

SO CA EDISON-EXECUTIVES

**Moderator: Megan Jordan
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Coordinator: Good morning. My name is (Marcella) and I will be your conference operator today. At this time I would like to welcome everyone to the San Onofre Nuclear Generating Station media teleconference.

All lines have been placed on mute to prevent background noise. After brief opening remarks there will be a question and answer session. If you wish to ask a question, press star 1 on your touchtone phone.

Today's call is being recorded. I would now like to turn the call over to Janet Clayton, Senior Vice President of Corporate Communications. Thank you Ms. Clayton. You may begin your conference.

Janet Clayton: Thank you (Marcella) and good morning everyone. With me today are Edison International Chairman and CEO, Ted Craver, and Southern California Edison President Ron Litzinger.

We conducted a teleconference with investors earlier this morning and those materials are available at our Web site at edison.com. We'll make some brief remarks and then open it up for questions for Ted and Ron.

When we get to the Q&A please limit yourself to one question and one follow up. If you have further questions, please return to the queue. With that I'll turn the call over to Ted.

Theodore Craver: Thanks Janet. Good morning to all of you. I assume you've seen our announcement that we've decided to no longer seek restart of Unit 2 and Unit 3 of our San Onofre Nuclear Generating Station.

Excuse me. The principal reasons that we've outlined for that really are the continuing uncertainty around the future of the plant and what the approval process would be, and particularly how long the approval process might continue to be.

The other part of the reason is that while - when we originally proposed to restart Unit 2 and submitted that restart plan to the Nuclear Regulatory Commission back last October, there was a clear cost advantage to continuing to operate the plant.

But over time that economic advantage diminishes and at least our estimate is that by the end of this year it would really no longer be the least cost alternative, because while the plant sits idle we have to pay for replacement power cost as well as continue to pay the operations and maintenance cost of keeping the plant in the ready to restart when the approval would come through.

And those kind of doubling up of costs really erode the least cost advantage over time. So for those reasons again to clear out the uncertainty and move forward in a decisive way, as well as reduce the drag that was continuing from

having - the economic drag from having the plant, we decided to no longer seek restart and close the plant.

So perhaps best use of the time here is to answer the questions that you have on your minds. I have with me Ron Litzinger and between us we should be able to field the questions you have. So operator I guess we'll open it up to questions from the group.

Coordinator: Certainly sir. Thank you. If you would like to ask a question, please press star 1 on your touchtone phone. One moment for the first question please. The first question is from Rebecca Smith of The Wall Street Journal. Ma'am your line is open.

Rebecca Smith: Good morning.

Theodore Craver: Hi Rebecca. How are you?

Rebecca Smith: Hi Ted. I'm well. How are you?

Theodore Craver: Doing well.

Rebecca Smith: Thank you for this call and could you kind of walk us through what the process will be now in terms of retirement and then eventually decommissioning, and also tell us how much you've got in the decommissioning fund? I think it's quite a bit of money but could you walk us through that?

Theodore Craver: Yes sure. In terms of the decommissioning fund that's kind of the straightforward facts. I think you know how that kind of works. We regularly contribute to the fund.

It's sitting now at about \$2.7 billion. That's on an after tax basis. And we're also constantly updating what the costs will be for decommissioning, and in fact we're about ready to submit another set of updates on the - what decommissioning costs will be in the future.

So at this point it looks like it's around 90% funded with a balance of about \$2.7 billion. The other part of your question is a little harder to answer in terms of what exactly is the process.

But the - kind of the critical one is the NRC considers the plant to still be an active operating plant until the nuclear fuel is taken out of the reactor and put into the spent fuel pools.

So that's going to take a little while to do that for Unit 2. That's already been done for Unit 3. So within I'll say a matter of weeks to a few months that should be completed.

At that point it then kind of moves over to a different part of the NRC regulatory oversight as a plant that's being readied for decommission. But there's a whole series of notifications that have to be made to the NRC along the way.

And kind of the final point is full decommissioning of the site is going to be a multi-decade process, so this is a very long process to be fully decommissioned. Rebecca does that get to...?

Rebecca Smith: In other words the plant is going to be there for a long, long time and there's going to be fuel in wet or dry storage for a long, long time, correct?

Theodore Craver: Yes correct. The way really the vast majority of the nuclear plants in the industry are currently configured is after the fuel is cooled down enough in the spent fuel pools, it then goes into some form of dry cask storage.

So it goes into stainless steel canisters and then is laid up. So we have fuel both in our spent fuel pools and we also have fuel in dry cask storage. Until there's a permanent solution to storing, you know, spent fuel pool - spent fuel rods, it's largely going to be managed by dry cask storage onsite at the nuclear plants.

So this - as you say it'll be - until there's a permanent solution for that this'll be onsite for a very long time.

Rebecca Smith: Thank you.

Theodore Craver: You're welcome.

Coordinator: Our next question will come from Matt Wald of the New York Times. Your line is open sir.

