BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 080503-EI

In the Matter of:

ESTABLISHMENT OF RULE ON RENEWABLE PORTFOLIO STANDARD.
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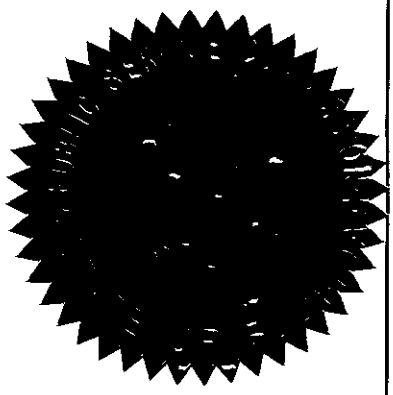

PROCEEDINGS: WORKSHOP

BEFORE: CHAIRMAN MATTHEW M. CARTER, II
COMMISSIONER LISA POLAK EDGAR
COMMISSIONER KATRINA J. McMURRIAN
COMMISSIONER NANCY ARGENZIANO
COMMISSIONER NATHAN A. SKOP

DATE: Wednesday, December 3, 2008

TIME: Commenced at 9:30 a.m.
Concluded at 5:05 p.m.

PLACE: Betty Easley Conference Center
Room 148
4075 Esplanade Way
Tallahassee, Florida

REPORTED BY: MARY ALLEN NEEL, RPR, FPR

PARTICIPATING:

DAVID BESSETTE, FlaSEIA.

SUZANNE BROWNLESS, for Florida Solar Coalition.

GEORGE CAVROS, Southern Alliance for Clean Energy.

SUSAN CLARK, Rady, Yon & Clark, for FPL, TECO, Progress Energy Florida, and Gulf Power.

JIM DEAN, Florida Pulp & Paper Association.

MICHAEL DOBSON, FREPA.

LEON JACOBS, Southern Alliance for Clean Energy and Natural Resources Defense Fund.

DELL JONES, Regenesis Power.

JERRY KARNAS, Environmental Defense Fund.

RYAN KATOFSKY, JAY PAIDIPATI, and MATT STANBERRY, Navigant Consulting.

JOSEPH McGLOTHLIN, Office of Public Counsel.

JOHN MOYLE, for Wheelabrator.

ROY RATNER, FARE

BOB REEDY, Florida Solar Energy Center.

GWEN ROSE, Vote Solar Initiative.

MARK SINCLAIR, Clean Energy Group.

THOMAS SUTTON, Sunshine State Solar Power.

MIKE TWOMEY, for AARP.

WAYNE WALLACE, FARE.

TOM BALLINGER, MARK FUTRELL, CINDY MILLER, RYDER RUDD, and BOB TRAPP, Florida Public Service Commission staff.

P R O C E E D I N G S

CHAIRMAN CARTER: Good morning. I would like to call this workshop to order.

Commissioner Argenziano?

COMMISSIONER ARGENZIANO: Good morning.

CHAIRMAN CARTER: Good morning to you. It worked. The system worked.

COMMISSIONER ARGENZIANO: Yes, it did.

CHAIRMAN CARTER: First of all, I want to thank everyone for being here this morning. And some of you from out of town, welcome to Tallahassee, and some of you from out of state, welcome to Florida. Please stay and spend a lot of money.

Staff, would you please read the notice.

MS. MILLER: I'm Cindy Miller with the General Counsel Office. Pursuant to notice issued November 14, 2008, this time and place were set for the workshop on a renewable portfolio standard rule in Docket 080503-EI.

CHAIRMAN CARTER: Good morning to one and all. The Public Service Commission has a longstanding policy of promoting the use of renewable energy in Florida. Today's workshop is a continuation of the Commission's exploration of our renewable portfolio standard, a policy which will further encourage the development of a market for renewables in Florida.

The Commission must submit a draft rule addressing renewable portfolio standards to the Legislature by February 1, 2009. In developing the draft rule, the Commission was asked by the Legislature to evaluate the current and forecasted cost and availability of renewables through 2020. To this end, Navigant Consulting was contracted to prepare a Florida renewables assessment.

The purpose of this workshop is to discuss the results of the study. We will also hear presentations from our staff regarding additional information that was requested by the Commission at the October 14th agenda conference. We'll have an opportunity for Commissioners and workshop attendees to ask questions of Navigant Consulting and our staff and to hear public comments.

The February 1 deadline to deliver a draft rule to the Legislature puts us on a tight time frame. I would like to stress that this will be our final scheduled Commission workshop. Accordingly, this will be our final opportunity to provide direction to staff. Staff is scheduled to file recommendations and a draft rule on December 29th of this year for our consideration at a January 9, 2009, special agenda conference.

Commissioners, this is our opportunity to explore technical and economic potential for renewables

in this state and to discuss how we believe the results of Navigant Consulting's study should affect our RPS policy. We want a full discussion of the issues so that we can give staff directions.

And with that, Ms. Miller, you're recognized.

MS. MILLER: We have Judy Harlow with a sign-up sheet, and let's see if she could stand up to show you -- there she is. So if you're planning to participate in public comment this afternoon, please sign up with her.

Let's see if there are any other housekeeping matters. Also, we have a sign-up sheet in the back by the door.

Thank you.

CHAIRMAN CARTER: Okay. Commissioners, anything further before we proceed? I want to give as much time as possible to the Navigant study, so at this time, I want you to welcome -- give me a shot, Jay. Let me try it. Okay? Jay Paidipati, Ryan Katofsky, and Matt Stanberry of Navigant Consulting. They'll provide a presentation of the results of Navigant Consulting's assessment of the technical and economic potentials for renewables in Florida.

Following Navigant Consulting's presentation, we'll have an opportunity for commissioners and staff,

as well as workshop participants, to ask questions regarding the study.

Good morning, gentlemen. You're recognized.

MR. PAIDIPATI: Good morning, Commissioners, Florida Public Service Commission staff, Governor's Energy Office staff, and other interested parties. Thank you for inviting us here to discuss the results of our draft study. And we will be presenting the executive summary of our study.

As Commissioner Carter mentioned, I'm Jay Paidipati with Navigant Consulting. I'm accompanied by Matt Stanberry and Ryan Katofsky. So with that, I will start discussing the executive summary.

This study was sponsored through a subcontract from Lawrence Berkeley National Labs, who received the funding from the U.S. Department of Energy's Office of Electricity Delivery and Energy Reliability.

So the next slide, this is the table of contents for the full study. And as I mentioned, I will just be -- or we will just be going over the executive summary today. It's a very long report, but we're just going to go through the beginning to give the high level overview and the results.

So the purpose of this study, the purpose of this study was to examine the technical potential for

renewable energy in Florida, first through 2020, the scope of our study, then to bound potential renewable energy adoption under various scenarios. At this point, I would like to point out that the scenarios are not predictive. What they are we will be discussing later on in our presentation.

And so the intent of this study was to not provide recommendations for what the renewable portfolio standards target should be, as we believe a statewide integrated resource planning process would be necessary first to be untaken to understand how renewable energy can fit in with Florida's current assets on the ground, planned generation assets already in the ten-year site plan, then also Florida's current transmission infrastructure, and then potential future transmission requirements, and then finally, the reliability requirements in Florida, and then future energy needs as the state may grow in the future.

So with that, I just wanted to go over our scope of work from Lawrence Berkeley National Labs. The first was to identify which resources, renewable energy resources are currently operating in Florida and then that could be developed through the year 2020.

The second task is to quantify what we call the -- I'll describe it in a few minutes, the economic

and performance characteristics, items such as quantity, cost, and performance of resources that are currently operating in Florida, and then again, that could be developed through the year 2020.

Then task 3 was to compare the economics on a levelized cost of energy basis of renewable energy to traditional generation right now.

And then finally, task 4, conduct a scenario analysis to look at various external economic impacts on how much renewable energy to be developed in the state.

So before we go into the body of the executive summary, there's a few key terms that we'll being using throughout the report that I wanted to go over here just to make sure we're all on the same page. The first is what I just mentioned of economic and performance characteristics. These are characteristics specific to each technology that drive their competitiveness over time, so these would be things such as O&M costs, installed costs, efficiency, capacity factors, et cetera.

The next is the technical potential. This is -- for a given technology, the technical potential represents all the what we call nameplate capacity or capacity. In this case, it's truly nameplate capacity that could be developed. And here the key phrase is

"independent of economics through the scope of this study, which is 2020." This accounts for things such as the availability of resources, where the technology is in its development stage, is it ready for deployment in Florida, is it not ready for deployment in Florida, then also competing uses for that space. Obviously, there's a finite amount of land in the state, so we wanted to make sure those things were accounted for.

The next is the scenario, and Matt will be discussing further what those are, but this is -- there's a lot of other variables out there such as cost of fuel, cost of natural gas, et cetera, the availability of credit, that we'll discuss in a little bit that will influence how renewable energy -- how competitive renewable energy will be in the future.

The fourth term is the levelized cost of electricity. We define that as the revenue per unit of energy required to recoup a plant's initial investment, cover the annual costs, and then provide debt and equity investors their expected rate of return.

But something I want to mention here is that we will be reporting LCOEs with the incentives and RECs factored in. Sometimes RECs are not shown in the levelized cost of electricity. We do that here, but we try to denote where that happens.

Second to last point is simple payback. This is of interest for our customer-sited PV systems. We've found in the past that the best way of looking at how customer-sited PV will be adopted is looking at the simple payback of the system, so the number of years required to pay back the initial investment where you're paying it back through electric bill savings.

And finally, the last one is -- what we're going to use is the phrase "technology adoption," or how much renewable energy is actually installed and operating in the state.

So how do we go about doing this? We took eight steps to do so. The first step is define what technologies will and will not be covered by the study. There's many renewable energy options that exist, but given Florida's resources in certain areas, not all of them are viable within the state, so we'll go through that.

Next, compile economic and performance characteristics for each technology. This was driven primarily by stakeholder data collected by the Public Service Commission staff, but then also where there was gaps, backed up by our work in this area as well, and then further interviews with stakeholders to discuss what the characteristics are. And then during this

step, we also surveyed what's currently installed for renewable energy in the State of Florida.

Next, Step 3 -- and we'll go into more detail in the next slides -- is assessing what is the technical potential in Florida through 2020. And we used various means, depending on the technology, to do that.

Step 4, develop the -- so Steps 1 through 3 are really getting at what could happen, and then Steps 4 through 8 are looking at, given other variables that influence renewable energy, how much could actually be adopted in the state. So Step 4 is developing some scenarios around different ways that those external variables might happen.

Step 5 is developing the actual inputs, the costs, et cetera, that might happen.

And then Step 6 is looking at how does renewable energy compete over time in those scenarios. For most technologies we used the levelized cost of electricity, and we assumed that the technology becomes competitive when the renewable energy technology LCOE becomes less than the LCOE of its competing traditional technology.

And then as I just mentioned, for customer-sited PV, we're using a simple payback period. And how that works is, we have a payback acceptance

curve, because there is a certain amount of elasticity for demand in PV, different amounts of customers are willing to adopt PV at different payback periods. Some early adopters are willing to accept longer payback periods than others, so we used what's called a payback acceptance curve that looks at, for a given payback, what percentage of the market will likely adopt PV.

And then also in Step 6, we looked at each scenario with and without RECs to look at the impact of what does a renewable portfolio standard -- what is the impact of having a renewable portfolio standard.

Step 7. In Step 6 we looked at the competitiveness. And just because the technology becomes competitive in a given year doesn't mean all the technical potential can be developed. There's a certain amount of inertia, if you will, of actually getting plants installed, and it takes time to do so. So we use what we refer to as technology adoption curves that are empirically based curves that look at historically how other technologies have been adopted over time, and we adapted those for use in renewable energy in Florida. So that gives you -- so Step 7 gives you the nameplate capacity of renewables installed over time for the given scenarios.

Then the last step is to, using the capacity

factors calculated in Step 2 or gathered in Step 2, calculate what is the generation each year for renewable energy in Florida.

And then we also spent a lot of time looking at what is the selling price for RECs going to be in the state. As the staff's draft legislation has it right now, 75 percent of the REC expenditures are to go towards wind and solar, the other 25 percent going towards the remaining technologies. So we took that into account and looked at, well, what REC prices will likely unfold over time. So that also -- then using that information, you can combine that with the generation to figure out what is the total REC expenditures in a given year.

And we bounded those by -- also in the staff's draft legislation, they cite a 2 percent cap on the IOU's retail revenue per year going towards RECs. We varied that number depending on the scenario, but you can look at where do actually REC expenditures fall relative to that cap.

Okay. So on to the first step. The first step was looking at what technologies are we going to cover in the study, and what's feasible given Florida's resource characteristics.

So the first is photovoltaics, short for --

the short is PV. Here we focused on three areas. The first is residential rooftops, the second is commercial rooftops, and then the third is ground-mounted applications.

