy Addison: Yes. Well, first of all, we have historically done and had an informal kind of commitment with the commission to refresh our depreciation rates every five years or so. And that's simple enough to do and get into the rate process when you have an inflation-related driven rate case every two, three, four years.

Since we have the strategy of staying out of any base rate increases other than the BLRA, we were getting on the outside of that timeframe. So we've refreshed it, went to the commission, asked them to approve it; they did. And we've implemented that now for 2015 and forward.

So it is kind of a one-time reset, if you will. Ultimately, it will all be kind of put back into the whole rate process at some point down the road after the BLRA is over and the new units are in place.

But in the meantime, you can say we might be on the upper edge or slightly outside the bend in the very short run. But that guidance is a three- to five-year intermediate band and not just a one-year band. So I don't know that that really puts us outside of that three- to five-year band. Because we reset that every year.

Julien Dumoulin-Smith: Right. But just to clarify real quickly -- in terms of earning your ROE next year, there's no reason why this step-up that you're seeing with the depreciation study -- that's a real sustainable benefit accruing to you guys?

Jimmy Addison: It is --

Julien Dumoulin-Smith: Until the next rate case, presumably, as you said?

Jimmy Addison: That's right. And everything gets reset then. But we're comfortable with our strategy of earning in that 9% to 10.25% range on base electric business for the next three years.

Julien Dumoulin-Smith: Got it. And --

Jimmy Addison: Based on what we know today, obviously.

Julien Dumoulin-Smith: Right.

And then, let me cut back to the sales growth expectations. Did I hear you right in saying a slight decline next year in the baseline forecast for the 2016 guidance? And can you expand on why that might be, given the year-to-date experience?

Jimmy Addison: Yes. Because the year-to-date experience is inconsistent with the last two years. If we were confident that we were going to get growth year over year from 2015 to 2016, we would have more upside. And honestly, I hope we experience that, because that's a great signal of the economy in South Carolina, if that's the case.

But at this point, our best modeling says that for the first time, there'll be almost a wash between the incremental margin from new customers offset by the slight margin decline from all customers due to energy efficiency, et cetera. And honestly, that's a good sign for us. Because as our whole industry has dealt with the last several years, the customer growth has been overwhelmed by the efficiency in the decline in average use.

So we're glad we're back to be able to project a breakeven. And I hope we have the challenge that you alluded to, because that's good news for the economy.

Julien Dumoulin-Smith: Right. And there's no specific customer class here that you're highlighting that would drive that, right?

Jimmy Addison: No. But the predominance of it is in the residential & commercial classes.

Julien Dumoulin-Smith: Right. Absolutely.

All right, great. Well, thank you. Congrats again.

Jimmy Addison: You're welcome.

Operator: Jim von Riesemann, Mizuho Securities.

Jim von Riesemann: Congratulations on the settlement.

Kevin Marsh: Thank you, Jim.

Jim von Riesemann: I just wanted to follow up on some of Julien's questions. How much is the depreciation effect supposed to impact fourth quarter earnings?

Jimmy Addison: Jim, it's about a $0.03 per-quarter run rate. So $0.12 a year.

Jim von Riesemann: Okay. And then -- so I guess a follow-up question to that is -- your trailing 12 is, what, $3.65, $3.66? And your internal midpoint before was $3.70 on a weather-normalized basis. Do you expect to hit that number?

Jimmy Addison: Do we expect to hit which number?

Jim von Riesemann: the $3.70 number, your internal target number?

Jimmy Addison: We do.

Jim von Riesemann: Okay.

Secondly, switching over to the settlement -- are the bonus payments included in the capital cost? Or are those incremental?

Kevin Marsh: They would be incremental, Jim. They're not included in the base cost we've disclosed in the amendment.

Jim von Riesemann: Are those shareholder-born, or customer-born?

Kevin Marsh: That has not been determined. We'll be before the commission and have a chance to explain both of these options, and then which one we choose to go with. Since we don't know exactly whether or not those will be paid out or what amounts they might be paid out in for one or both units -- because it's done on a per-unit basis -- we can't exactly determine if it's going to be paid.

We would like to have these projects completed on time and have that -- a nice problem to have. We'll address that with the commission. I'm likely to be asked by the commission how we perceive that. And my recommendation would be we wait till the end of the project to see where the final costs come in.