Matthew Wald: Thank you and thanks again for the call. In 20/20 hindsight where did you go wrong?

Theodore Craver: Well I think the - obviously the issue that the steam generators have not performed as the original specifications. So the design and manufacture of the steam generators clearly is not performing the way they were specified.

So that's I think kind of the core of it. All - like any of these kinds of circumstances I'm sure we can find lots of things that if we could roll the

clock back we would try to do a little differently. And - but I think that's kind of the nub of it.

Matthew Wald: Just to follow up, did your company limit the engineering questions it asked and the review it did of this proposal in order to avoid having to go for a license amendment for new steam generators?

Theodore Craver: No. The whole process that's been used for replacing steam generators in the industry is a pretty well traveled path. After the first few were done several years ago at other plants, the so-called 5059 process was established.

And essentially I like to think of it as a test. It basically says, "If you have essentially the same form, fit and function as the previous steam generators then you can go forward with the so-called 5059 process."

When we went through that analysis, which takes quite some time to do, we determined that much of it was really standard and could go through the - a - the 5059 process.

But we actually did need to obtain some license amendments to our technical specifications in our license. So it's - the 5059 process is basically a - as I say it's a - it's kind of a test.

If you go through that analysis and you determine that yes, what you're proposing is essentially the same form, fit and function as what you had in there before, then you can go forward with the replacement.

Anything that's outside of that has to go through a license amendment process. So as I said we actually had a little bit of both in our case.

Matthew Wald: And you don't think you'd have benefited by doing a more thorough, excuse me, more thorough review up front that might've uncovered that these steam generators were prone to the failure mode that's developed?

Theodore Craver: Yes I guess in thinking about this we have asked ourselves that question, and I think the general sense we have is this was such a unique phenomenon but I'm not convinced a more thorough, you know, approval process would have uncovered the technical engineering issue, this so-called fluid elastic instability.

That's, you know, that's obviously the question that I think we've asked ourselves and others who will ask, but the best sense we have of it is the technical nature of that would not have really been identified in a lengthier process, because really the technical issue is a first of a kind, unique circumstance.

Matthew Wald: Okay thank you.

Theodore Craver: You're welcome.

Coordinator: Next we have a question from Abby Sewell, Los Angeles Times. One moment please. Ms. Sewell your line is now open.

Abby Sewell: Thank you. Ted can you talk a little bit about what this means in terms of energy planning for Southern California, and also about how Edison is going to proceed with the cost issue?

Theodore Craver: Yes let me do a few comments on this, and I'm also going to ask my colleague Ron Litzinger to talk about some of the reliability planning, resource planning.

First I think this is very much part of that uncertainty that I was talking about that we are really anxious to resolve and focus on going forward. I did have some conversations with the Governor and the President of the California Public Utilities Commission in the last couple of days really around this point.

So I think you will see shortly some intensity and a sense of urgency around getting California Independent System Operator, the California Public Utilities Commission, California Energy Commission, perhaps AQMD, the two utilities that are involved here, San Diego Gas and Electric and ourselves, and probably others to really sit down and focus on the long range planning requirements.

You know, one of the toughest parts about having to make the decision here to no longer seek restart is that nuclear plays a fairly unique role, particularly here in California in our energy mix.

It's the only large base load non-fossil fuel generating resource, and particularly given the state's goals on greenhouse gases and global warming, nuclear which represents around a little less than 20% of the total fuel mix in the state - now that's - a big chunk of that's now out of the mix and it will have to be replaced.

It'll be difficult for it to be replaced just with renewable resources because the nuclear is dispatchable, which means, you know, we can determine when it needs to come on and it's a major resource and a very important part of the grid.

So all of those things are lost with the decision here to no longer seek restart for San Onofre. And we need to figure out how we're going to kind of

rebalance the mix of resources not only for generating electricity, but for maintaining the integrity of the grid, the voltage regulation on the grid.

I'm going to ask Ron to maybe pick up a little bit on that, because your question really goes to a very essential part of what we'll be focusing on over the next several years.

Ronald Litzinger: Yes thanks Ted. You really hit the nail on the head with regards to the long-term planning. We will be working with CISO, California ISO, the California Energy Commission, the Public Utility Commission going forward.

We've already even had conversations this morning on that topic. We've eliminated a key uncertainty going forward. We had already been for many years in discussions of replacing the generating capacity at the existing coastal units, which were slated for retirement giving - given water quality regulations.

And so with San Onofre being sort of thrown into that existing planning mix it increases the challenge. The first step is to determine what generation will replace those coastal facilities and San Onofre, and then depending on where those generation resources are located we may need to plan for transmission lines as well.

If the bulk of the generation is located inside the Los Angeles Basin, there will be little need for transmission. However if a significant portion of that generation ends up outside the Basin, then we will need to add additional transmission lines.

Both of those take - generating stations and transmission lines take a long time to permit, so it's best we get started right away planning for that future. In the short-term Ted had mentioned, you know, voltage concerns.

South Orange County has relied heavily on San Onofre being there close to the load. We do have sufficient generation located in the broader Southern California area.