Next is concentrating solar power. These are also referred to as solar thermal electric technologies. Given the resources in Florida -- a lot of concentrating solar power development is happening in areas of the country and the world with slightly different solar characteristics than the state of Florida. For concentrating solar power technologies, they require what is called direct normal insolation, so sunlight not filtered by clouds, not scattered off anything. And given the humidity and cloud cover characteristics in Florida, the resource characteristics are between 40 and 60 percent lower than areas that are seeing a lot of development activity in concentrating solar power. So because of that, we focused on a certain application of concentrating solar power where the -- instead of just the stand-alone concentrating solar power system, here the system collects heat and then provides it to the steam cycle portion of a combined cycle plant.

Next the solar water heating. Here, our study only covers systems greater than 2 megawatts thermal in size. Less than that, 2 megawatts thermal, is being

covered by a separate study that's going on somewhat in parallel in support of the Florida Energy Efficiency and Conservation Act, or FEECA, that is being done by a study by a team of KEMA and Itron, and I believe those results are going to be available later on in December sometime.

Okay. Great.

Next -- so those are the three technologies we focused on. Next, wind, first onshore. We focused on Class 2 and above resources. In the wind industry there's a rating system that essentially looks at the average wind speeds. It's Class through -- I believe 7 is the maximum, and so Class 2 is on the lower end. Class 1 resources, the technology really isn't developed and optimized to capture Class 1 resources. And then the economics, when the wind blows less, you recover your costs slower, so we only focused on Class 2 and above resources.

Then we also looked at offshore wind, and here, given the extra costs because of installing it offshore, the economics really don't make sense, and the technology is not really developed for Class 4 and above, so we focused there. So that's wind.

Next, three sort of distinct areas of biomass. The first is solid biomass, and Ryan will go into more

detail on that. But we examined a broad range of feedstocks present in Florida, and then also there's different technologies for converting that feedstock into electricity we looked at. And then also, I wanted to note here that this is also where we included municipal solid waste, in this category.

The next is landfill gas. There's already a fair amount, as Ryan will show in a few slides, of that developed in the state, but we looked at future potential.

Then anaerobic digester gas, this is where you take the gas resulting from anaerobic processes and convert it into electricity.

Next is waste heat -- I'm sorry. Those are the three biomass areas we focused on.

Next the waste heat. The staff's draft rule or legislation as is lists waste heat or electricity generated from waste heat resulting from the sulfuric acid conversion process, which is used in fertilizer manufacturing in the state. That electricity is eligible for the RPS, so we looked at that. And there's already a fair amount of it developed in the state, and we looked at further potential that could be developed.

Next, there's four areas. I would say this is the most undeveloped yet technology, that of ocean

energy. So there's four different technologies in ocean energy we looked at. The first is wave energy, which captures essentially the up-and-down motion of waves.

The next is ocean current, which captures essentially the -- in Florida, it would be the Gulf Stream, the motion of currents in the ocean.

Next is called thermal electric conversion. This takes advantage of the temperature differential. If you think of the surface of the ocean, and then farther down, there's a strong temperature differential, so you can utilize that to generate electricity.

And then tidal energy is deployed in areas where the tide rises a significant amount during the day such that you can draw electricity through a turbine. Okay? So those are the technologies looked at, and we're going to discuss the technical potential of those in a few moments.

The next slide is the economic and performance -- this is also -- so that was the first step, defining what we were going to look at. The second step was, okay, what are the characteristics of those technologies that will affect their economic competitiveness? So the next step or Step 2, we collected what I refer to as economic and performance characteristics for each technology. This again was primarily driven by

stakeholder data that the staff collected several months ago, and then augmented by our knowledge in the area and then further interviews with stakeholders.

So these are things that will affect the competitiveness of technologies, things including the installed cost, operation and maintenance costs, the capacity factor, and then emissions characteristics for either markets that exist, such as NO_X and SO_X, and then some that might exist in the future, such as carbon.

And some of the things I wanted to note here, we use the phrase summer peak and winter peak. This is just kind of a minor point, but we collected data on the peak output during those seasons as opposed to what's commonly thought of as the demand offset during peak times during those seasons.

And with that, I'll turn it over to Ryan to discuss the currently installed base in Florida.

MR. KATOFSKY: Thanks, Jay. Good morning. I'll just briefly review the data that we collected on the installed renewable energy capacity in Florida. There is approximately 1,600 megawatts installed, and it breaks down as follows: There's about 1.8 megawatts of PV, and that's on the AC output basis, not on the DC rating for the systems. There's close to 1,100 megawatts of solid biomass, and that breaks down --

there's about a dozen waste-to-energy plants burning municipal solid waste generating 520 megawatts. There's close to 200 megawatts using agricultural by-products, and this is primarily the bagasse from the sugar cane industry. These are the fibers that remain after you extract the sugar from the cane.

And then there's about 380 megawatts in the forest products industry, and the bulk of that is what's known as black liquor. This is basically the spent pulping liquors from the paper making process. There's also some -- there will be bark and other solid woody materials, but a lot of that is what's known as black liquor. And I think there was some back and forth on previous calls as to how our number was higher than what was collected through the PSC, and I have a feeling that it's that category of the black liquor where the data was missing from the PSC information. And there's details in the main deck showing you those by unit.

So total solid biomass is about 1,100 megawatts. It's important to note that the municipal solid waste, of course, feeds the grid. The bulk of the other output in that category is used behind the meter. It's industrial cogeneration, and essentially, most of it is used by the facilities that are producing those biomass residues as part of their manufacturing

processes.

There's about 55 megawatts of installed landfill gas capacity, 370 megawatts of existing waste heat capacity, and about 55 megawatts of hydro. So when you add it all up, you get just a little less than 1,600 megawatts.

MR. PAIDIPATI: Okay. Thank you, Ryan. So that concluded Step 2. So Step 3 was working towards what are the technical potentials for these technologies and resources in the State of Florida, so I'm going to go through the solar.

First was PV, photovoltaics. And as I mentioned, we looked at residential rooftop, commercial rooftop, and, ground-mounted, systems.

For rooftop systems, it was really getting at the question of how much rooftop is available in the State of Florida for these systems, because not all of it is accessible for PC. There's items like HVAC systems. Some of the roofs don't face the right direction, et cetera, and there's shading, and then the question of, well, for a given area, how much PV can you actually fit in there. So we worked with various data sources to develop that and had some access factors developed of how much roof space is actually available.

Then we looked at what are the efficiencies of

photovoltaic systems right now, and then what are they likely going to be in the future. So that gave us a number of, by 2020, roughly 52 gigawatts, again of technical potential, not economic potential.

Then ground-mounted systems, we looked at what areas of the state are available that don't have trees, that's not developed for agriculture, that's not a wetland, that's not a forest preserve, that's not a national park, that's not a state park, et cetera, and narrowed it down to a few land use categories. Each water management district, the five water management districts in Florida have land use data, so we conducted a GIS analysis and screened out the land that was not suitable for PV, and then again looked at that question of how much PV can you fit in a given area, and then how will that likely change over time as -- the photovoltaic industry, as you may know, the efficiencies are changing constantly and constantly improving. So that led us to roughly 37 gigawatts again of technical potential by 2020.

Next, concentrating solar power. Here again, we were focusing on this hybrid design of the concentrating solar power system provides heat to the steam cycle, and here we found that the only areas where it really makes sense is, (a), you have to have land

around the facility to do this, because it takes up quite a bit of land. And then it doesn't make sense to do that unless there's a duct firing system installed with the plant, because the power plant needs to be able to change its output over time, depending on whether or not the sun is there or not.

So we worked with the utilities to figure out which facilities are suitable for this, and we also used some public databases and arrived at a number of 380 megawatts, which is quite a bit smaller compared to some of these other solar technologies. But as I described earlier, the solar resource in Florida is not that well suited for concentrating solar power relative to some of the other technologies.

Finally, solar water heating. As I mentioned, our scope of work was only to look at systems greater than 2 megawatts in size, so here we ran into a data issue of -- and this is also a national issue as well. There's not a lot of data on water heating requirements by building type or water heating requirements, usage patterns, et cetera. So as a proxy, we looked at the number of buildings that would likely have a greater than 2 megawatt heating load and came to about a gigawatt of capacity. Again, this is megawatts thermal, so it's not really of electricity, but it's more

megawatts thermal in heat.

So that's the solar technologies. Next I will turn it over to Matt for wind.

MR. STANBERRY: Thanks, Jay. Good morning.

For wind, we looked at two different areas, both onshore and offshore wind development. And as you'll note at the top, there's a relatively large technical potential for offshore wind, and for onshore wind there is some potential potentially for Class 2 resources, although there is a need for a high resolution mapping study to confirm that.

Our method for looking at the onshore resource, we focused on areas identified in a previous report as having the potential for Class 2 resource. We used the water management district GIS data again that Jay mentioned before, looked for land areas that were available within 30 meters of the coast line, because within these areas identified by the report, the report also identified that the potential for utility scale systems was within 300 meters within these areas. And then we applied a wind farm density factor which takes into account the necessary spacing for turbines.

For the offshore resource, we looked at data provided by the National Renewable Energy Laboratory. It's in a prepublication report that they're planning to

come out with in the next month or two. And we looked at the potential both off of the western part of the state and off of eastern part of the state, again conducted a GIS assessment to help us screen down that data based on exclusion factors which cover things like shipping lanes, local opposition to projects within sight of the shoreline, marine sanctuaries and coral reefs.

And with that, I'll hand it over to Ryan to cover the biomass.

MR. KATOFSKY: I hope everybody brought their magnifying glass for this one.

Biomass is quite different from other resources, in that it's a very diverse resource base, and you have to look at each type essentially on its own when you're doing this analysis. But what I like to do is, I like to group biomass resources into three broad categories.

The first category is biomass that essentially you already collect or you generate on-site, and there's four resources in that category.

The first is mill residues. And as I showed just a few minutes ago, the existing sugar and forest products industries already generate several hundred megawatts using those residues. What's shown here is

what's left over. Essentially, the industry uses greater than 99 percent of the residues that it currently produces, so that what's left is only about 2,000 dry tons per year as estimated by the U.S. Forest Service, so very minimal quantities.

The other category, the other resource is municipal solid waste. The estimate here of 15 to 26 million wet tons a year is based on some cases that we developed looking forward to 2020 on how much municipal solid waste might be generated and available on an incremental basis for waste-to-energy facilities, taking into account the fact that the state has a 75 percent recycling goal for 2020.

Another category here is animal waste, and for solid biomass, I just looked at poultry litter and horse manure. There are other animal wastes, but those are covered in the anaerobic digestion category. And for this one, there is about 400- to 800,000 wet tons a year.

And then the last resource in this category are wastewater treatment plant residuals. These are the biosolids that are left over after wastewater treatment. Current uses include land application as fertilizer, or it's even dried and bagged and sold as fertilizer. And there's about 130 to 790 thousand tons, depending on

which types of residuals you consider.

And actually, let me make a quick note. The ranges that are presented for generation and capacity are based on a couple of things. One is the fact that in some of these resource categories, we have ranges of tonnages that are available. The other is that we've assumed a range of efficiencies. As Jay mentioned, there are different conversion technologies for biomass, and they have different efficiencies. And we've applied sort of a low and a high efficiency conversion to bound the technical potential here. So that's why you see ranges, and in some cases, fairly large ranges, because of those two factors.

So those are the biomass resources that are essentially already collected or generated on-site. The largest one there obviously is municipal solid waste. It's a very sizable resource, you know, on the order of 15 to 25 million tons a year by 2020.

The next category is comprised of biomass that is available, but is not currently being collected typically, and logging residues is a very good example of that. These are the tops and limbs and other portions of the tree that are essentially left in the forest through normal harvesting operations. And we used U.S. Forest Service data for 2006. They do

estimate these quantities, and we estimate that at about 2.3 million dry tons per year.

The other one is agricultural residues. This would be things like orchard trimmings, wheat straw, things that are left in the field after harvest. And we have a very wide range there based on a couple of different estimates that had been made. I think this is perhaps one category that deserves some closer evaluation to really understand better what the potential is, I think particularly for things like, you know, citrus orchard trimmings, given that you have a fairly large amount of acreage of that in the state. So that's the second category.

The third category is biomass that is what I term as potentially available. In some cases, this is biomass that is growing today, but is just typically not harvested, or also is comprised of various energy crops, things that you would actually go out and plant for the purpose of producing an energy feedstock. And let me just walk through some of those categories so you understand some of the differences there.

The first two categories are what's called the net change in the volume of trees in the forest. So if you look at a forest, a forest will have growth over the course of the year, and then there will be removals

through timber operations. And essentially, the difference between the net growth and the removals is what's known as the net change. And if that number is positive, it means that the forest added more biomass than was removed, and if that's the case, then that biomass is theoretically available for use.

And then there are some terminology issues with Forest Service data. There's something called the growing stock, and these are trees that are considered commercial species of sufficient quality for the timber industry, and then there is nongrowing stock, which is sort of everything else in the forest, if you will, noncommercial species or deformed trees or rough trees, things that don't have a commercial value. And between the two of those categories, there's about 4 million dry tons per year currently accumulating in the forest.