That's our most likely recommendation to the commission, since we can't determine exactly what that would be today. That might be influenced by which option we take, too.

Jim von Riesemann: Have you guys chatted with the rating agencies yet?

Jimmy Addison: Yes.

Jim von Riesemann: What was the response?

Jimmy Addison: Well, they've not published anything yet. I expect they will in the near term. But just to characterize the oral discussions -- I think it was generally neutral to positive with each of the agencies.

Jim von Riesemann: Okay. Can you just talk about -- lastly, could you talk about how the risks get re-bucketed from under this settlement? I mean, obviously, you've absolved some of your own risk that you bore. But what sort of risk would you say that you still retain and the risk that the construction consortium retains?

Kevin Marsh: Well, I would say our risk profile under either option is significantly enhanced. I mean, in fact, under the existing option that we've resolved all of these outstanding issues eliminates the risk of potential litigation on those issues and the risks that are just inherent in going through that process over time.

But I think the fact that we've significantly raised the liquidated damages gives us a lot more protection. Under the existing contractual arrangement, our liquidated damages are six times what they were in the original contract.

We still bear the risk of potential increased escalation, and just increased interest expense during that time on the targeted dollars. And the majority dollars to be spent between now and the completion of the project are in that target bucket. But I think when you all of those together, our risk profile is certainly reduced from where it was before we signed the amendment.

On the fixed price option that we have in front of us, I think that really enhances our risk profile, because we shift that escalation risk back to Westinghouse. And our only risk would be changes in law or change orders that might be associated with the project. And we've still got incentives payable under either option that would encourage them to complete the units on time.

So anything that helps that happen in accordance with the schedule and the guaranty completion dates would lower our risk profile.

Steve Byrne: Jim, this is Steve. I would give one amplification to that. Under either scenario, I think we've enhanced our risk profile. Because where we get into commercial disputes with the consortium today, they largely revolved around the definition of a change in law. And they would use the term commercially driven -- or, sorry, regulatory-driven change.

And the language around changes that we've worked on and incorporated into this agreement significantly restricts what would be allowed as a regulatory-driven change. So we've certainly improved it from that perspective.

We also have a contract, an EPC contract. Remember, that was signed in about 2008, early 2008. And that was based on the, at that time, current revision of the design certification document or DCD, which was Rev 16.

Jim von Riesemann: Right.

Steve Byrne: We were licensed to Rev 19. So they submitted a couple of revisions between signing it and the final approval. So that has caused us some commercial issues in the interim. And we resolved that with this agreement by updating the contract to BCV Rev 19, which is what we're licensed to.

Jimmy Addison: And Jim, just so we all get to pitch in on this -- one other from a financial perspective -- under the old agreement, any time we disputed an invoice, we paid 90% of it, as you're aware. Under the new arrangement, if we dispute it, we don't pay anything, and we get a fairly rapid resolution from a resolution board. So we think that's a much better situation, too, to get all the parties to the table. And of course, there's one less party to get to the table than there was in the past.

Jim von Riesemann: So let me ask like a worst-case basis type question. Has Fluor and Westinghouse looked at the quality of the work that has been done by CB&I?

Steve Byrne: Yes, I think that Fluor has not had an opportunity to look at the quality. Fluor will not take over until the deal is effective. There is a period of time for regulatory approvals of the deal -- standard stuff, perhaps complicated slightly by the fact that Toshiba is a foreign entity.

So there are regulatory approvals that need to take place. That's why we think that that will be about a 45-day window. And that's when Fluor really will have their first opportunity to assess things like quality.

But Westinghouse has had an opportunity to assess quality, as have our folks. And so we don't just rely on the quality from the vendor -- in this case, CB&I. We have our own quality group and our own quality inspectors.

And we send our folks not just at the site, but we'll send them to facilities that are manufacturing components, whether it be CB&I or somebody else. And we'll send them, whether it's domestically or internationally. Our QA/QC inspectors have got a lot of stamps in their passports. So we will be able to assure Fluor of the quality of construction so far.

Jim von Riesemann: So you're happy with the quality, so there's going to be no aha moment, is what you're saying?

Steve Byrne: Yes, we don't anticipate any aha moments.

Jim von Riesemann: Great. Thank you.

Kevin Marsh: Thank you. Jim.

Operator: Travis Miller, Morningstar.