It's are we able to deliver that energy into South Orange County through the existing transmission system, which can get strained. We've done a lot of transmission upgrades both last summer and this summer.

We feel we're in pretty good shape for this summer coming up. Barring we don't have an unusually hot summer, wildfires that take the transmission line out or unexpected generation outages, we should be pretty good on the voltage in Orange County this summer.

Coordinator: Any further questions Ms. Sewell?

Abby Sewell: Yes. And could you also talk about the cost issue, how you're proceeding with that with Mitsubishi or through insurance or other means of potential cost recovery?

Theodore Craver: Yes. Abby I'm going to be pretty limited on what I can say about where we are with Mitsubishi, but if I can maybe just drop back one step and talk more broadly about what we have here.

There are kind of essentially three buckets of costs. There are replacement power costs. There are what we call O&M, operation - excuse me, operations and maintenance costs to maintain the plant.

And then there's the investment that's been made in San Onofre. So those are kind of the three buckets of costs, and essentially the cost recovery process will focus on four sources for picking up those costs or recovering those costs.

The traditional way of course is all these costs are passed through to the customers, to the ratepayers in the form of our rates. Additionally Mitsubishi - because - as we made clear in previous statements we have we believe significant claims there.

We do have an insurance carrier for the nuclear industry called NEIL, N-E-I-L. We have claims that we've submitted to NEIL. And then of course the fourth is the shareholder.

So those are the three buckets of costs and the four potential sources of recovery.

Coordinator: The next question is from Pat Brennan of Orange County Register newspaper. Your line is open.

Pat Brennan: Hello. I was wondering if you could tell us how this will affect the workforce at San Onofre. How many more layoffs might there be and how many have there been so far?

Theodore Craver: Yes. I'm going to ask Ron Litzinger to cover those pieces.

Ronald Litzinger: Yes we currently have approximately 1500 employees at the facility. Over the next couple of months we will be reducing that to approximately 600 personnel.

And then we will make some applications to the Nuclear Regulatory Commission to modify our emergency response plans and our security plans to reflect a facility that is in a shutdown condition rather than an operating condition.

And then once those two plans, the emergency response plan and security plan, are approved, we would then reduce the staffing down to 400. We would still be able to properly secure the facility with that 400 and respond to any incident that could occur for our facility in that shutdown condition.

Pat Brennan: And can you say how many layoffs there have been so far? And I'm taking it the layoffs that you just talked about will be more than was initially projected a few months back.

Ronald Litzinger: That's correct Pat. In our 2012 rate case we had put forward that we were going to reduce the forces at San Onofre such that its staffing was more consistent with other two unit nuclear stations throughout the country.

That resulted in a reduction of 730 personnel. Again that was planned several years ago. It was implemented this year and then the numbers I just - that's how we got to the 1500. The numbers that I gave you going forward are a result of the shutdown.

Pat Brennan: Thank you.

Coordinator: Next we have a question from Michael Blood, the Associated Press.

Michael Blood: Good morning.

Theodore Craver: Morning.

Michael Blood: As you know the company made a number of changes between the original steam generators and the replacement steam generators. Those changes included adding 377 tubes to each of the replacement generators.

The replacement generators weighed nearly 24 tons more. There were - there was a larger surface area. There were changes to the tube supports. What I'm wondering is what was the goal of the company?

Did you want to run at higher power or what - why were all these changes made compared to the originals?

Theodore Craver: Yes. Well first maybe we can clear up one piece. You know, this term of like for like is actually something - I'm not really exactly sure whether that's even grown up.

It's not in the 5059 regulation. There's no such term like for like. The term is really that the new equipment has to be of a similar form, fit and function to the equipment that it's replacing.

So there is no like for like and in this case in the nuclear industry steam generators have had a - an issue really across all of the plants or the vast majority of the plants, what they call cracking and corrosion of the tubes.

It was determined many years ago that the principal cause of that was the alloy, the type of metal that was used in steam generator tubes, so-called INCONEL alloy 600.

So that was - it was determined that the way you could solve the cracking and corrosion problem in the nuclear steam generators was to use an improved metal, the INCONEL alloy 690.

However the - that tube metal also does not conduct heat as well as the previous metal. So all of the steam generator replacements that have been done in the industry over the last many years really are to improve a problem with the metal and the cracking and corrosion.

So you certainly wouldn't want to put the same, you know, the same stuff back into the steam generators because you're just going to have the same problem, and that's where the improvements in the metal were made.

Again because the metal doesn't conduct heat as well, really you end up having to put additional tubes in there so that you can get the same type of heat transfer in the steam generators.

So really our - there's no additional power consideration here. It was really to address a cracking and corrosion problem. In fact in our case the two steam generator - or the two units, Unit 2 and 3 - had we not replaced the steam generators one of those units would have shut down in 2012, and the other unit would've had to shut down in 2015.