I think it's important to note that this number is expected to decrease in the future, all else equal, for a couple of reasons. The main reason is that the rate of tree planting peaked in the late '80s and has declined quite a bit since then, which means that the trees that were planted in the late '80s are being harvested now, and there weren't as many trees planted since then, so forest growth is going to decrease, all else equal. And, of course, there's interest in

bioenergy development today that's not reflected in this 2006 data, so as those plants come on line, that may decrease this number. But currently the forest is producing a net positive growth.

The remaining categories are different forms of energy crops. One option is to take existing planted pine forest and apply more intensive management to increase growth rates for greater biomass production, and then other options are to plant other types of energy crops, whether it's Eucalyptus or perennial grasses or energy cane on various types of land. We looked at the reclaimed phosphate mining land and existing farmland. And as you can see, if you compare the numbers, it's really the energy crops that provide very significant potential. Of course, it will take time to realize that potential because you have to have people incentivized to plant those, and then it takes time to grow that material.

So when you add all that up, you've got a technical potential ranging from about 6 gigawatts to close to 14 gigawatts of capacity.

There's a couple of other categories where we looked, but didn't find enough data. One is what's termed the forest understory. This might be small diameter trees, shrubs, other things that are growing in

the forest that are potentially available. And there is a study that's starting with the Division of Forestry and the University of Florida that's going to try and look at this in a bit more detail.

And then the last one is algae. There's a lot of interest in algae for biodiesel production as a transportation fuel. But by weight, the algae that grows is about 30 or 40 percent oils, which is what's used for the biodiesel production, so the remaining biomass that grows in this algae is potentially available for other uses, one of which would be electricity generation. This technology is still in development, and the scale of how it would be deployed is still highly uncertain, but something to monitor and try to understand a little bit better as time goes on.

So that's the summary of the biomass technical potential.

MR. PAIDIPATI: All right. Thank you, Ryan.

So for the remaining technologies we looked at, the first was landfill gas. And if you recall, there's currently 55 megawatts of nameplate capacity already developed in the state, so we looked at the potential for new landfill gas to energy sites, and here we used state data from the Florida Department of Environmental Protection, and then the federal, the EPA

have data. They maintain databases on potential sites for new landfill gas, and that came to 100 megawatts by 2020.

Next is what we call anaerobic digester gas, gas that is used for energy production resulting from anaerobic processes. The staff's draft legislation listed three main sources, farm waste, wastewater treatment facilities, and then food waste. Food waste generally is used -- has other purposes, competing uses right now in the state, so that wasn't one we looked at. But we looked at farm waste and wastewater treatment facilities, again with various federal and state data sources. That only came to about 35 megawatts of technical potential by 2020.

Next is waste heat, as I mentioned, resulting from the -- that can be used to generate electricity resulting from the sulfuric acid conversion processes, and we worked in the trade group in the state in that area to develop a technical potential of new capacity of 140 megawatts.

Then finally was the ocean category. If you recall, there were four technologies I discussed. The first was wave energy. And there is a lot of activity going on worldwide, but it's happening in areas that have a higher wave resource than off the coast of

Florida. So within the 2020 time frame, those technologies really aren't going to be optimized for the wave resources off the coast of Florida, so we didn't see that going in in the time frame of the study.

The next was ocean thermal electric conversion. Again, there, there is activity happening throughout the world, but given the resources off Florida, it's most likely that the development is going to take place in other places. And really, given the time line required for development, it's not going to happen by 2020.

The third was tidal conversion, which again relies on areas where there's a high tide, and that really isn't present in Florida.

But the last technology, current, ocean current, has actually a very large potential. But given the time frame of the study, 2020, we worked with Florida Atlantic University and developed really only a technical potential of 750 megawatts by 2020. That number will grow past that point, because as you may know, the currents off the coast of Florida in the Gulf Stream are quite strong and pretty stable as well.

So before we move on to the next section, I just wanted to recap. Some of the larger technologies, technologies with the larger technical potential are PV,

offshore wind, and solid biomass. I just wanted to keep that in everyone's mind before we go forward.

MR. STANBERRY: All right. Now I'll walk you through the process of developing scenarios. As I start, this is Step 4 in our process. As I start, I want to reiterate a point that Jay made before. Scenarios are not a tool for a forecast. They do not predict the actual value.

What we did was devise three scenarios. And the creation of scenarios is a bit of an art form, and one of the best ways to do it is to look at the most important drivers for renewable energy adoption. And if you look at the graph presented, this is one of the better ways to help determine what those key drivers are. And if you look at that Y axis, you're looking at the drivers -- the relative impact of drivers on renewable energy adoption, and if you look at the X axis, you're looking at the relative uncertainty surrounding the actual values that those drivers will take.

So to give you an example, for clarity, fossil fuel prices is a great place to look. They clearly have a very large impact on renewable energy adoption, but there's very little certainty, as we've seen over the last six months, about the actual prices that those

fossil fuels will take.

So if you look in the upper right-hand corner of your graph, those are the five drivers that we have identified as the most important drivers for renewable energy adoption going forward, and they include fossil fuel prices, greenhouse gas policy, the credit markets, which looks at both the cost of debt and equity, as well as the availability of debt. This is an issue that has arisen within the last six months and has important consequences. And then we look at renewable energy financial incentives, both at the state and federal level, always an important driver for renewables, and then the renewable energy regulatory framework, which primarily covers the design of the RPS.

So if you flip then to the next slide, how do you take these key drivers and turn them into scenarios? You look at how you can attach values under the different scenarios to variables within those drivers. So just at the broad level, what we're doing here is creating three scenarios, one of which is a scenario which is more favorable for renewable energy adoption, one of which is a mid case, and the final, which is a relatively less favorable scenario for renewable adoption.

So to get into how the actual values are

placed for these variables within the drivers, let's look at CO_2 pricing under greenhouse gas policy. Essentially, what we're doing here is assigning different values to the price of carbon under the different scenarios. Again, we're not making -- one important point here is that we're not making judgment on how that price will be created, whether it's a federal cap and trade, any sort of state level action. What we're doing is actually just assigning the price of carbon under the different scenarios.

So then the other key ones, as mentioned before, were credit markets, which Jay will cover on the next slide in a little more detail, fossil fuel costs, which were primarily derived from stakeholder data from the utilities that present different prices for natural gas and coal, and then a range of renewable energy financial incentives. This includes primarily the federal investment tax credit, the federal production tax credit, and a suite of state programs. And then the final is the renewable energy regulatory framework, which, as I mentioned before, focuses primarily on the RPS.

And one thing to note here is that we're looking at a variance in what the REC spending cap is under the scenarios, and one important subnote to that

is, again, as Jay mentioned before, we're looking at a situation where 75 percent of the REC expenditures are determined for Class 1 resources, wind and solar, and 25 percent of the expenditures are for the Class 2 resources.

And with that, I will turn it over to Jay for a little more detail on the credit markets.

MR. PAIDIPATI: Great. Thanks, Matt.

So as Matt mentioned, the availability of credit influences -- in turn influences the levelized cost of electricity, of renewable energy, which then influences their competitiveness. So that can be looked at in two ways. First is the cost of debt from banks. As credit markets get tighter, the cost of debt goes up. The same thing with the cost of equity. Especially in certain technologies, tax credit investors get in for the tax equity. And then also the availability of debt or how much debt a project developer could get for a project is influenced by the availability of credit. Now, that varies across scenarios.

Then also we looked at, by technology, investors, both banks and equity investors usually have higher rate of return requirements for a technology given its stage of development. So I won't go through each one, but we looked at a range across the scenarios

and across technologies.

Okay. Ryan will go to the next slide.

MR. KATOFSKY: Thanks, Jay.

There are some other variables that need to be considered in the different scenarios. These are not drivers as Matt has defined them, but are still inputs that require some values so that we can conduct the analysis, and they relate primarily to the biomass.

The first is how much of that technical potential is considered accessible. And we basically just looked at each of the individual resource types and applied some percentages, if you will, to the different categories to come up with a low, medium, and high biomass availability by the three scenarios. There's also the cost of that biomass, and we varied that price from a low of $40 a dry ton to $60 a dry ton. And here the logic was that in a favorable scenario, there's going to be higher demand for biomass, which would tend to drive the price higher. And just to give you a sense of what these numbers mean, $40 a dry ton is roughly $2.50 a million Btu, just to give you a rough conversion.

We also looked at a range for the tipping fee for municipal solid waste. And it's important to note that for this feedstock, a tipping fee is actually a

revenue for the waste-to-energy plant, not a fuel cost. And we looked at historical data for Florida, and talked with some people as well, and came up with a range here of 30 to $70 a ton. Again, the idea here in a scenario more favorable to renewable development, there would be higher tipping fees because there was perhaps a desire or a policy that would create more incentives for waste-to-energy implementation.

And then Jay also talked about technology adoption, and I think Matt is going to go into this in a bit more detail later, but we have three different technology adoption curves, one that takes a longer time view, a mid time view, and a short time view, to achieve the saturation of that market potential.

MR. PAIDIPATI: Okay. Thanks, Ryan.

So now we've gone through and defined -- we've defined the technical potentials, we've defined the scenarios, so the next step is to look at, well, how does renewable energy compete in these various scenarios. So for all technologies except for the customer-sited PV, which I'll discuss in a second, we compared the levelized cost of electricity of that renewable energy technology to that of the traditional technology it would likely compete against and assumed that adoption really started when the renewable energy

technology's LCOE was less than that of the competing traditional technology's LCOE, and we used combined cycle plants, combustion turbine plants, et cetera.

And there's two I want to note. One is anaerobic digester gas technologies at wastewater treatment plants and farm waste facilities. That's really not competing on the wholesale market. It's competing against grid-supplied electricity.

And then solar water heating, again, when you look at 2 megawatts and above, it's typically a gas-fired boiler, and right now, in that industry, the average efficiency is about 80 percent efficient, so we compared the economics of a solar water heating system to that of a natural gas-fired heater.

Okay. So that's the levelized cost of electricity. We used that for all technologies except for customer-sited PV. As I discussed earlier, what we found is the best way to look at adoption is again looking at the simple payback, because certain segments of the market are willing to adopt PV at a higher payback, because there is a certain amount of demand elasticity. So we have a market penetration we've developed over several years, and this takes into account several things that influence payback, like installed costs, the incentives, both state and federal,

the output of the PV system, taking into account the solar resources in Florida, the load required by the building. And then we also got utility rate profiles from each utility and accounted for things like time-of-use rates, seasonal changes in rates, et cetera.

So folding that all together, you get a simple payback by different scenario. And then we used what I referred to as a payback acceptance curve that looks at, for a given payback period, what percentage of the market will likely adopt, and then we varied that across -- we ran this model for each scenario to develop what would likely be the market penetration of customer-sited PV in each case.

And as I mentioned earlier, just because the technology becomes competitive on a certain day doesn't mean everyone is going to go out and adopt it that day. There's what I would think of as a certain amount of inertia to do this. You know, the supply isn't there to meet the demand. There could be certain barriers, noneconomic barriers that take time to develop, to get worked out.

So the best way we found to do this is to use technology adoption curves, or in some other industries it's called S-curves, that estimate the diffusion based upon characteristics of the technology the market is

playing with, et cetera.

So the factors we focused on for each technology is the level of past development, because if a supply chain already exists, ramping up development can be much quicker and easier. Then the technology risk is investors' and consumers' perception of risk about the technology might create a longer time horizon for development. And then the third one is barriers or complexity in the technology's market, whether it be technical, economic, et cetera.

So taking those three things into account, we used a family of technology adoption curves referred to as Fisher and Pry, named after two economists that looked at this at one point. And it's an empirically based model that looks at other similar industries, where it's a substitution effect, where a consumer or investor is replacing one technology with another, so here it was replacing a traditional technology with a renewable technology. And we assumed that -- you have to start somewhere with the curve, because you see it's a function of years of introduction on the right.

So for technologies that really aren't in the Florida market yet, we assumed that that curve was anchored, if you will, in the year when the technology becomes economic. But there are some technologies we've

discussed, like waste heat, landfill gas, solid biomass, that are already present in Florida, so we used when those technologies really started in Florida as the anchor year, if you will.

Okay. So now that brings us to -- so just to recap where we've come from, we looked at what technologies we're going to look at, the economic characteristics of those technologies, the scenarios to look at them in, and then the technical potentials, and then looked at the competitiveness, and then applied these technology adoption curves.

So here's what it gets you. This is nameplate capacity of adoption in Florida under the various scenarios, and you can see there's quite a bit of range, as you might imagine, by the different scenarios, ranging from in the unfavorable scenario without RECs, not a lot of additional adoption, to in the most favorable scenario with an RPS, of in the neighborhood of 18 gigawatts.

And what this is comprised of, if you recall earlier, I mentioned that the primary technical potentials lie in solid biomass, PV, and wind. Again, the actual projected nameplate capacities mostly comprised of solar, biomass, and in some cases, onshore and even offshore wind as well.