Travis Miller: Wondering more on this regulatory stuff in terms of a settlement -- how much were regulators involved in this, either at the federal level, nuclear level, the state level? Was anybody involved, and what was that makeup in terms of regulatory involvement?

Kevin Marsh: They were not directly involved in the negotiations. Certainly, we briefed the Office of Regulatory Staff before made a final announcement of the settlement agreement. It was our commitment to the commission -- when we were in there earlier this year talking about the contract changes to getting the approvals at that time for the existing contract -- that we would come back to them and let them know of any changes in the status of the project.

So we expect to be before the commission here in the near future in the ex parte communication, which is the quickest way for us to get in front of them and educate them on more of the details of the contractual amendments involved, and how the options would work for the Company going forward.

And of course, once we make a financial decision, we'd be obligated to go back and make that filing through adjusting the timetables and the guaranty -- and the costs associated with it.

Travis Miller: Okay. You answered most of my second question there, terms of the regulatory process there. Is there a chance that regulators could deny the settlement, say it's not in customers' interest?

Kevin Marsh: Certainly they've got that option every time we go in. But our commission has been very supportive of what we've done on this project in the past. They view it as critical not just to provide energy to customers in South Carolina but as a key component for our response to the 111(d) Clean Power Plan. So it's critical for not just us, but also for our partner, Santee Cooper.

So we feel like we're living the guidelines of the challenges we were -- put before us to try to complete the project. Depending on which option we elect, we will go back and present our case to the commission as to why we decided to continue down the same path and why we believe it's the best interest to elect the fixed option.

And they generally listened to our testimony and evaluated that and made a fair decision. Certainly can't guarantee that. But I feel like we would do a good job explaining our position to the commission in a way that they can make a very fair evaluation of our election.

Travis Miller: Okay. And what kind of timeline would that be on?

Kevin Marsh: When we make the decision, once we make the filing, they have six months to render a decision. So if we were to make a decision, for example, to elect the fixed price option in early June next year, they would have to make that decision by early December. So it's a six-month window from start to finish.

Travis Miller: Got it. Thanks so much. I appreciate it.

Kevin Marsh: Yes, sir.

Operator: Paul Patterson, Glenrock Associates.

Paul Patterson: Does the fixed price option cover all materials and labor, or just some of them?

Kevin Marsh: It covers all remaining work to be done under the contract from now -- or actually, from June 15th until completion.

Paul Patterson: So it covers everything?

Kevin Marsh: Yes.

Paul Patterson: Okay.

And then, is there any change in your financing expectations or anything as a result of -- if you did move to the fixed price option?

Kevin Marsh: Paul, let go back and add one thing to my previous answer. It does cover the construction cost. We still have transmission work to be done. But that's included in the total expected project cost we provided. So those numbers are all included in there. Because the transmission is outside of the EPC contract, as well as owner's cost.

Jimmy Addison: Okay. And on to your next question about financing -- no change in our philosophy of 50-50 debt and equity. We just need to get through the process of reassessing with Fluor, making our option choice, going to the commission and getting that approval, hopefully, and then recasting the payments accordingly, and conform our financing schedule to them.

Paul Patterson: Okay.

And then, there's some fabrication discussion of moving the fabrication from Florida to other places. Is that affected by the amended agreement?

Steve Byrne: Paul, this is Steve. The discussion about a facility in Florida that was fabricating some of the sub-modules -- that was going to be the case whether we stayed under the existing contract or go under either of the two options that we're proposing.

So there's a facility in Florida. And they are moving that work from that facility in Florida back to the Lake Charles facility for the trailing unit. And for the leading unit, we're actually taking those components to our site, and we're finishing the sub-module fabrication there before we fabricate them into the larger modules.

Paul Patterson: And why is that? Why is being moved from -- what was the reason for the change?

Steve Byrne: I think it's two things. One, it's -- the debt facility had some commercial issues between themselves and CB&I. And secondly, they had a lot of work to do. Things were backing up. So they did have some quality issues while they came up to speed. And we just think we can do it more expeditiously at our site.

Paul Patterson: Okay, great. Thanks so much.

Kevin Marsh: Thanks, Paul.

Operator: Feliks Kerman, Visium Asset Management.

Feliks Kerman: Congratulations on the quarter.