So they were really at a critical point where you could no longer, you know, plug the tubes and maintain safety. So they had to be replaced and that's what we did with the improved metal so that we could avoid the cracking and corrosion problem.

Michael Blood: And just as a follow up does Edison have any plans for building any new plants here as replacements? Has that been discussed or is it a possibility?

Theodore Craver: We haven't really come to any final conclusions on that. Excuse me. I took your question to mean any kind of plant and so we really haven't come to any conclusion on that.

We largely here in California have generation supplied by third parties, and the utilities themselves typically do relatively little of building and owning and operating their own plants since the deregulation started in the late 90s.

So we'll have to go through that process. That will be part of this planning process that Ron was talking about. And I think our operating assumption is we focus the vast majority of our investments on maintaining the electric grid on the so-called wires part of the business, so the transmission and distribution.

That represents about 90% of the investment dollars that we put in to the system every year. And generation and all the other things, you know, kind of general plant and equipment represents around 10%.

So I think our focus will continue to be strategically on making sure that we have a solid distribution system that is robust and capable of supporting many different kinds of generation including distributed generation and renewables.

Michael Blood: Okay and just - so just to clarify again. I'm sorry. The question of new plants - you said no decision had been made and that would include any range of plants, whether gas-fired, nuclear, what have you. Did I follow that correctly?

Theodore Craver: Yes.

Michael Blood: Thank you.

Theodore Craver: You're welcome.

Coordinator: Morgan Lee from San Diego Union-Tribune, your line is open.

Morgan Lee: Hi. Thanks for taking our questions. The - first off I wonder if you could - I'm not sure if you mentioned the cost of the actual steam generator replacement project, which I think has been submitted for over \$700 million, how that'll be treated.

And secondly if I might, some recently released documents by Edison officials show that there were concerns about the steam flows and anti-vibration bars, some of the things that came to pass as far back as 2004 and 2005. Can you talk about why those problems couldn't be resolved?

Theodore Craver: Yes so let's go on the dollars and cents piece first. Actually the numbers that we showed to our investors this morning is that the steam generator replacement project - the approved amount was \$665 million.

This is for us for our part of the plant and incurred to date \$602 million. In terms of - I'm not sure I completely got the second part of your question, but it sounded like you wanted to know about steam flows in the steam generators.

Morgan Lee: Well it was just - it's sort of another 20/20 hindsight question that some of the problems in terms of the dry steam, this fluid elastic instability...

Theodore Craver: Yes.

Morgan Lee: ...were - there were signs that there were concerns there early on in the design phase it looks like, and also about this part of the bundle at the top of the tube bundle.

So I just wonder if you can talk at all about in hindsight why that couldn't be fixed if it was spotted so early. I'm asking because this sort of just came out.

Ronald Litzinger: Yes. If you review the letters and the design reviews we did, those issues were challenged and brought up with Mitsubishi. They subsequently responded back and assured us that those issues had been addressed.

Morgan Lee: Okay. And just one small follow up. Edison supposedly was part of the design team, involved deeply in meetings. Did its engineers try and help them solve that?

Ronald Litzinger: Our engineers - as a owner and a purchaser of equipment the normal practice in the industry is you review and make comments. But the manufacturer is ultimately responsible for and qualified for the design.

Theodore Craver: I might add one piece in here because I think this is really an important concept. We are the licensee, Southern California Edison, so the Nuclear Regulatory Commission looks to the licensee as the responsible party.

It's our responsibility under that when we use vendors, whatever the vendors might be doing for us. And as you can imagine we use a lot of different vendors and buy a lot of equipment that's throughout the plant that comes from third parties where we haven't designed it, manufactured it or whatever.

And so the Nuclear Regulatory Commission and the industry has a phrase they use. They refer to it as intrusive oversight. And I think the simplest way

to think about that is it's not a matter of Southern California Edison just writing down on a piece of paper, you know, "Here's the basic specifications that we want.

You go out, design the thing, manufacture the thing and, you know, ship it over to us when you're finished and we'll put it in." If we took that approach, what I would call a passive or hands off approach, we would be very much derelict in our responsibility as the licensee.

So it is expected and indeed in this case we did become very active with the supplier, in this case Mitsubishi Heavy Industries, through this process of intrusive oversight.

We actually look at some of the letters and other discussion that's arisen here in the last few weeks as indeed a demonstration that we performed our responsibility of intrusive oversight correctly.

So it isn't a matter of simply handing somebody your specification sheet and saying, "Make it for me and bring it to me." We have to be very actively involved, questioning, challenging, asking for proof and all of those things in fact were done here.

Morgan Lee: Thank you. The only other question was was San Diego Gas and Electric consulted on this decision?

Theodore Craver: Yes.

Morgan Lee: Thanks.

Theodore Craver: Yes.

Coordinator: Mark Chediak of Bloomberg News, your line is open.

Mark Chediak: Yes. Ted and Ron, can you guys hear me?

Theodore Craver: Yes we hear you fine.

Mark Chediak: Hi Ted, how you doing?

Theodore Craver: I'm doing well. Thanks.