I guess there's a lot here to look at, but I guess those are probably some of the main takeaways, is that there is a very large range of potential adoption.

Okay. Going on to what does that mean in terms of an RPS, the staff provided us with projections of the four IOUs' retail sales, and we folded in the capacity factor data of how much will a given renewable technology actually generate over the course of a year and figured out what that was in gigawatt-hours and then compared that to the projection of retail sales provided by the PSC staff. And again, as you might imagine, the bounds are pretty large, again, from not much extra development of renewables to approaching 27 percent renewables by 2020. And again, a lot of this is driven by solar and wind, but again, that's partially reflected by the structure of the draft ruling that we have thus far, or the draft legislation we have thus far of 75 percent of the RECs going towards solar and wind, so that helps drive that to some degree, but then also the biomass technologies are in there.

So if you recall, we looked at all these scenarios with and without RECs to understand, well, what does an RPS do, how much extra generation does that get you. So here is by the different scenarios the REC expenditures, which are set at -- there's a ceiling, a

cap, if you will, again, as we mentioned, based upon the percentage of the retail sales of the IOUs, so you can see that here on the top line of each graph. And then the second line is, well, how much extra generation does that get you. So it ranges from about 2 gigawatt-hours in the unfavorable case up to 23 gigawatt-hours in the high case. So again, there's a large range of where that gets us.

Oh, I'm sorry. Yes, that's terawatt-hours, not gigawatt-hours.

So some key takeaways we got from this, we found that wind technologies, given the resource characteristics, as Matt mentioned, really are in the Class 2 range onshore and then higher offshore, but the costs are greater offshore. They really came into play under the RPS as it's drafted now not to say that wind shouldn't be developed in Florida, but just that it generally would require some level of subsidy to compete relative to traditional costs.

Now, there are some technologies, though, that were competitive in all cases with or without RECs, and these are things that are currently -- waste heat and landfill gas, that are already present in Florida. They're already operating. They've already been developed. And there are some other ones, repowering

coal facilities with biomass, or what's called co-firing biomass, we didn't discuss it too much today, but there's discussion of that in the full report. And then some of the anaerobic digester facilities and wastewater treatment plants, those are competitive in all cases.

Ground-mounted PV is another one, with the exception of the unfavorable without RECs, we have ground-mounted PV going in in all scenarios by 2020.

And then another interesting thing we found was that because of the structure of 75 percent of the RECs going towards wind and solar and the remaining 25 percent going towards the other technology, combined with the fact that there are, as Ryan discussed, on the order of 1.5 gigawatts of renewables, primarily which are Class 2, biomass, waste heat, et cetera, the demand, if you will, or the pool of Class 2 renewables was such that the REC price wasn't very high and didn't create a very large impact in those cases, just because of how the draft legislation is structured right now.

And then the last point I wanted to emphasize is that, as you mentioned several times, solar water heating systems less than 2 megawatts are not covered by the study, but could potentially be an important part of an RPS in Florida. Unfortunately, that study that's looking at that, less than 2 megawatts, is somewhat in

parallel with our study, but the results are actually due after our study is done. So when looking at this, it's important to understand that there could be a potential -- there will be a potential from solar water heating less than 2 megawatts, which would in turn -- it's hard to say what that would do. It might bring down the REC price for Class 1 renewables, but it might not, and it would create overall more renewable energy in Florida likely. But again, the results of that study aren't due for several more weeks.

I think with that, that was the extent of the executive summary we wanted to discuss, so, Cindy, I'm not sure what the next step is.

CHAIRMAN CARTER: Commissioners, at this point in time, we're going to defer to the bench, and then Commissioners will have their questions, and after we've finished our questions, we'll go to staff, and then we'll go to the stakeholders. Is that our order, Cindy?

MS. MILLER: Mr. Chairman, at some point we were suggesting a break. I don't know if you want it now.

CHAIRMAN CARTER: Oh, yes, that's right. We've only got one court reporter. Why don't we -- this seems like a good breaking point, since these guys have just finished their presentation, by the way, gentlemen.

Let's take a break now, and then when we come back, we'll start with questions from the bench, and then we'll go with questions from staff, and after questions from staff, we'll go with questions from the stakeholders. Okay? We'll come back at quarter of by the clock on my left. We're on recess.

(Short recess.)

CHAIRMAN CARTER: Would you take your seats, please. We are back on the record, and when we left, we were getting ready to go into the questioning by the Commissioners, and then we'll go with questioning by the staff. After staff completes their questions, I'll ask you to give directions to the stakeholders as they come up to make their questions and all. So at this point in time, Commissioners, we're back to the bench, and we'll start with questions here.

Why don't we just -- you want to just defer to staff first, and we'll come back to the bench?

Staff, you're recognized.

MR. FUTRELL: Thank you, Mr. Chairman. I'm Mark Futrell with the Commission staff, and I've got a few questions for Navigant Consulting staff that worked on the project.

In developing a draft RPS rule, the Florida Statutes on RPS, Section 366.92, requires the Commission

to assess the availability and levelized costs of renewables through 2020. And in your opinion, does this report provide that information?

MR. PAIDIPATI: Yes, it does.

MR. FUTRELL: Thank you. Now, in the second phase of the study, the first phase being the technical potential, which was, as we understand it, a fairly unconstrained view of the potential for renewables, in the second phase, you compared the cost of renewables to traditional utility generation technologies with similar performance characteristics; is that correct?

MR. PAIDIPATI: That's correct.

MR. FUTRELL: Okay. And this exercise would be similar to a screening analysis that is normally done in planning, where the capacity costs of renewable generating technologies are compared to like, traditional technologies. For example, a resource that is primarily peak intensive like solar would be compared to combustion turbine, and a biomass resource that may be intermediate or base load in nature would be compared to a coal or a nuclear unit; is that correct?

MR. PAIDIPATI: That's correct, yes.

MR. FUTRELL: Okay. Now, if we could go to -- I think you guys may have the clicker. If you could go to slide 16 -- I'm sorry, 15. And again, this is where

you're getting into the scenarios that you used to analyze, further analyze the economic potential of renewables. Would you agree that in what you did, the fossil fuel price impact has the greatest potential impact on renewable development?

MR. PAIDIPATI: Yes, that's true.

MR. FUTRELL: Okay. And that would be followed by these other variables as far as their relative impact on renewable potential development?

MR. PAIDIPATI: Correct.

MR. FUTRELL: Okay. And then on slide 16, if you go to the next slide, here we see again, as you described, the scenarios with the -- the three scenarios with the various drivers you've got. These drivers and the values you assigned to the drivers would be considered fixed, in that you didn't do any kind of cross-checking of, for example, allowing the greenhouse gas price to stay low, whereas the fossil price to increase, or REC prices to go into --

MR. PAIDIPATI: Correct. I would refer to that as a sensitivity analysis, and unfortunately, that was outside the scope of work that we looked at, was to do what we call a sensitivity analysis, or some call it -- you could think of it as a Monte Carlo analysis, if you will, where you vary lots of different variables and

see what shakes out, if you will. We just looked at just these scenarios as defined.

MR. FUTRELL: Okay. Now, in calculating the levelized costs for the various renewables in the report, as I understand it, and correct me if I'm wrong, the levelized costs you arrived at represent the rate required by the renewable developer to meet equity and debt requirements and essentially stay in business; is that correct.

MR. PAIDIPATI: That's correct, yes.

MR. FUTRELL: Okay. Now if we could go to page 21 of the executive summary. Now, here you show the potential nameplate capacity that could be developed under the various scenarios with and without RECs. Would you agree that this estimate of capacity does not take into consideration Florida's existing generation mix of traditional utility generation, renewables, and other resources?

MR. PAIDIPATI: Correct, yes. At the beginning of the presentation, I tried to emphasize that this was not an integrated resource planning process. This was looking at the bounds of what could happen underneath the scenarios we developed.

MR. FUTRELL: And it doesn't take into consideration the need for power?

MR. PAIDIPATI: Correct, correct.

MR. FUTRELL: Now, finally, if we could go to page 22 -- and this will be my last question. Again, this shows renewable energy as percentage of the utility's retail sales under various scenarios; correct?

MR. PAIDIPATI: Correct.

MR. FUTRELL: And so this shows that approximately -- the favorable scenario with RECs would be approximately 20 percent in 2020.

MR. PAIDIPATI: 27 percent, yes.

MR. FUTRELL: And that would require all the drivers in that scenario to occur?

MR. PAIDIPATI: To occur, correct, yes, the favorable scenario where every variable is -- or every factor unfolds as we've defined it in the favorable scenario, yes.

MR. FUTRELL: And another observation would be that the next line at 2020 would be the favorable without RECs. So that shows a differential of -- again, it gives you a relative sense of the impact RECs would have on the potential for renewables?

MR. PAIDIPATI: Correct.

MR. TRAPP: Thank you, Jay. Bob Trapp, Commission staff.

Could I turn your attention to slide 24,

please?

MR. PAIDIPATI: Okay.

MR. TRAPP: This shows key results of your analysis, and it seems to indicate that different renewable technologies require different levels of cost or contract costs in order to go into business. Does that lead one to the conclusion that perhaps a sound policy to both encourage renewables, while at the same time minimizing cost to ratepayers, might lead one to a scenario of contracts available out there at different pricing levels matched more or less to the needs, the cost needs of each type of renewable?

MR. PAIDIPATI: I would say that's definitely a method used in other parts of the country that might be of interest to Florida. I wouldn't say we can endorse one methodology or not. But, yes, it indicates that, obviously, each of these technologies has inherently different characteristics, whether it be capacity factor, installed cost, et cetera, that lead them to have different levelized costs of electricity.

MR. TRAPP: Thank you.

MS. MILLER: Mr. Chairman, what we thought was that the stakeholders who have questions could come up to the microphones. And we need you to identify your name and who you're with for our court reporter. Also,

we need you to be considerate of the fact that we have many of you, and so we can't just have unlimited questions. We thought we would just start at one end and go down the row if that works.

MS. CLARK: Mr. Chairman, I'm Susan Clark. I'm with the law firm of Rady, Thomas, Yon & Clark, and I'm here on behalf of four of the IOUs, Tampa Electric Company, Progress Energy, Gulf Power, and Florida Power & Light. And we do have some questions that we would like to ask.

First, I would like to make some introductory remarks. First, we would like to thank Navigant Consulting for its technical assessment report. We recognize the effort involved in compiling this large amount of data in a short period of time, and we expect that Navigant will proceed with its limited scope report and do a responsible report on the renewable energy potential and penetration in Florida.

We do have a number of questions based on Navigant's previous draft and the most recent draft, which we had made available to us right before the Thanksgiving holiday.

For example, we have questions regarding Navigant's apparent assumption that very large quantities of offshore wind generation can be

constructed in Florida, despite the fact that there is no offshore wind generation as yet built or even begun in the U.S. And we have questions regarding the availability of land for the projection of 74- to 83,000 gigawatts-hours of PV, just to name a few.

Therefore, at the appropriate time, we would like to understand from you all and from the staff what the process will be going forward in responding to the questions we have, and we would like an opportunity to ask further questions based on -- once we have a more thorough review of this most recent draft.

I would point out that through the process so far, the opportunity to ask the questions has resulted in improvements in the report, and we believe it will make it a more useful tool.

In the interest of saving time today, we have a written list of questions that relate to assumptions, calculations, and methodologies which I will point out -- which I will pass out to everyone rather than ask them here today. The technical potential and economics associated with each resource cannot be verified or compared to other estimates of the technical or economic potential for these various resources without this information, and we hope Navigant can provide the needed data to confirm their calculations.

Finally, before asking our specific questions, I do want to comment on the scope of Navigant's report. And they did cover this on their slide 4 that they just spoke to you about. The study scope is limited, and it is imperative to include all critical utility planning variables when determining the feasibility of renewable technologies in Florida, and I think one of staff's questions touched on this. Integrated resource planning, transmission loading, and cost impacts and system operations will ultimately affect our system reliability, and these things will need to be included when assessing the viability of any technology in Florida.

With that, I'll turn to my oral questions that I have. And some of these, as I listened to Navigant's report, I think they touched on those, so it might be a quick process here.

One thing I would like clarification on, and I noticed it in what they said today and in their draft. They referred to staff's draft legislation. I take that to mean staff's rule.

MR. PAIDIPATI: That's correct. We should have said staff's draft rule, that's correct, yes.

MS. MILLER: Mr. Chairman, we're trying to think about how this will fit into the record because of

the time frame. It could be that it could be filed in the post-workshop comments, although that's a very short turnaround there. The post-workshop comments will be due on the 8th. So I'm not sure if -- since these aren't being asked and answered here, how this will fit. I mean, it may be that Navigant could respond in writing or -- Mark?

CHAIRMAN CARTER: I don't know how that would impact on our schedule.

MR. FUTRELL: Mr. Chairman, if I may.