I'll start -- this was already asked, so just wanted to clarify -- in our 2016 guidance number, what ROE are we assuming for the base electric business?

Jimmy Addison: Yes, we haven't been explicit about an ROE, but today we're at about 9.7%, and we're comfortable we'll be in that band of 9% to 10.25% for the next three years based on our assumptions to date.

Feliks Kerman: So is it okay to assume that the next time we file a rate case there would be after the three-year cycle?

Jimmy Addison: We've clearly said our strategy is to not file a base rate increase during these nuclear peak construction years. So yes. That is a safe assumption.

Feliks Kerman: Okay. Thank you.

Jimmy Addison: Sure.

Operator: Michael Lapides, Goldman Sachs.

Michael Lapides: Congrats on the arrangement with Westinghouse, Toshiba, et cetera. It sounds like a great deal, and look forward to chatting with you about it in more detail at EEI.

A couple of minor questions -- first of all, can you give us an update on how 2015 nuclear CapEx is progressing? I noticed the table didn't have 2015 numbers on it. And just wanted to see, relative to your last disclosure, whether there's been any change to the expected spend this year on the project.

Jimmy Addison: Yes, Michael. We are a little behind our expected spend there -- I'd say in the $100 million or so range. I don't know that a lot of that will be made up between -- obviously, with only a couple months left and the transition going on now. But that's kind of where we are through the year here today.

Michael Lapides: Got it, okay. So we should bring down our 2015 number a little bit and just assume that's embedded in the 2016-to-2018 timeline, or in the last year or so of the project?

Jimmy Addison: You can in your assumptions. I would tell you, though, from our basis, it's in our guidance both for 2015 and 2016.

Michael Lapides: Got it. Okay.

Real quick – on the D&A study and the impact -- I want to make sure I'm capturing the EPS impact of this correctly. So next year, what is the incremental EPS impact in 2016 that you're not going to recognize in 2015?

Jimmy Addison: About $0.06 will impact 2015, and an incremental $0.06 in 2016, for an aggregate $0.12. And that will be the run rate for 2016 forward.

Michael Lapides: Got it. And can you -- I want to make sure I tie that back. Because in the slide deck, it mentions $0.10 in this quarter, in third quarter. Is that just -- it's not the full $0.10 because of the rate credit that was done, or the reduction that was done on the deferred fuel balance?

Jimmy Addison: That's exactly right. So we did record three quarters' worth in 2015 in the third quarter because it applied back to January 1st. But the first two quarters went to offset the fuel, and so you only got net income impact of one quarter in 2015 through the Q3 recording.

Michael Lapides: Got it.

Last thing -- and looking at the CapEx schedule, the utility CapEx in North Carolina at the gas utility there -- seems like it's a good bit higher when we get out to 2017 and 2018. Can you talk about that, talk about the timing and plans for potential rate case filings, and how you would -- or are there other mechanisms that can give you rate relief after spending significant capital level there?

Jimmy Addison: Yes, well obviously, the low price of natural gas has driven a lot of opportunity for industry, for electric generation from gas plants, et cetera. And that has certainly been the case in North Carolina. So we've had an awful lot of opportunities that have popped up.

We have executed some contracts in the last quarter or two that have driven this need to enhance some of our existing plans to grow the transmission system. So that's what's really driving these numbers. And clearly, it's starting to drive down the earned return. And so it will drive the need for a rate proceeding it sometime in the near future.

We've not made any final decisions on that. But I expect we will have some announcement around that in 2016.

Michael Lapides: Got it. So maybe a case in 2016 implemented in 2017; or a case in 2017 implemented in 2018 -- kind of somewhere in that time horizon?

Jimmy Addison: Yes, again, haven't made any final decisions. But today, I would say it's more likely your first scenario than the second.

Michael Lapides: Got it, okay. Thanks, guys. Much appreciated.

Jimmy Addison: Sure.

Operator: Dan Jenkins, State of Wisconsin Investment Board.

Dan Jenkins: Just kind of following on Michael's questions that are on the CapEx changes. I was looking at the prior one, and looks like 2016 is up by about $260 million -- or no, about $120 million; and 2017s up by about $120 million, versus what you had in last quarter's slides. Was that due to the additional delays? Or is that due to the work not getting done in 2015, it's being pushed into 2016? Or how should I think about that?