Mark Chediak: A question here regarding sort of the possible head to shareholders here. You guys disclosed some figures in your release but what is ultimately - what could shareholders ultimately be on the hook for here regarding cost recovery?

And it sounds like that tells us that it's going to be decided largely by the CPUC. And sort of the second part of that question is when do you see some clarity from the CPUC on cost recovery?

Theodore Craver: Yes great questions. So let me try it this way. In terms of, you know, the final determination it is as you suggested in your question. That will be a matter of resolving the Order Instituting Investigation on San Onofre that the California Public Utilities Commission started back in November of last year.

So we don't have an exact - there's no way to have an exact idea of what potential liability to shareholders could be until we get all the way through that process.

I saw earlier this morning that President Peevey from the PUC has urged I think was the word he used parties to get together and try to work out some sort of a settlement of all of these items and bring it to the Commission.

But whether it goes through that kind of a process, a settlement process, or it goes through the standard litigated process in the OII proceeding, we will end up eventually with an answer to the question.

But as of today we don't - we really don't have a way to approach that other than by looking at the handful or so of precedents that exist with somewhat similar circumstances.

So for instance San Onofre Unit 1 was decommissioned early and in fact if I remember it right it was - there was a steam generator issue involved there. So that gives a precedent.

The Mojave plant gives a precedent when that was retired early. Geysers - another plant - geothermal plant, so on. There are a handful of these different precedents that have taken place over the years here in California.

And when you look at those precedents you get some idea of how these things have been resolved in the past. Using those precedents and a margin of conservatism we made an attempt to estimate that.

In fact we're obligated as you know to do that under GAAP accounting rules, generally accepted accounting principles. So we did that. We talked to our investors about all of that this morning and that's what gave rise to the \$450 million to \$650 million range for an impairment.

And it's also what gave rise to us reducing our earnings outlook for the year by 20 cents earnings per share. It was really based on those precedents and - but we won't know the exact answer until we get all the way through the process. Sorry for the lengthy answer.

Mark Chediak: That's all right. And just one quick follow up question. If it is litigated through - if it does end up just being litigated, does the company have a sense of when that could ultimately be resolved by or does that still remain to be determined?

Theodore Craver: Yes it - only a swag and the swag comes from when the Commission combined a number of issues into the single proceeding, they indicated at that time that the final phase - there are four phases to this OII proceeding - that the final phase should be completed by the end of next year.

So I - don't take that as a quote but that's the - that was the rough guideline they gave on timing. But that said well they haven't even really come forward with a specific schedule yet for anything other than the first phase of the four phases.

So the best info we have at this point is sometime next year if we went through the full litigated process.

Mark Chediak: Okay thank you very much.

Theodore Craver: You're welcome.

Coordinator: Eileen O'Grady of Reuters, you may ask your question.

Eileen O'Grady: Thank you. Mr. Craver you mentioned the double cost at San Onofre and the uncertainty about the timing of the restart were making this plant uneconomic or the - not having the nuclear advantage any longer by the end of the year.

But actually wouldn't your 70 - how would your 70% plan have fared against that? Surely operating at 70% for five months and not really knowing the future was also not really a good plan economically.

Theodore Craver: Yes actually the way we evaluated that was as part of the conservatism and baking in additional safety margin, we determined that we could stop the fluid elastic instability by running the unit at reduced power.

The point of the five months was to be extra cautious on how long that we would actually run the plant before taking it down, reinspecting all of the tubes again to ensure that we were not having the fluid elastic instability reoccur.

The intention of course would be once we went through that inspection that we would put the plant back in service and for some period of time continue it at 70% power.

I think we had in our minds that perhaps that power could be moved up - that power level could be moved up over time. But when I made the comments about the evaluating the alternatives, we assumed Unit 3 would not operate and that Unit 2 would operate at 70% power for the remaining license period, so that means out to 2022.

And the total cost associated with that without worrying about in the analysis how it might be divvied up between ratepayers, Mitsubishi and all the rest of the stuff, but just the total cost of that alternative was less than the total cost of

the other principal alternative, which is to shut both units down and buy the power out of the market.

So that - when I made the comment in the investor call this morning that was the way the analysis was done. So it did assume 70% power through each of the subsequent fuel cycles all the way out to 2022, and it did assume Unit 3 would be shut down.

That was still less expensive than the alternatives. The problem is the longer the plant sits idle waiting for a definitive yes or no answer, we're racking up in a sense double costs.

We have the replacement power cost, but we also have the cost to keep the plant ready so that we could restart it when we got approval to do so. And that double cost ends up eroding that cost advantage over time.

Plus every day you delay you have one less day that you can run the low cost alternative. And so it creates a crossover point and roughly speaking that crossover point was the end of the year.

So the evaluation became, "Okay we know we're chipping away at the economic advantage every day that it delays a restart. What is the - what is our view of the reality of getting through the approval process and all the kind of inevitable legal challenges, appeals, stay motions and what have you even after the NRC staff would approve the unit restarting?"