CHAIRMAN CARTER: You're recognized.

MR. FUTRELL: Certainly, we don't have a problem with parties,if they want to submit questions to Navigant Consulting staff and Jay's team, and they can take those questions under consideration and utilize the information, the points you're bringing up. As you mentioned, some of the questions that have been raised have helped focus the report, and some of the revisions.

Again, the major part of the report and the work is completed, but I don't think Navigant Consulting would have a problem with considering some of the questions, and then to the extent they can, work some of that into the final report submitted and due on January 1st. They can do that to the extent that it's appropriate.

MR. TRAPP: If I could add to that, Mr. Chairman.

CHAIRMAN CARTER: Mr. Trapp.

MR. TRAPP: You know, this study has been basically publicly funded by the DOE, and we are close to the limits of what that funding will allow. So I would encourage the parties to try to focus their questions, not get into an elaborate discovery process of extracting every piece of information that was used by Navigant. If we can get to real focused questions, that would be very helpful, both for us and for them, because of time and money.

CHAIRMAN CARTER: Thank you, Mr. Trapp. And we do -- in these times that we're under, we are not in a position to go over budget by any stretch of the imagination. We've had several workshops. We've had open dialogue with our staff. I mean, the questions presented, we can look at those, but we're not going to go over budget, and we're going to keep our time schedule. We've got to adhere to our time schedule. The Legislature has given us a mandate, and we will meet it. We'll get to them. We've got a schedule. We added this workshop as an additional -- it was not necessarily on the schedule, but we added it for times like this. So as much as possible, if we can kind of drill down to

what our specific issues are, we can take those into consideration. But we will stay on schedule, we'll stay on task, and we will stay on budget.

With that, Ms. Miller.

MS. CLARK: Yes. We do have some questions that we would like to ask now that we thought had quick answers to them. You know, what I passed out to you was more or less asking for some of the data that they relied on, and hopefully that will not be burdensome. It will be simply a matter of directing the utilities to where that information can be found.

CHAIRMAN CARTER: I don't think there will be a problem with them giving it if you're requesting for like citations for different aspects that are within the document itself. Okay. That's not a problem.

MS. CLARK: With that, we do have a couple of questions on the solar. We had a question about the estimate of the availability of 600 square miles for the solar potential. Our question is whether Navigant's report takes into account the fact that most of the open undeveloped land in Florida is not available because it is either wetlands, part of the groundwater resource percolation areas, or is home to protected species. And when I listened to your report, I heard you touch on some of those things, so if you could elaborate a little

bit more on how you came up with that 600 square miles.

MR. PAIDIPATI: Yes. We specifically screened out areas such as wetlands, natural reserves, and some of the other areas you mentioned. And we also looked at, in addition to open land, abandoned mining lands as well. So we tried -- we screened out those areas in question.

MS. CLARK: Is that information of what you screened out easily available?

MR. PAIDIPATI: Yes. We have a table in the back of the report, in the appendix, that the water management districts have 152 land use codes, and we specifically cite which ones we used for solar and which ones we did not, so I would refer you to that table to do that, yes.

MS. CLARK: All right. And you may have answered this question as well. This was the question on using the solar generated steam to augment the output of the natural gas combined cycle, and as you indicated, you need duct heating to do that.

MR. PAIDIPATI: Yes.

MS. CLARK: Now, our question is, did you screen out those that don't have duct heating?

MR. PAIDIPATI: Yes, yes, yes.

MS. CLARK: And do you have that information

so we can compare it with our information as to what plants have that and what plants don't?

MR. PAIDIPATI: Some of that information was given to me directly from the utilities, so I'll have to discuss it with them before I can publicly cite that information.

MS. CLARK: Okay.

MR. PAIDIPATI: You're obviously representing the utilities. So I will discuss that with them each individually, because I don't want to divulge any confidential information.

MS. CLARK: I would appreciate that.

MR. PAIDIPATI: Okay. Sure, sure.

MS. CLARK: Turning to wind -- and you may have answered this as well. I think you indicated -- I thought I heard 300 meters offshore. How far out do you --

MR. STANBERRY: That's onshore. Sorry.

MS. CLARK: All right. Well, let me ask you this. How far out did you consider the offshore facilities to be sited, and is it still within an area that can be determined a Florida resource? In other words, how far out do you go before it's no longer a Florida resource?

MR. STANBERRY: The distinction that we made

was based on depth, because that is how the resource or the technology is screened in terms of when it will be available. And so through a variety of discussions with developers and regulators and folks in the R&D business, the estimate is that by 2020, you'll be able to go out to 60 meters in depth. Now, that is not a distance from shore marker, but rather a depth from the level of the top of the ocean down to the seabed. And I think Jay probably has a comment on what's in-state.

MR. PAIDIPATI: Yes. I would refer that question back to the PSC staff in terms of what will qualify as Florida. Generally international boundary waters are, I believe, 12 miles, and state boundary waters are usually three miles. So I would refer that back to the staff and how that's decided upon in the legislation.

MS. CLARK: Well, then just so I'm clear, whatever you have cited for offshore wind, you don't know if it's in or outside of the boundary, because you only looked at the depth?

MR. STANBERRY: We didn't screen for that, because it depends on how the actual regulation would be written as to what would count towards the RPS. So we haven't screened out that beyond the state boundaries.

MS. CLARK: Maybe I asked my question wrong.

Because you used a different method of determining what would be available, you have no way of telling if it would be within the boundary or not.

MR. STANBERRY: I actually have some information on distances for the different technical potentials. I actually sent that over to a couple of the utilities, and I can absolutely make that available to you.

MS. CLARK: Okay. Thank you.

MR. STANBERRY: Sure.

MS. CLARK: Now, turning to the biomass, it appears to us that there was an assumption made that biomass emits no CO_2; is that correct?

MR. KATOFSKY: The biomass that's consumed in the plant, assuming that over some time frame is grown back, would have essentially net zero CO_2. Now, there would be some CO_2 associated with trucking and other things, other activities, but this study was not a life cycle assessment of biomass, so we didn't get into that. We just assumed that for the plant itself, it's essentially carbon neutral.

MS. CLARK: But you wouldn't know if it emits CO_2 if it's going to be subject to regulations?

MR. KATOFSKY: Oh, in terms of, for example, if there was a cost of carbon, you mean?

MS. CLARK: Right. If there were a cap-and-trade on greenhouse gases, presumably if it emits CO_2, it would be subject to the cap-and-trade.

MR. KATOFSKY: Not necessarily. Biomass is looked at a little bit differently than other combustible fuels because of this issue of basically the growing biomass is reabsorbing carbon dioxide. So it -- I don't think there's a simple yes or no answer to that one.

MS. CLARK: But your assumption of this is zero CO_2 emissions for biomass?

MR. KATOFSKY: Correct.

MS. CLARK: Okay. Did you take into account the use of groundwater for drinking and potable purposes? It's my understanding that a great deal of groundwater is used for those purposes, and it is our view that the biomass crops that require water will directly compete for this limited resource, and therefore, your estimates of the biomass may be overstated.

MR. KATOFSKY: Generally speaking, if you're growing bioenergy crops for energy production, you're selecting varieties that do not require substantial irrigation, so you're picking varieties that are suitable for the region in which they're being grown.

MS. CLARK: So I take it you assume no competition between what is needed for drinking water and potable purposes with the biomass product.

MR. KATOFSKY: That's correct.

MS. CLARK: Okay. You may know right now, or maybe you can provide it later, what is the basis for your conclusion that 14 percent of total farmland in the state for biomass crop is feasible.

MR. KATOFSKY: I looked at total farmland in the state and just made assumptions about how much of that could be converted to energy crop production. There's -- I think it remains to be seen how much of that land ultimately would be converted. The bulk of the land in farms, however, is rangeland and pasture and woodland as opposed to acreage that's harvested on an annual basis, so there's a fair bit of land that could be potentially converted.

MS. CLARK: Can you provide us the assumptions you used to come to that 14 percent?

MR. KATOFSKY: There might be -- there are some details in the report, but I think we can probably get you the additional details.

MS. MILLER: Ms. Clark, maybe we could proceed down the line and then come back around, depending on our time frame.

MS. CLARK: Okay. So you want to move on --

MS. MILLER: Uh-huh.

MS. CLARK: -- and give me a chance -- all right. I can ask them later.

MS. MILLER: That sounds good.

MS. BROWNLESS: Good morning. I'm Suzanne Brownless here today on behalf of the Florida Solar Coalition. And with me is Gwen Rose from Vote Solar Initiative, a member of the coalition, and Gwen will be asking our questions this morning.

MS. ROSE: Hello. Thank you for the opportunity to participate today. I wanted to make a few observations and then ask a couple of quick questions. First, we're really, I think, heartened by the fact that the study shows that there is obviously enough technical potential to get to a goal of 20 percent by 2020, but more importantly, that it shows that with appropriately supportive policies, a 20 percent by 2020 goal is economically achievable. Just consider that under the mid favorable and favorable scenarios with RECs, meaning with an RPS, Navigant demonstrates that Florida could obtain 12 percent to 27 percent renewables for a rate impact of 2 percent to 5 percent.

The Florida Solar Coalition performed an

analysis. We approached it very different, but we found fairly similar results, that you could get 20 percent by 2020 with about a 4 percent rate impact.

Again, we've noted in the past that we strongly believe that solar hot water under 2 megawatts should be included in the technical and economic analysis. It's eligible to participate in the RPS and should lower the overall cost of getting to that goal.

Generally, we are supportive of the projections for costs and capacity potential under mid favorable and favorable RPS scenarios, but I do have a couple of questions about some of the assumptions used.

And we also just wanted to point out that -- again, Navigant said this, but they use -- they assume that each renewable technology will displace a conventional resource whose output most closely matches the renewable output, so as such, Navigant assumes that solar displaces gas-fired combustion peaking generation. And it's a common thing for people to assume that solar should be compared to base load resources. There have been a few media stories that have done this in the past few weeks. However, we believe that Navigant's approach is more appropriate and rightly recognizes that solar is an important peaking resource.

And to that point, I don't know if you want to

refer to specific slides, but if you look at the levelized cost of energy for renewables with RECs for the mid favorable and favorable scenarios, PV is 14 to 13 cents a kilowatt-hour compared with 21 to 28 cents a kilowatt-hour for a peaking resource, so it's already more competitive than a peaking plant. In the mid favorable scenario, PV is 12 to 21 cents a kilowatt-hour compared with 17 to 23 cents, so again, in the mid favorable scenario, it's also more competitive, unless I'm misinterpreting that. Let me know. So, in other words, solar is competitive with peaking plants.

I think that's generally my comments.

Questions for Navigant that I think are probably easily answered, you use an assumption about the capacity factor for peaker plants that's, I think, 15 percent. I would just note that in California it's 5 percent. Some similar analysis that we've done or seen for the levelized cost of electricity has been around 10 percent. So I'm wondering if you can tell us why you used 15 percent and what you think that would --

MR. PAIDIPATI: We went with the upper end of the range to be conservative, because going forward, it's not easy to tell how the peaking resources will be needed in the State of Florida, given its load profile, so we went with the upper end of the range. Obviously,

the range is generally between 5 and 15 percent. We went with the upper end. We saw in the ten-year site plan a large amount of peaking facilities going in in Florida and decided to use the upper end of the range, under the assumption that potentially the peaking loads would go up over time in Florida.

MS. ROSE: Okay. On slide 15, when you talk about key drivers, there is an assumption about the renewable energy adoption in relation to transmission investment, and I'm just wondering -- you know, the benefits of photovoltaics and solar hot water in terms of, you know, when it's sited at the distribution level, it reduces transmission losses and can in some cases help defer transmission and distribution investment. But you note there that it has a low impact, so I'm just wondering if you could expand on that.

MR. PAIDIPATI: This is more on the investment in transmission affecting the availability of renewable energy.

MS. ROSE: Oh, okay.

MR. PAIDIPATI: Yeah, yeah, not the impact of renewable energy on transmission. Looking at these what I call T&D type effects was outside the scope of our study, but definitely, I think if you looked further on, there would be impacts of PV on those types of issues.

MS. ROSE: Right. The studies I've seen in other states -- I don't think it has been done for Florida -- do assign a pretty high value to the benefit of photovoltaics to reduce transmission and distribution benefits.

The last question, I'm wondering if you could clarify. Your analysis seems to really heavily favor central station photovoltaics over distributed generation. For example, I think your favorable has 9,500 megawatts of PV versus, you know 13 or 14 hundred megawatts for distributed generation under a favorable scenario. I'm wondering if you cold clarify.

MR. PAIDIPATI: I think it has to do with the -- in the case of the central station PV, we're comparing it directly to the combustion turbine plant. But as I've discussed, for the customer-sited PV, we used a slightly different methodology of using a market penetration -- or a payback acceptance curve, so some of those things could be accounted for in there. I think that's probably the simplest explanation.

MS. ROSE: And do you include for the PV adoption the value of avoiding future escalation in retail rates?