Jimmy Addison: Dan, are you talking about the total CapEx? Because the numbers I have are that we're up about $60 million for 2016 and down about $60 million for 2017 overall.

Dan Jenkins: I'm looking at the bottom of the total estimated capital expenditures, at the bottom.

Jimmy Addison: Yes, we're only up about -- sorry, you go ahead.

Dan Jenkins: So the slide I'm looking at last quarter for 2016 estimated had 1,758, and for 2017 had 1,617?

Jimmy Addison: That's not what I have here in front of me. We'll have to clear that up.

Dan Jenkins: This is what I -- I just pulled it up from the website. So --

Jimmy Addison: Let me give you a little color on what we have changed. So we've made the best estimate we can on the nuclear, as I described earlier, for 2016, based upon the revised agreement.

The other thing we've done is -- there are reductions in the SCE&G base electric business, just based upon our commitment to scrub the CapEx for that business and try to avoid any base electric rate increases.

The other significant change is adding the CapEx to the North Carolina gas system, PSNC Energy. And so we added about $75 million in 2016 and $146 million in 2017 for PSNC.

So those are the three large changes. For 2016, $135 million down in electric, $53 million -- $75 million up in PSNC, and $115 million up in nuclear.

Dan Jenkins: Okay.

Then I had a question on slide 8, on the sales and customer growth.

Jimmy Addison: Yes.

Dan Jenkins: And again, looking at last quarter's release -- I realize these are -- I'm looking at the table at the bottom for the kilowatt hours. The last -- I realize this is 12 months ending numbers, but they were --

Jimmy Addison: Right.

Dan Jenkins: -- big changes in the weather-normalized. So the residential went from basically negative 30 basis points to positive 170, and commercial from positive 30 to positive 140. And then, conversely, the industrial went from 3.8% down to 2.3%. So are you seeing that kind of big changes from quarter to quarter? Or can you give me some more color on what's going on in the demand from the various customer segments?

Jimmy Addison: We are seeing that kind of change from quarter to quarter. And I would tell you that it probably has more to do with the slide before that on the economy than anything else in our opinion. Let me give you a little more depth on that.

So as I said in my earlier prepared comments, there are 80,000 more South Carolinians working today than there were a year ago. The unemployment rate has dropped from 6.6% to 5.7%. But that only tells part of the story. The workforce has expanded 3%. So if the workforce were the same level today that it were a year ago, the unemployment rate would be less than 3% in South Carolina.

So the industrial recruitment in the state has been a real homerun. Our governor has made that central to her platform, and she's been extremely successful. And we've seen it in the R&C markets as a result of that.

Now, contrast that to North Carolina, where the workforce has expanded 1.8%. Contrast it to Georgia, where it's actually slightly down, almost breakeven year over year. So South Carolina's really growing.

Dan Jenkins: I guess, kind of the concern, though, is the big slowdown in the industrial sector, and what that might mean going forward. Do you have any color to add as to why that dropped so much?

Jimmy Addison: I don't. I don't have any specific -- no large closings or anything like that that has driven it that I'm aware of. I'm not too concerned about them in the short run. I know the pipeline of projects that we're talking about that could be coming around the corner -- I just met this week with two -- with our head of industrial area about two new potential large projects in the area. So I really don't have any specific concern there.

I think some of those may be related to real-time pricing customers that chose to come off the system during the heat of the summer, rather than pay some of the prices they might've had to pay.

Dan Jenkins: Okay.

And then, my last question is just related to the nuclear construction schedule, and kind of critical path items. It sounds like maybe for unit 3, it's the CA02? Is that correct?

Steve Byrne: Say again, Dan?

Dan Jenkins: Critical path items, both for unit 2 and 3 -- so is the mix run for unit 2 that CA02 that you said is going to be placed in probably the first half of 2016? Or is there something else before that?

Steve Byrne: Yes, the next one of the structural modules to be placed will be that CA02 that you mentioned. The critical path right now on the units really is still running through the shield building. And we did place the first row of those shield building panels last quarter. And we anticipate doing some more of those in the near future.

But the critical path for the units, really for both units, still runs through that shield building – receipt of shield building panels, fit up the shield building panels, and then pouring the concrete in the panels. Once they're in place, then welded.

Dan Jenkins: What about -- so for unit 3, it's pretty much the same as unit 2? Or is there -- given that there's a year difference, and kind of the --

Steve Byrne: Dan, it's basically the same story for unit 3.