And our conclusion was we couldn't get through all of those different components of the process by the end of the year, and in fact could very well be late into next year or even after that.

And that risk just wasn't worth continuing to push this thing forward and continue to rack up those costs.

Eileen O'Grady: Thank you very much. What do you hope happens with the investigations that have been called for now with this decision by the politicians and the State?

Theodore Craver: Yes. Well I assume whatever those requests are will continue to work their way through. You know, the ones that we've been focused on are really all the process with the NRC.

Eileen O'Grady: Right. Do you have enough dry cask room in your dry cask storage for all the fuel that you would need to move there eventually?

Theodore Craver: Yes.

Eileen O'Grady: Okay thank you.

Theodore Craver: You're welcome.

Coordinator: Kevin Smith of Los Angeles News Group, you may ask your question.

Kevin Smith: Yes hi Ted. Quick question. I mean, you've talked sort of in general terms about, you know, how you have to ensure the integrity of the grid and, you know, make sure that it, you know, you can have enough power.

When you talk about San Onofre, of the power you provide to all your rate - or your customers, what percentage did that provide out of that mix?

Theodore Craver: About 17%.

Kevin Smith: Onofre, about 17%. Okay, and then realistically I know you said you haven't, you know, you don't have any specific plans for new plants of any kind.

But what would it take, you know, whether you have those plans formalized now or not, what would it take to fill in that gap in your mind? I mean, how would you best characterize what you would need?

Theodore Craver: Ron you want to take a shot at that one?

Ronald Litzinger: Yes it would be a combination of gas-fired combined cycle plants and a few gas-fired peaker plants within the Basin. A portion of that energy could be covered through the renewable projects that are coming online.

So it would be sort of a combination but you'd have to fill in for that 17% energy need. And then the more critical question I had mentioned earlier is depending on where those plants are located, we may have to add additional transmission lines.

Kevin Smith: Okay. Thank you.

Theodore Craver: Kevin one thing that might be worthwhile to have in mind here, Southern California Edison today buys about 2/3 of the power that it delivers to its customers and it self-produces the other 1/3.

So using the numbers I was talking about before with San Onofre being around 17% of the energy that we deliver to customers, that mix will now become even more skewed.

It'll be, you know, getting - close to 7/8 of the power that we deliver to customers will be purchased and about 1/8 or so will be self-generated.

Kevin Smith: Thank you.

Theodore Craver: You're welcome.

Coordinator: Dan Morain, Sacramento Bee, your line is open.

Dan Morain: Asked and answered. Thank you.

Theodore Craver: Okay.

Coordinator: Thank you.

Theodore Craver: That was the easiest question yet.

Coordinator: Next up is George Lobsenz, The Energy Daily.

George Lobsenz: Yes thanks. Wanted to ask how important was the CPUC investigation and particularly the adverse initial decision from the ALJ there on cost recovery, how important that was to your decision making on this closure?

Theodore Craver: Yes maybe just a little clarification. So the CPUC - if I'm thinking about the same thing that you are, the CPUC really hasn't come to any conclusions relative to San Onofre.

So we don't have any proposed decisions here at this point and we're very early in that process. That's the Phase 1 of the four phases and so I think really all of the - kind of the economics if you will, the financial aspects of costs and cost recovery, those are still basically in process.

If you're referring to some of the Nuclear Regulatory Commission decisions, really the, you know, the critical one for us is the one regarding restart of Unit 2.

That's the plan we put before them and they still are in the process of or have been in the process of asking technical questions, so-called requests for additional information and we've been responding to those.

So no decision really had come forth from the NRC staff. The final thing that has happened was the Atomic Safety and Licensing Board ruling that came out on May 13, and absolutely that was very definitive for us because that's the ruling that made clear we were going to have a much more uncertain process.

And as a result of that uncertainty there were going to many more opportunities for, you know, various stay motions, appeals and we could foresee a very long, involved process to get to a final yes or no decision on our restart plan.

George Lobsenz: Okay but on the CPUC process clearly they - what was happening there raised the prospect that you would not be able to recover a lot of these costs of the outage at San Onofre and obviously those costs were piling up with replacement costs as time went by.

So even though that it was in a very early stage, was that not a major consideration that you - a lot of these costs as they continued to build that you would not possibly be able to recover them?

Theodore Craver: Yes I - first off no decisions were made there and it's just - it is a ongoing proceeding. It'll have I'm sure a lot of length to it and it'll have, you know, so it's a typical litigated process before the PUC.

But I think I'm getting a little better understanding of the issue that you're trying to get to, and I think the answer is yes. Because the shareholder in a sense is underwriting the regulatory risk of what the final cost recovery will be, that meant that these costs that I was talking about that were adding up without clarity about when the unit could restart and without clarity about how those costs were ultimately going to be recovered, that meant that the shareholder is effectively underwriting that risk.

And as we said in the - in our first quarter earnings call to investors we - that's when we highlighted the end of the year as the critical time when the low cost alternative of restarting the plant was going to cross over with the alternative of shutting it down and buying the power out of the market.