MR. PAIDIPATI: Yes, yes, yes, yes. So in the customer-sited case, we have the three scenarios where

the electricity -- the customers' electric bills do increase per the natural gas prices we discussed in the three scenarios. That's correct.

MS. ROSE: Okay. And then just one last question. You note that -- you have assumptions in there about the availability of state rebates. How much does that affect the assumptions about PV adoption?

MR. PAIDIPATI: We found it wasn't very large later on because there's a spending cap on the state rebate right now of -- I believe it's in the neighborhood of 5 million-ish dollars per year. I know it's highly flexible and I think going up. But looking at that relative to the overall demand for PV, if those caps held, it did not make a huge difference, I would say. But in the earliers, it does, because when there's lower demand, it does make a very large difference, because it's -- I believe it's $4 a watt DC rebate.

MS. ROSE: It's very, very limited.

MR. PAIDIPATI: Yes, correct.

MS. ROSE: Okay. Thank you.

MS. MILLER: Mr. McGlothlin.

MR. McGLOTHLIN: My name is Joe McGlothlin. I'm with the Office of Public Counsel. Good morning to the three of you.

Your first question is a toss-up. Back to

business. My first question does call for a bit of a preface, and it will be short. And I'm sure the three of you have been following the development of the rule closely throughout each stage, and you'll recall that the first step was a straw man proposal, the main body of which made no distinction between one technology or the other, but provided some options. One option was called a multiplier effect, and the other option was called a set-aside or carve-out.

And we've had several workshops, and during the give-and-take dialogue among stakeholders and staff, there is a dispute over whether the ultimate rule should provide -- should contain provisions that favor certain technologies in the allocation of the money available for renewable energy credits on the one hand, or whether instead there should be no such distinction, and there should be one pot of money for which all of the technologies vie to be the most cost-effective.

And with that bit of background, I've read your document, and I heard you say this morning that when you consider the scenarios, no credits, 1 percent annual revenues, 2 percent annual revenues, up to 5 percent, in each such scenario you assumed that the money available for renewable energy credits would be allocated 75 percent to what's called Class 1, solar and

wind, and 25 percent to the other technologies. And if I understand you correctly, there is no scenario in the draft report to this point that examines the impact of the alternative case, which would be a percentage of annual revenues with no such allocation, with one pot of dollars. Am I correct in that?

MR. PAIDIPATI: That is correct. We did not look at that scenario.

MR. McGLOTHLIN: Now, if you'll turn to one of the slides in your executive summary -- I think it's page 7. No, I'm sorry. It's the one that reports the conclusions. And the conclusion states that the impact on RECs -- of RECs on the Class 2 technology was small, given the 25 percent allocation.

If you were to assume that no such allocation was made, do you think the conclusion would differ with respect to the Class 2 technologies?

MR. PAIDIPATI: That's a tough question to answer without looking at the analysis. It's hard to say. I don't think we can professionally answer that question without digging into it a little bit.

MR. McGLOTHLIN: Okay. Look at page 22 of the executive summary, which shows the scenarios, all of which include this 25-75 breakdown or allocation, and depicts graphically the potential for renewable energy

for each scenario. Again, if you were to assume that there's no allocation made to 25-75, do you think the graph would look different?

MR. PAIDIPATI: Again, that's hard to answer without actually running that scenario.

MR. McGLOTHLIN: Okay. Now, I want to refer you to a page that's not within the executive summary. It's within the full study, if you have that available. It's page 210.

MR. PAIDIPATI: Oh, boy.

MR. McGLOTHLIN: And the caption is "Class 1 REC selling price by year."

MR. PAIDIPATI: Okay. Bear with me here when I go to that page. We had it loaded up here. It will take a second. It's a long report.

Oh, thank you. You just saved us five minutes. Next page. That's okay.

Okay. Yes, correct. Yep.

MR. McGLOTHLIN: There you go. And I'll probably need some help from you in explaining what this depicts, but as I understand it -- and first of all, this is the renewable energy credit selling price for the solar and wind --

MR. PAIDIPATI: Correct.

MR. McGLOTHLIN: -- technologies in Class 1 --

MR. PAIDIPATI: Uh-huh.

MR. McGLOTHLIN: -- by year. And in the early years, you see values ranging from 145 to $180 per megawatt-hour. Now, is that in part a function of the availability of 75 percent annual requirement?

MR. PAIDIPATI: Correct, yes.

MR. McGLOTHLIN: So the allocation of 75 percent of the annual requirement pot of money would under this scenario be steered to pay the solar technologies up to $180 per megawatt-hour for the energy that they sell?

MR. PAIDIPATI: That's correct. The REC selling price would be $180 a megawatt-hour.

MR. McGLOTHLIN: And that, of course, we understand is above and in addition to any price for the energy itself. This is just for the renewable credit.

MR. PAIDIPATI: Say the question again. It's above the --

MR. McGLOTHLIN: If this is the REC selling price, I assume that is for the renewable attributes only and not for the energy.

MR. PAIDIPATI: Yes, correct. That is just for the renewable attributes, yes, yes, yes.

MR. McGLOTHLIN: Now, if you'll turn to page 211, this is captioned the Class 2 REC selling price,

Class 2 being the technologies other than solar and wind. It shows under the assumptions here, depending on the scenario, selling prices ranging from 4 to $18 per megawatt-hour.

MR. PAIDIPATI: Correct.

MR. McGLOTHLIN: And is that a function of the fact that under your assumptions, only 25 percent of the available pot of money is spent for that purpose?

MR. PAIDIPATI: The staff draft rule had the specification of 75-25.

MR. McGLOTHLIN: Yes.

MR. PAIDIPATI: And also, this is a function of -- if you recall, there's already roughly 1.5 gigawatts of Class 2 renewables installed in the State of Florida, so those technologies -- we made the assumption that those technologies or those facilities would qualify for the RPS, again per the staff's draft rule. So those technologies would be eligible for the RECs, and that would in turn create a larger pool for the RECs in Class 2, so it would create an overall lower REC price.

MR. McGLOTHLIN: So the price per REC is in part a function of the larger universe of such projects?

MR. PAIDIPATI: Yes.

MR. McGLOTHLIN: But it's also a function of

the availability of only 25 percent of the pot of money; correct?

MR. PAIDIPATI: Correct, yes.

MR. McGLOTHLIN: So if there were no such allocation, would you expect the selling price for the Class 2 technologies to differ from what's shown here?

MR. PAIDIPATI: I believe it would increase, but to what degree, I can't answer that.

MR. McGLOTHLIN: You can't say how much, but there would be an increase, and it could be a material increase; would you agree with that?

MR. PAIDIPATI: I can't say, again, because then it would probably drive more adoption of the Class 2 RECs, so again, it might bring the REC price back down. It's a balance, and it's hard to say where that would go without actually looking at that scenario.

MR. McGLOTHLIN: You mentioned a moment ago that the draft rule contains a 75 and 25 allocation. Is it for that reason that you built that assumption into --

MR. PAIDIPATI: Correct, yes.

MR. McGLOTHLIN: But the draft rule also incorporates the renewable energy credits, does it not?

MR. PAIDIPATI: In what way?

MR. McGLOTHLIN: It provides for a market for

renewable energy credits as a provision of the draft rule, does it not?

MR. PAIDIPATI: The 75-25 is how the expenditures for those credits are --

MR. McGLOTHLIN: And the 75-25 is a subpart of the renewable energy credit mechanism that is part of the proposed rule.

MR. PAIDIPATI: Okay.

MR. McGLOTHLIN: But you also examined scenarios in which there are no RECs; correct?

MR. PAIDIPATI: Yes. Yes, that's correct.

MR. McGLOTHLIN: So in that instance, you departed from the draft rule?

MR. PAIDIPATI: That's correct.

MR. McGLOTHLIN: And the draft rule calls for the assumption of 2 percent of annual revenues.

MR. PAIDIPATI: Yes.

MR. McGLOTHLIN: But you also examined cases for 1 percent and 5 percent.

MR. PAIDIPATI: Correct, yes.

MR. McGLOTHLIN: So my question, I suppose, is that if you didn't feel that you were tied to those aspects of the exercise, why did you limit the scenarios to the 75-25 allocation?

MR. PAIDIPATI: We worked with the Florida

Public Service Commission staff to develop that scope. I mean, it's an interesting thing we could consider of going without that bound. I mean, we would have to discuss it with the PSC staff, but we could take that under consideration.

MR. McGLOTHLIN: This is a point to be followed by a question.

MR. PAIDIPATI: Okay.

MR. McGLOTHLIN: The point is, there are those of us among the stakeholders who would like to be able to compare and contrast the effect of a rule that has the 75-25, as in the proposed rule, on the one hand, and a rule that makes no distinction among technologies and says for the benefit of the ratepayers, chose the most cost-effective, on the other. And is it fair to say that in the document as it stands now, there's no quantification --

MR. PAIDIPATI: Correct.

MR. McGLOTHLIN: -- that would allow us to do that?

MR. PAIDIPATI: Yes. I think that's something we can take into consideration for the final report, yes.

MR. McGLOTHLIN: That's my question. Would it be doable if it were perceived to be worthwhile?

MR. PAIDIPATI: We'll have to see, given the time left to us, if we can fit that in. Obviously, that's a large undertaking, and budget is another concern.

MR. McGLOTHLIN: All right. Well, I know I've taken a little bit of time. I'll just ask -- I'm going to change subjects now and ask you to elaborate on something having to do with the Fisher-Pry substitution curves.

MR. PAIDIPATI: Yes.

MR. McGLOTHLIN: Now, it has been several years, but I was involved in a case that involved the application of the Fisher-Pry theory. And as I understand it, the proposition is that when a new technology enters the marketplace, after a relatively short period of time, their rate of penetration becomes constant, and when that constant rate of penetration can be measured, it's then possible to predict by projecting forward at that same constant rate the pace at which it will take over the marketplace. Is that correct?

MR. PAIDIPATI: You can also look at the characteristics of the technology in the market in which it exists and project the rate of application as well.

MR. McGLOTHLIN: Well, that's my question, because as I understand it, the rate of penetration

would be specific to the particular technology.

MR. PAIDIPATI: Yes, yes.

MR. McGLOTHLIN: By way of easy example, the rate of penetration of microwave ovens is one value.

MR. PAIDIPATI: Yes.

MR. McGLOTHLIN: The rate of penetration for car-mounted GPS devices could be very different from that.

MR. PAIDIPATI: Yes.

MR. McGLOTHLIN: And don't you need sufficient data for the individual technology to enable you to make that prediction with confidence?

MR. PAIDIPATI: We did. We used several different curves, depending on each technology's characteristics.

If you look at the world of Fisher-Pry, you can -- and I don't want to go into too much detail, but there's curves A, B, C, D, and E that have varying what's called saturation time, T to one-half, time to one-half, and those are a function of the given industry and market that that technology is playing in. And we looked at those things, and for each technology, we made a distinction of, given its past usage, which I discussed, the market that it's playing in, which curve we would most likely apply to that given technology.

MR. McGLOTHLIN: Well, that's helpful, because when I read hurriedly, of necessity, the description of groupings and families of curves, it suggested to me that you were using proxies rather than the data for the specific technologies being measured.

MR. PAIDIPATI: Oh, okay. No, no. I guess we needed to convey that better, but, no, we used different curves for each technology, yes, yes.

MR. McGLOTHLIN: Those are all the questions I have. Thank you.

MR. PAIDIPATI: Thank you.

MS. MILLER: Are there any more stakeholders who would like to ask questions?

Yes, Mr. Moyle.

MR. MOYLE: I don't want to cut in line. I'm Jon Moyle. I'm with the Anchors Smith Grimsley firm. I appreciate you all spending a lot of time on this report. It was a lot of work. I represent Wheelabrator Technologies, which is a waste-to-energy company. I just had a couple of questions.

One, people have made brief comments, and I think Mr. McGlothlin representing Public Counsel brought out an interesting report, which, as I understood, your charge was to do an analysis that would help inform not only this Commission, but ultimately the Legislature,

because they have to ratify a rule and provide sort of a state-of-the-art report to them. And I think his point about your limitation where you looked at everything assuming a 75 percent wind and solar and 25 percent other may skew the results.

And I guess my first question would be, a lot of times in the legislative arena, people are like, you know, just give me your broad sense. But am I correct in assuming that if you looked at that issue and said, "Rather than 75-25, let's do a 50 percent-50 percent split," so 50 percent of the moneys would go to wind and solar and 50 percent would go to what you're calling Class B, wouldn't that get you a higher number in terms of renewables?

MR. PAIDIPATI: It's hard to say without running the analysis. I think definitely Mr. McGlothlin's comment is noted, and we'll discuss that with the Commission staff.

MR. MOYLE: So you could do no split, and then maybe a 50-50 split? Because it seems like your whole report has that 25-75 split, which, you know, knowing some of the folks in the Legislature, they may say, "Look, we appreciate wind and solar, and we appreciate the Governor encouraging that, and wind and solar is a good thing, but what gives us our biggest bang for our

buck?" And I'm not sure there's anything that is in that report that would tell you that.