Dan Jenkins: Okay. Thank you, that's all I had.

Kevin Marsh: Thanks, Dan.

Operator: Mitchell Moss, Lord Abbett.

Mitchell Moss: Just wanted to get a couple clarifications on the nuclear cost. Looking at the slide that shows -- on that different options, just paging forward to that --

Kevin Marsh: Think that's slide 26.

Mitchell Moss: Slide 26, yes. Of the updated amounts comparing the old order to the amended EPC, is there a rough breakdown how much of that is related to the two-month delay in the substantial complete dates versus increase in construction costs or other stuff?

Kevin Marsh: Yes. The biggest part of that would be about $10 million a month in owner's costs. So approximately $20 million of that would be related to that category.

Mitchell Moss: Okay.

And then, if I think about the added cost going from the amended EPC to the fixed price option, it looks like it's around $500 million, I guess, of additional project cost. If I do the math from prior presentation, 2017 to 2019 CapEx is projected to be around $2 billion. So should I think that that incremental $500 million effectively would fix the 2017 to 2019 -- if you're not going to make your decision necessarily until late 2016, then effectively, you're really just fixing the 2017-to-2019 CapEx?

Steve Byrne: Well, Mitchell, we are fixing, if we elect the fixed price option. But it doesn't directly correlate to any kind of a specific burn rate. Remember, the real difference, as you look there at about a $500 million difference that you point out -- that really is the risk that the contractor will price in to fix it to us.

So what you're doing is you're paying a risk premium, and then they're having to make assumptions around things like inflation, or what the escalation rates are going to be. So that really was a negotiated number. But it really was reflective of the risk that now the contractor will have to take on.

Kevin Marsh: And it's also reflective of all payments made after June 15th of this year. If we elect the fixed price option, anything we pay or have paid since June up until the time we elect that option, we get credited for it 100%.

Jimmy Addison: And Mitchell, the CapEx schedule on page 10 -- we've made our best estimate of how this amendment will affect the cash flow in the short term. But as Kevin said in his prepared comments, once this milestone payment schedule is developed, we're going to have to conform the CapEx schedule, no matter which option we go with, to match that. So those numbers will change, I'm sure. I just don't know exactly how at this point.

Mitchell Moss: Sorry, they will change based on what?

The milestone payment schedule that Kevin covered earlier. So we're going to develop -- this milestone payment schedule is going to be tied to specific milestones being accomplished. And then we'll conform our CapEx and financing schedule to that, depending upon which option we elect.

Mitchell Moss: Okay. But once the fixed price option is selected, that milestone payment schedule won't matter so much.

Jimmy Addison: It will (multiple speakers) --

Kevin Marsh: The milestone schedule is really critical. Because what we're going to do here for the next four or five months is develop the schedule so there's clarity as to what needs to be completed for a payment to be made to Westinghouse. And so once that schedule is completed, there'll be dollars assigned to that if we continue under the existing contract. And then there'll be dollars assigned to that if we were going under the fixed price contract.

So the schedule will remain in place under either option. But the payments that go along with it will be based on whether we take the fixed price option or continue under the option we're working under today.

Jimmy Addison: So to contrast that, we're not going to make any payments in the future after this payment schedule agreed to based upon the calendar. They're going to be based upon actual results.

Mitchell Moss: Okay, thank you very much.

Kevin Marsh: Yes, sir.

Operator: (Operator Instructions) Julien Dumoulin-Smith, UBS.

Julien Dumoulin-Smith: So just wanted to reach back on the fixed price option and just kind of understand where the potential liabilities still lie on your side, if there is indeed a protracted schedule here. So could you perhaps give us a sense a little bit more -- I know you covered it a little bit with Paul, but to the extent you have a timeline shift, where are you responsible, what specific costs are you responsible for, in the fixed price option that you've laid out -- if you choose to go that way?

Kevin Marsh: Okay. The total fixed price options would be $7.601 billion, as we've laid out on slide 26 -- it's the third or fourth line down. That would be the total expected project cost. Of that, the capital cost portion, or the construction contract EPC contract would be $6.757 billion. So the additional amount would be escalation to date on the existing work that's been done, and then some additional dollars, the additional $20 million associated with the schedule, moving at two months for owners costs.