And we also said we are - we the shareholder are picking up this regulatory risk. We're underwriting this regulatory risk. So I think that's the point you were trying to get to.

It doesn't mean that we would end up picking it up, but it does mean that we are going to end up underwriting that risk until there was clarity on what cost recovery would be.

George Lobsenz: Thanks and just one last question. Did this process at the NRC become politicized, I mean, and perhaps overly politicized here in your view in terms of pressures being brought to bear on the NRC? Do you think that was a major factor in this case?

Theodore Craver: Yes. I mean, it's a fair question but I'm going to be frank with you. I just don't see a lot of mileage in kind of going and wringing our hands over this part.

I mean, what we really need to be focused on is eliminating the uncertainty, controlling the things that we have some influence over. We've done that with our announcement today.

We want to focus on how do we move forward in a positive way here, a responsible way? I think that's already underway. We already have the key groups working on how are we going to ensure the reliability of the electric system for our customers?

And that's really - that's why we exist. That's what we do so that's where we want to be on this rather than kind of looking at what the other, you know, kind of political issues might be on this.

George Lobsenz: Thank you.

Theodore Craver: You're welcome.

Coordinator: Our next question will come from Dan McSwain, UC San Diego.

Dan McSwain: Thank you. I'm with the San Diego Union-Tribune so we're double dipping and I thank you for that.

Theodore Craver: That's all right. Thank you.

Dan McSwain: I'm trying to get a handle on all of the costs. And at the PUC proceeding you talked about the three buckets. Do you have a running tab including projected replacement power cost of that total figure?

This would include the steam generator replacement, the unrecovered costs at San Onofre itself because you have made improvements over the years and also the replacement power that's going to be decided at the PUC.

What's that total figure that either ratepayers or shareholders or some of both are at risk for today?

Theodore Craver: Yes. It's a good question, and like a lot of things in regulator ratemaking a reasonably complicated answer. Let me try to start with one piece. The steam generator cost was the number I gave a few minutes ago in one of the other questions.

So the approved amount that relates to Southern California Edison - the approved amount was the \$665 million for the four steam generators. The amount of money incurred to date under that was \$602 million, so that's one part.

Kind of the next piece up is what is the total investment that we have in operating plant? So this number is about \$1.2 billion, so about half of that is the steam generator cost and the other half is what we call balance of plant.

Then there are a bunch of other components which really get into the arcane world of regulatory accounting, but something called construction work in progress or CWIP.

There's also nuclear fuel and inventory, so when you throw all of those components in you end up with a - an asset number related to San Onofre of about \$2.1 billion. So I'll call that the investment in the plant.

Dan McSwain: And that includes the steam generator and the...

Theodore Craver: Steam generator, balance of plant...

Dan McSwain: Okay.

Theodore Craver: ...this construction work in progress stuff and nuclear fuel and inventory, whether onsite or off.

Dan McSwain: So that's the total asset figure. Thank you.

Theodore Craver: Yes. Yes. So that's \$2.1 billion.

Dan McSwain: Okay.

Theodore Craver: The other numbers that you talked about were things that relate to replacement power cost. That's a little easier to put a handle on. Since the initiation of the OII, the Order Instituting Investigation, on San Onofre, that number is now about \$264 million.

If you go all the way back to January 1, which is a date that is mentioned in the OII, that number's about \$529 million. And then you're going to be sorry you asked this question that - then all the other stuff, which includes O&M, operations and maintenance cost.

It includes the return on the investment, which is what we recover in rates. That is the component that is, you know, quote our profit and a number of other components.

All of that since November 1 when the OII was instituted is about \$270 million. If you go all the way back to January 1 of 2012 that number is a little over \$800 million.

So you could say between the monies that have been collected in rates that we've already collected that are subject to potential refund, those numbers are the sum of the \$800 million I mentioned and the \$529 million so let's call it roughly \$1.3 billion.

And the investment in the plant including the steam generators, all the rest of the stuff, the construction work in progress, the nuclear fuel, all of that is \$2.1 billion. Are you sorry you asked the question yet?

Dan McSwain: Oh no, it's a big number and it's - this is all going to be handled in this four phase process in your view?

Theodore Craver: Yes. In some form or fashion, yes.

Dan McSwain: Okay just one follow up if I may. Did Edison along with its subcontractors do a cost benefit analysis that goes like this: We think we know what the problem was.

We could build a couple of new steam or tube arrays. I guess there would be four of them. And we could install them but my understanding is that the steam generator or the steam tube array could be replaced without cutting a new hole in the domes.

Put simply was there a cost benefit analysis done on what it would take to fix this plant and go back and try to operate it for another 30 years? Setting aside the, I mean, clearly your decision was driven by regulatory, political and economic uncertainty and along with power prices out in the market.

But did somebody sit down and pencil out what it would take to fix this - both units or is - were both units judged to be unfixable?