MR. PAIDIPATI: Yeah, that's definitely something we can look at, yeah.

MR. MOYLE: Okay. A couple of other questions. On your biomass chart on page 13, you used a 85 percent capacity factor for municipal solid waste, and I was wondering why you used that for all the biomass.

MR. KATOFSKY: We used that to represent a base load technology, so all the biomass technologies are essentially base load, so that would be the average annual capacity factor over the course of a year, taking into account any downtime or part load operation.

MR. MOYLE: Is that a reasonable capacity factor, in your view?

MR. KATOFSKY: I think it is, yes.

MR. MOYLE: On page 17, you had certain financial assumptions. And I think this may be my last question. You had this chart that talks about financial assumptions, depending on the technology's commercial status. Certain biomass products, as I understand it, like the bioenergy crops, they do have a cost associated with the input; correct?

MR. KATOFSKY: Correct.

MR. MOYLE: So to the extent that there's a fuel cost associated with biomass and there's not a fuel cost associated with things like wind and solar, wouldn't that argue for an increased risk on the part of an investor?

MR. PAIDIPATI: No, that's an interesting point that was brought up earlier today. I think that's something we need to take into consideration going forward.

MR. MOYLE: And if it did have an additional risk component, then I would assume that both the cost of debt and the cost of equity would go up.

MR. PAIDIPATI: That's correct. That's an interesting point that was brought up. Yes, I think that's something we're going to take into account.

MR. MOYLE: So you would agree with that?

MR. PAIDIPATI: Yes, yes.

MR. MOYLE: All right. I think that does it. Thanks again for all your hard work on this.

MR. PAIDIPATI: Thank you.

MS. MILLER: Thank you. And do we have other speakers?

MR. KARNAS: Thank you. I'm Jerry Karnas, Climate Project Director, Environmental Defense Fund. I was a member of the Climate Action Team, and I'm trying

to get a sense -- have you guys been able to pinpoint why your conclusions are so different from -- the energy supply and command section from the Climate Team's?

MR. PAIDIPATI: We have not compared those sections as of yet, if you could recommend us where to go.

MR. KARNAS: All right. I've tried to look at it a little bit. It seems to me that -- so on the natural gas pricing assumptions, am I correct that you guys, that the worst-case scenario that you put forth between now and 2020, that we've already been in that for the past couple of years?

MR. PAIDIPATI: We had been in 13 to 14 MMBtu range, yes.

MR. KARNAS: So if you did like a sensitivity analysis -- am I reading it right that they're projecting natural gas prices to basically be stable for 12 years?

MR. PAIDIPATI: It depends. We used a -- we didn't use the increasing or decreasing. We bracketed the price over that time frame.

MR. KARNAS: Right. I'm just trying to find out why what we've been in for the past couple of years would be considered the worst-case scenario. Do you know what I'm saying? It would seem to me that 11 to

$14 would be kind of a mid range case, and if you did sensitivities of, you know, 3 percent, 5 percent, 7 percent, you're getting upwards of --

MR. STANBERRY: Part of the reason for that is the steep drop that that has been experienced over the last three months or so in natural gas prices, so that $13 is a much higher level now than it would have been if we were doing the study back maybe six months ago. And we actually have a natural gas pricing unit within Navigant that tracks these prices, and we built our assumption in consultation with some of their forecasts as well.

MR. KARNAS: But that's a key assumption for the support, you would agree, the natural gas prices? A lot flows from that?

MR. PAIDIPATI: I would agree, yes.

MR. KARNAS: Right. And so if we did start seeing volatility, that would change a lot of the other --

MR. PAIDIPATI: Obviously, yes, the price of natural gas we have as our number one key driver.

MR. KARNAS: And there are still some people that are looking at $200-a-barrel oil by 2030. You know, there are still a lot of analysts that are still talking about that. So if natural gas is one-sixth the

cost of a barrel of oil, if it's $100 a barrel, it's going to be $20. You know, if it's $200 -- right?

MR. STANBERRY: Actually, the two do not necessarily track each other. They have over the last couple of months for sure, but they don't necessarily track each other over time. And what has happened in the U.S., there has been a tremendous increase in the supply of natural gas that has helped drop the price.

Do you know what the price is sitting at now? Six? Yes, it's down to six now, or in that range.

MR. KARNAS: I agree. So if the global -- you know, globally natural gas is trading at something higher, we may have a little cushion there, but it's still going to be --

MR. PAIDIPATI: I guess to get to the heart of the question, if you have a set of assumptions you would like us to look at, you can submit it to the PSC staff, and we can take a look at that. And also, if you could, provide the background to that set of assumptions.

MR. KARNAS: I will do that. Thank you.

Just building on Public Counsel's comments as well, did you look at other scenarios in terms of the construction of a REC market? For instance, did you look at how the pricing of the assumptions would work if the REC was not a tradeable REC, but a long-term kind of

contract REC at a fixed price?

MR. PAIDIPATI: No, no. We looked at a flexible market.

MR. KARNAS: Do you have an opinion about what that would do to the price?

MR. PAIDIPATI: No. I've never actually modeled that before, so I don't know what that would do. I understand the concept of locking in a long-term price as used in other parts of the country. That's an interesting proposal.

MR. KARNAS: And so I just have a question about the RECs. It starts at 189; right?

MR. PAIDIPATI: Uh-huh.

MR. KARNAS: And then generally the levelized cost I see from what the Action Team came up with of like 134. You guys came up with what, 142 or something?

MR. PAIDIPATI: Yes.

MR. KARNAS: And so why would somebody pay $180 --

MR. PAIDIPATI: Up front?

MR. KARNAS: Yes, for the REC, when really the value is $134?

MR. PAIDIPATI: Because we reported the LCOE with the REC included, so that actual value of the energy is the LCOE, in those particular cases, plus the

value of the REC. So we have two sets of tables in the report, with and without RECs for both scenarios, so I would refer you back to those. It's roughly page 205. I would refer you back to that to look at what the value of the energy is.

MR. KARNAS: Okay. Thanks. I appreciate it. Thank you.

MS. MILLER: Thank you. Mr. Reedy.

CHAIRMAN CARTER: Cindy, hang on a second.

Okay. Go ahead. I just wanted to say in a minute -- let me just say to my colleagues how much I appreciate us deferring to allow for as much input as possible on that, but we will get back to the bench. I just wanted to kind of give you a heads-up.

Ms. Miller.

MS. MILLER: Mr. Reedy.

MR. REEDY: Thank you. Bob Reedy with the Florida Solar Energy Center.

We were in a lot of discussion about the cost data and the feasibility data, and certainly it's a massive amount of work. It probably relieved us a little bit of trying to produce some of this. However, as you can imagine, as I come back and review the results, I do have some questions.

A particular question I do have regards the

large scale of customer-sited PV installations. We had discussion about how difficult it was to establish what that cost is even today, because those large scale projects are just getting under way. But one that really troubles me is that there is a significant project in California that Southern California Edison has done. I'm sure you're familiar with it.

MR. PAIDIPATI: Yep, yep.

MR. REEDY: And they are -- I've had direct conversation with SCE about it, and they have, they're very happy, 350 a watt for 250 megawatts. And that's the answer right there, is that it's 250 megawatts and not 500 kW.

And I -- it's somewhat of a rhetorical question, but could you address maybe how we could expect to see not the prices -- you have the prices in 2015 down in that range, but for 2008, which is today --

MR. PAIDIPATI: Well, the SoCal Edison program I believe is staggered over a five-year period. They're not installing -- I believe it's 50 megawatts a year they're installing.

MR. REEDY: Right.

MR. PAIDIPATI: So that is taking -- and the contracts they have with the module suppliers take that time into account. So I don't believe -- they're not

installing it all in 2008. And then probably the answer is, they are installing -- it is a bulk buy.

I don't know. We tried to capture the average selling -- the average module -- the average system cost in the State of Florida over a time period. I would say that the SoCal Edison represents the lower bound, but then there's also an upper bound in more fragmented markets where the value chain is not as streamlined as it is in the Southern California Edison territory at this time. So I think we got to the midpoint of that over this time period.

MR. KARNAS: So perhaps then it would be -- it's very reasonable to expect a serious project in Florida to be down to those types of numbers?

MR. PAIDIPATI: There would definitely -- I think it would be lower than what we reported, but I can't say how low it would go. I'm not sure in terms of all the details of the SoCal Edison project. Obviously, like I said, we were reporting an average, a lot of that driven by the stakeholder comments of what to use. But there is definitely a possibility for lower or higher for any of these technologies.

MR. REEDY: I recognize that there's manufacturing in California as well, and that affects some of the purchase price, but there's a lot of

interest in manufacturing in Florida, particularly as this RPS goes forward, and there is a direct response to --

MR. PAIDIPATI: No, I think for any of these technologies, there's a possibility for higher or lower costs. We tried to portray the middle of that range.

MR. REEDY: Thank you.

MS. MILLER: Mr. Chairman, I know it's noon, and would you like to go back to Ms. Clark and have some more and then to Commissioners?

Oh, I'm sorry, Mr. Cavros.

MR. CAVROS: George Cavros on behalf of Southern Alliance for Clean Energy. I just had a few quick questions.

On slide number 22, you show renewables at a 6 percent level, and I was wondering where that data came from. I thought maybe we were closer more to the 3.6 percent level.

MR. PAIDIPATI: Some of that is what Ryan mentioned, that the original data collection did not include the pulp and paper industry inputs. And then also, we're showing -- this number here is at the end of 2009, so this takes into account any installations during the year 2009, so it might raise that number up. So this is definitely something that's still, I would

say, a work in progress, and that will be resolved by the final report.

MR. CAVROS: Okay. And your analysis, or your scenarios you say you ran without RECs. Does that mean without an RPS, or does that mean with an RPS but without RECs?

MR. PAIDIPATI: We didn't distinguish between the two, so, yes, it was without the economic benefits of RECs that would be driven by the presence of an RPS.

MR. CAVROS: And on page 15 or slide 15 -- and you've alluded to this before, but it looks like fossil fuel prices has the highest relative impact on renewable energy adoption, but it also has the highest relative uncertainly as well; is that correct?

MR. PAIDIPATI: Yes, that's correct, yep, I think as evidenced by what has happened in the last six months.

MR. CAVROS: Sure.

MR. STANBERRY: It's uncertainty about what price those fossil fuels would take.

MR. CAVROS: And in your modeling, were you able to model for price sensitivities? And I think you actually discussed this in your introduction, where you could model for certain fossil fuels increasing at certain levels at different times to come up with

different conclusions?

MR. PAIDIPATI: I think how I'm interpreting that, if the fossil fuel prices changed relative to what we've simulated it as, yes, then the results would change, yes.

MR. CAVROS: Okay. Thanks. And did you model for transmission and distribution savings for --

MR. PAIDIPATI: No, no. As to the earlier comments, we did not look at the T&D savings or -- there's many phrases you can use, the external benefits of certain technologies. We did not draw that into the analysis.

MR. CAVROS: Sure. I assume there are probably a host of external benefits that either maybe haven't been easily quantified, you know, in past studies, or can't be. Were you able to model, you know, for water use, for instance?

MR. PAIDIPATI: In what way?

MR. CAVROS: In what way? You know, certain distributed generation technologies, solar, for instance, don't use water. Water is a commodity in Florida.

MR. PAIDIPATI: No, we didn't directly --

MR. CAVROS: Is there a way to model for that?

MR. PAIDIPATI: We didn't assume a value, but

that would be included in the O&M costs of whatever traditional technology it was competing against, so impulsively it's in there, yes.

MR. CAVROS: Okay. And leading up to the RPS rule, the Legislature and the legislative intent had strong economic intent language. In other words, they wanted to really promote investment in the State of Florida through an RPS. Did you model for job creation?

MR. PAIDIPATI: No, but we've actually done a lot of work in that area, and afterwards I can refer you to a host of studies we've done in that area. But we did not account for that in this study.

MR. CAVROS: All right. Thank you.

MR. PAIDIPATI: Uh-huh.

CHAIRMAN CARTER: Before we come back to the bench, let me just see if there's -- I know Ms. Clark had a couple more questions, but let me just see if there's anyone else that didn't get an opportunity to ask questions this morning, because I do want to give ample opportunity, but I do want to allow my colleagues to ask their questions.

Come on down, sir. Anyone else? Because we do want to -- to my colleagues, I appreciate your patience on this.

Good morning, or good afternoon.

MR. JONES: Thank you, Mr. Chairman. My name is Dell Jones with Regenesis Power, and I just have just a quick couple of questions regarding the scope and the tasks.

Within the tasks, there was to identify the renewable energy resources for Florida. And as you guys know, it honed in on less than 2 megawatts for solar thermal. And we've had this discussion before, but I just want to kind of identify the practicality of solar water heating as a technology. And I know it was not within the scope of your tasks to do that.