But the bulk of that is fixed in the fixed price contract. And that would be based on the guaranteed substantial completion dates of unit 2 August of 2019, and unit 3 August of 2020. And the liquidated damages are keyed off of each of those dates for specific units.

Julien Dumoulin-Smith: Got it. Could you give us a sense of how much you would be exposed to, and via what variables? If you were to have, for instance, the shift off in that August 2019 and 2020 date? Just to kind of give us a sense of the magnitude there? I mean, I appreciate that a lot of it would be presumably fixed. But --

Steve Byrne: Yes, Julien, this is Steve. The only thing that would not be fixed would be the things that we would be responsible for outside of the EPC contract. So that would be our owner's cost, and then the transmission. But we can finish the transmission even if the plants are not finished. So really, it comes down just to owner's cost.

Julien Dumoulin-Smith: And can you remind us what that is per month?

Steve Byrne: Yes, we're looking at a burn rate on owner's cost that's somewhere in the range of $10 million a month.

Julien Dumoulin-Smith: Got it. Excellent. Well, thank you again.

Kevin Marsh: Yes, sir.

Operator: Jim von Riesemann, Mizuho Securities.

Jim von Riesemann: Okay, I'm going to go back to depreciation a second, if you guys don't mind. So what were the assets that were changed in the deprecation to get such a big number on an EPS basis? I'm sorry, I've forgotten that.

Jimmy Addison: No, I don't know that you've forgotten it, I don't think it's been published anywhere. But we really -- we refreshed our entire comprehensive depreciation study across the whole electric system. So it includes the T&D and the generation system.

Jim von Riesemann: I mean, could you bucket which might've been generation versus T&D? And then, I'm trying to think of what your big generation assets are. Because already got ones that already have a long, useful life, right?

Jimmy Addison: We’re down to about five significant generating plants outside of new nuclear. And so I really can't give you the buckets here today, Jim. You can probably go to the PSC website and get more details on it publicly there.

Jim von Riesemann: Okay.

Steve Byrne: Big picture, Jim -- it's trying to match up the real expected lives to the depreciation schedule. And for example, at our nuclear facilities, we would anticipate that as opposed to just a 20-year life extension that we will be pursuing a second life extension. So that would take that plant out to 80 years total.

And then we're using actual history on some of the plants that we've been operating, and we're extending the depreciation scales out on those plants to again match up with what we really think is the useful life.

Jim von Riesemann: Okay, that's what I was after. Thanks, Steve.

Operator: David Fishman, Goldman Sachs.

David Fishman: I just have a quick follow-up on what Michael asked about. I was just wondering, does PSNC have historical or forward test years?

Jimmy Addison: Historical.

David Fishman: Historical? Right, great, thank you.

Jimmy Addison: Yes.

David Fishman: Congrats again.

Operator: Feliks Kerman, Visium Asset Management.

Feliks Kerman: Just a quick follow-up -- when we come down to the point of making a decision between the fixed option and the current, would it make sense to get commission approval prior to choosing the fixed option? Or how should we think about that?

Kevin Marsh: No, the way the process would work is we have an obligation to go back to the commission if there's a change in the price, the capital cost schedule that they've already approved. So either option would require us to go back to the commission at some point. So we need to make an election of which option we believe is superior, so we can go back to the commission, ask for approval of that option.

It wouldn't be likely that we would go back to the commission and say -- tell us which one you like, and we'll head down that road. They'll look for us to make a recommendation, a specific recommendation to them.

Feliks Kerman: And when will expect that to happen?

Kevin Marsh: We have 12 months from the effective date to make that option. So -- and, excuse me, it runs from November 1st of 2016. That's the specific date in the contract.

Feliks Kerman: Okay, thank you.

Operator: And ladies and gentlemen, that will conclude our question-and-answer session. I would like to hand the conference back over to Jimmy Addison for his closing remarks.

Jimmy Addison: Well, thank you very much. And certainly so far, this year has been very eventful. We're very pleased with our progress with the resolution to the negotiations and with our financial results through the first three quarters.

We continue to focus on the new nuclear construction and on operating all of our business in a safe and reliable manner. And we thank you all for joining us today and for your interest in SCANA.

Have a good day.

Operator: And the conference has now concluded. We thank you for attending today's presentation. You may now disconnect your lines.