Theodore Craver: Yes actually embedded in your question was kind of the principal answer. You mentioned, you know, go fix it and run it for another 30 years. We have a license.

Without the license of course we can't operate the plant. That license expires in 2022 so that's basically another nine years. So all of the considerations that you just mentioned have to be thought about in the context of the current license period.

And in fact when the steam generator - the replacement steam generators were evaluated, that is the assumption that was made is that they would be put in and operated to the end of the current license, the 2022 period.

And remember I said earlier if we had not put in new steam generators we would've had to shut the plant down in 2012 for one unit, 2015 for another because the existing steam generators would have been deteriorated beyond the safety point if we went beyond those dates.

So that's kind of the starting point. So back many years ago there was an evaluation done along the lines that you talked about. What if we replace those faulty steam generator or worn steam generators with new ones?

That's the same thing the industry's been doing, you know, all throughout the country. And the - that evaluation proved that it did make sense to purchase replacement steam generators, run the plant out to 2022.

Now we - sitting here with only nine years left. We would have to assume we could get a license extension beyond 2022. If we can't make that assumption or we don't see sufficient reason to make that assumption, then you have to be able to put in the new steam generators that you're talking about.

And we - and they'd have to pencil out with only nine years of running time and they don't. You couldn't go out and replace the steam generators and make it pay economically with only nine years left.

You would have to assume that you could get a license extension for those economics to work for you. Our view was you couldn't - you could not assume you could get a license extension, particularly under current circumstances.

Dan McSwain: Are you at liberty to tell us what that cost was; what it would cost to fix them?

Theodore Craver: I don't believe we've disclosed any of that. You know, we've done some of that evaluation of course but we have not disclosed that number yet.

Dan McSwain: Okay thank you. Thank you. Thank you very much.

Coordinator: The next question is from Ed Joyce of KPCC. Your line is now open.

Ed Joyce: Yes, thanks Ted and Ron for making yourselves available to us this morning. I had one question to clarify on the CPUC process regarding the outage that's 16 months.

Does the clock stop ticking now with your announcement that the plant shuts down on those costs specifically?

Theodore Craver: Basically the precedent is replacement power exposure would stop once we shut the facility down.

Ed Joyce: And that formally doesn't happen until...

Theodore Craver: Think you've got us on a - I don't think we know...

Ronald Litzinger: Technicality.

Theodore Craver: ...a specific point here or there. But, you know, the fundamental point is once you've quote shut the plant down, then you're really not going to be - you can't be responsible for both sets because you're going to end up having the asset taking out of rate base.

You aren't going to be earning on that asset. That's the write off that we talked about today that we're going to be taking. So, you know, you either have the plant operating and it's in rate base and you're earning on that rate base and producing electricity, or you're not earning on it.

It's out of rate base and you're buying power out of the market, so it's one or the other.

Ed Joyce: Thank you.

Theodore Craver: You're welcome.

Coordinator: And our last question for today will come from Bill Freebairn of Platts. Your line is open sir.

William Freebairn: Yes thank you very much. You have said that the regulatory process became complicated. I'm wondering if you're thinking that there's something wrong with the way the NRC regulatory process is set up that it has taken this long to reach a restart decision.

Theodore Craver: Yes I'm going to really respond the same way that I did on the political question that came up. You know, it's - we got to look at this as we have to evaluate the facts and circumstances as they present themselves to us, take our best view of what's the responsible thing to do, what's the reasonable thing to do and we feel we've done that.

We've made our decision. Now we're really just focused on as I said trying to ensure that we can maintain the reliability of the electric system and serve our customers.

That's what we do. You know, I'm sure there'll be plenty of discussions in the future as there always are about what kind of improvements can be made to the process and what have you.

So we'll let the Nuclear Regulatory Commission deal with that on a go forward basis. We've made our decision based on the facts we have in front of us.

William Freebairn: Okay and just to clarify something that you had said earlier about the license renewal, I thought the license renewal had become a very routine matter for nuclear plants.

You know, none's ever been turned down. And what made you think that you could not conclude that you would be likely to get a license renewal?

Theodore Craver: I guess to be frank I would argue that it's not a - by any means an automatic process. Number one, it's an expensive process. It is in the neighborhood - we estimated it would be in the neighborhood of around \$150 million all in to go through it and it's not a quick process.

It's anywhere between three and five years and some of them have been longer than that. So it's by no means an automatic process. It's a quite lengthy process.

And I think again in the context of, you know, the events of the last couple of years from Fukushima to the desire for enhanced seismic studies at the California plants and our own situation at San Onofre, we did not anticipate that getting a license renewal would be a quick or easy process. It'd be quite a lengthy and expensive process and...

William Freebairn: Okay thank you.

Theodore Craver: You're welcome. So going to turn it back over to Janet here for concluding comment.

Janet Clayton: Yes. We know that there's still several of you who weren't able to get in the queue and we're sorry we didn't get to all of you. But our media team will

follow up immediately after the call, and of course our media line is 626-302-2255. That concludes today's call and thank you for joining us.

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