My question to you would be, with 20/20 hindsight, knowing that it wasn't within your scope, you weren't budgeted for it, do you think it would be considered an oversight to not have evaluated utility-deployed solar water heating programs into this?

MR. PAIDIPATI: I think that's going to be captured by the parallel study, the impacts of that, so I can't say whether or not it was an oversight or not.

MR. JONES: Just sort of looking at some of the technical potential, if I look at the difference between residential rooftop photovoltaic systems, and if within the study residential solar water heating programs deployed through utility programs, you know, I guess my comment would be probably the order of

magnitude would be equal to what the residential --

MR. PAIDIPATI: Yes, the technical potential would be much higher.

MR. JONES: So the point, it's probably at least that, probably more.

MR. PAIDIPATI: It's hard to say.

MR. JONES: You know, given that it takes about one-seventh of the area of a roof and puts out the same amount of net energy or environmental result back to the consumer.

MR. PAIDIPATI: It's hard to say without modeling. I know I've never actually done solar water heating market penetration. But obviously, the technical potential would be much higher.

MR. JONES: Yes. And I guess what I'm really trying to get an understanding or have it understood that it wasn't really so much of a fault of yours of not including it. It was within the scope. You weren't budgeted for it or --

MR. PAIDIPATI: No, no, no. It's specifically -- in our scope of work, we specifically did not -- we were not tasked to look at 2 megawatts. They specifically asked us not to look at 2 megawatts and below, because that's looked at in the study in support of the FEECA work.

MR. JONES: And again, despite the fact that it represents a significant impact to the renewable energy potential for Florida.

MR. PAIDIPATI: Yes. I would voice that concern with the staff.

MR. JONES: I know. It's sort of -- the cow is out of the barn now, so to speak.

But I guess just to the Commission, I just wanted to make some points. Our company is in contract with one fairly small utility, Lakeland, Florida, and our independent engineer's report supported by our funding institution, Citibank, concludes that we have a potential generation capability just within Lakeland alone of 80 megawatts. So again, that just represents again a significant oversight of the potential for solar water heating deployed through utility programs, not projects, but programs for ongoing years, you know, a significant technical potential. And that's all the comments I wanted to make.

CHAIRMAN CARTER: Thank you for your comments.

Ms. Clark, we're back to -- oh, Ms. Brownless, one itty-bitty one, and then we'll go to Ms. Clark.

MS. BROWNLESS: Very small.

CHAIRMAN CARTER: You're recognized.

MS. BROWNLESS: Thank you. The only thing

that I would follow up with on Mr. Jones's comments is that residential solar hot water is included in the technology within the proposed rule which could generate RECs. And so the fact that you have a significant impact that could have been made by the residential solar hot water, but is not included in the study, and therefore might have the potential, and we believe would have the potential to lower the price for the RECs, is a serious flaw.

And that's all I would like to say. Thank you.

CHAIRMAN CARTER: Thank you. Ms. Clark.

MS. CLARK: Thank you, Mr. Chairman. I'll try to be quick.

I wanted to go back to some of your information on the biomass potential. And it's my understanding that a lot of it comes from energy crops and natural and induced forest growth. I also understand that that same feedstock or the land used to produce it could also be used for cellulosic ethanol production.

So my question is, how do you take it -- and the price for that is probably more in that market, so how have you taken that into account when you estimate the potential for renewable from that resource?

MR. KATOFSKY: We assumed that there would be by 2020 demand for about 5 million dry tons of biomass to go towards -- and I wouldn't even say cellulosic ethanol. Let's just call it second generation biofuels, because it's not all going to be necessarily ethanol either. So we actually took that amount out of the technical potential between now and -- growing from essentially zero today to that 5 million dry tons by 2020. But in terms of the pricing, I can't say what -- you know, our pricing assumptions were stated earlier, but we did factor in competing demand for that feedstock.

I think it's worth noting that those facilities will produce a certain amount of electricity as well, which also is not factored in here, but that's something to bear in mind.

MR. PAIDIPATI: If I could just follow up on that. That 5 million dry tons comes from the Governor's Action Team on Energy and Climate Change. They had listed that as a target for 2020, the 5 million dry tons, so that's where we took that from.

MS. CLARK: You also include biomass and co-firing coal units. How are you accounting for the effect on the fly ash?

MR. KATOFSKY: We did not -- I think that's

something that would need to be fleshed out a little bit further to see how realizable that potential would be in terms of the fly ash specifications. We did not factor that into the analysis.

MS. CLARK: Okay.

MR. KATOFSKY: I'm not sure which plants do and don't sell the fly ash. We didn't get to that level of detail.

MS. CLARK: This is another question on the interplay of these resources. Where in the process will the overlaps between municipal solid waste and landfill gas be addressed? It's similar to your recycling scenario. Where you use it for one, it's not going to be available to landfill and produce the gas, and where have you taken into account that interplay.

MR. KATOFSKY: I'll have to double-check, but I believe that the landfill gas potential is based upon current landfill situations, and going forward, I think those are expected to remain steady. But I -- I'm sorry. Expected to remain steady. That's one I know we're still researching. We got your question on the original round.

MS. CLARK: But would you agree it may not remain steady if you're landfilling this -- if you're using what you would use to landfill for municipal solid

waste if you compete?

MR. KATOFSKY: It's possible that it could decrease some in the future if you had a very high degree of waste-to-energy penetration in the future.

MS. CLARK: Okay. Did you take into account that additional generation may be needed to compensate for when solar and wind technologies are not available at peak?

MR. PAIDIPATI: No, we did not take into account that.

MS. CLARK: Okay. I noticed your study goes to 2020 only, and I believe the staff's recommendation is to reach 20 percent by 2041. Will you be doing the escalation to make the periods match?

MR. PAIDIPATI: No. We were not funded to go out to 2041. I could do a quick commercial for Navigant Consulting, but I won't try that.

MS. CLARK: And it's also our understanding you're not considering what additional transmission and grid investment which may be necessary to support --

MR. PAIDIPATI: We did not do that for both the traditional technologies and the renewable technologies. I mean, doing a detailed transmission study was outside of our scope of work. The only body of data we had was the ten-year site plan that has -- I

believe it's approximately 620 miles of transmission to support the traditional technologies in the ten-year site plan. We didn't think it was fair to include it for one technology and not the other, so we looked at it on a plant-by-plant basis.

MS. CLARK: And my last question is about your electric consumption growth rates. And I understand staff provided you with that, and you don't know if it has taken into account recent economic conditions and --

MR. PAIDIPATI: I would refer that back to the staff.

MR. BALLINGER: Tom Ballinger with staff. The growth rates that we provided Navigant were the same ones we got from the utilities with the data request to give us your updated sales forecast. So if that took into account recent economic conditions, that's what we gave them.

MS. CLARK: So you used the same data request.

I think that's all we have, Mr. Chairman. Thank you for allowing me more time.

CHAIRMAN CARTER: Thank you.

Commissioner Skop, you're recognized.

COMMISSIONER SKOP: Thank you, Mr. Chairman. I'll make this brief, because I know the lunch hour is hear.

But I just wanted to -- I had one question for Navigant, and this is, I believe, on page 23 of the report, or slide 23. At least from what I've heard, it seems that Navigant is indicating that RPS is inextricably intertwined with a REC market, and I was just wondering if Navigant could provide some explanation on that.

MR. PAIDIPATI: We assumed -- we made that assumption linking the two. We didn't look at what would happen if there was an RPS goal but no RECs associated with that. I think that's another variable. That's something that we didn't look at.

COMMISSIONER SKOP: Okay. Thank you. And just as a general comment -- and in the interest of time, I'm not going to go into the details, but I tend to agree with most of the comments advanced by Ms. Clark with the extent of the discussion of offshore wind potential versus onshore, and I was wondering if -- certainly her comments are correct that there has never been an offshore project sited or constructed in the United States yet, and I just wanted Navigant to elaborate a little bit more on that with respect to --

MR. PAIDIPATI: Sure.

COMMISSIONER SKOP: -- the greater potential, but also the increased costs to the extent that

certainly doing it onshore would be a cheaper alternative.

MR. STANBERRY: With respect to offshore development, there has been some significant development in Europe. And actually, just over the past four months or so, there's been some PPAs signed along the eastern seaboard for offshore wind projects.

So while there is not an installation under way currently or construction underway, the feeling in the development community and the regulatory community and from folks that we've talked to in the industry is that the technology is going to be available, certainly within the 2020 time frame, and is actually close to being available. It essentially needs conversion to the U.S. market.

And the MMS, the Minerals Management Service, when they come out with their final rulemaking on permitting for offshore systems, which is slated to come out by the end of this year, may drift into the early part of next near, it will remove one of the primary barriers to offshore development.

COMMISSIONER SKOP: So to those points, Navigant would concur with the assertion that offshore wind on an installed capacity basis is significantly more expensive than its equivalent onshore --

MR. STANBERRY: Certainly, yes.

COMMISSIONER SKOP: And Navigant would also concur that the offshore O&M costs would be significantly higher than onshore?

MR. STANBERRY: That's correct, yes.

COMMISSIONER SKOP: And I guess with respect to the MMS and the permitting side, I've been following that closely. I used to work in the wind industry. You know, the Cape Cod projects, the Delaware projects, none of those have come to fruition, but at least, you know, since I've been in law school, probably over five years, they've been talked about substantially and significantly opposed.

And I'm wondering -- what I sensed from the Navigant study is that certainly the potential offshore in terms of a wind resource is greater than within the state. I don't dispute that. But I'm looking at the costs, and I'm also looking at the fact that, you know, if we're incurring delays in getting it done in terra firma in the State of Florida right now, I mean, how are we humanly going to possibly get it done offshore in a timely manner to meet the Governor's stated goal of 20 percent by 2020?

MR. STANBERRY: There certainly is a longer time frame associated with offshore, but not just in

getting -- you know, being ready to do installations, given that you have to wait for MMS to come out with their ruling. There's also a longer time frame for development, which we took into account in our modeling for when adoption could occur.

COMMISSIONER SKOP: And would Navigant, based on its knowledge -- we have some feedback.

CHAIRMAN CARTER: Everybody hold on. We have to do some technical voo-doo.

(Off the record briefly.)

COMMISSIONER SKOP: Thank you, Mr. Chairman.

Just following up on that, if by virtue of the fact -- and looking at the comparative times for installing the capacity for wind, would Navigant agree that if a wand could be waved and we could get the permitting issues associated with installing a wind farm in South Florida or a demonstration project in South Florida, if we could remove those barriers, would Navigant concur that that demonstration project of 13 megawatts, or whatever it might be, could be up and running within, say, a year as opposed to the significant time frame of offshore, comparative offshore installation?

MR. STANBERRY: Yes. The general time frame that we use for onshore is about two years, but that

includes a permitting time frame and wind study time frame. And if you're referring to the St. Lucie project, that's been studied for wind speed, then you're already cutting that down somewhat. So certainly you could get an onshore project up faster than an offshore project.

COMMISSIONER SKOP: And then just a clarification, a point of clarification on the time frame for offshore. I believe in the study I saw a time span of five years instead of two. Would that be more accurate?

MR. STANBERRY: Yes, five years, sorry. I mean the onshore at two years. Yes, five years for offshore.

COMMISSIONER SKOP: All right. Thank you for that clarification.

Just one final observation. With respect to the biomass and the net capacity factor, I guess a concern came up from Wheelabrator with respect to the value that was chosen. Can Navigant just briefly comment on how that value was arrived at or why it's not a little bit higher?

MR. KATOFSKY: I think it can be higher in any given year. 85 percent is effectively our -- what's called our standard assumption for biomass plants.

There is some scheduled downtime over the course of the year. There are periods of time where it may not be operating at full power for one reason or another. It's just a -- call it is a typical assumption for a base load power plant. In any one year, it may be higher or it may be lower.

COMMISSIONER SKOP: Thank you.

CHAIRMAN CARTER: Thank you. First of all, I know we ran over time, but it was our desire to hear from all the stakeholders. As you know, during this entire process, we've gone above and beyond to ensure that everyone gets an opportunity to be heard. We thank you for your input, and we are committed to having the best RPS rule in the country. We are committed to meeting our deadline with the Legislature, but we're also committed to making sure that all voices are heard. So I apologize to my colleagues for going over time, but I did want to hear from everyone that had come to give us input and feedback, because this is our last workshop, and we'll be going from there.

So let me do this. Commissioners, we kind of took the wind out of the sail for staff. I know they've got to get ready for their presentations this afternoon. Let me look at this one.

I had to get Bob Trapp to help me with my

sundial. Commissioners, we'll come back at 1:30. We're on recess.

(Recess from 12:23 to 1:52 p.m.)

CHAIRMAN CARTER: We are back on the record. And thank you to everyone that has participated with us this morning. And before we kick off this afternoon's session, Ms. Clark.

MS. CLARK: Mr. Chairman, I just wanted to indicate I spoke to you and also to the folks from Navigant about the questions. They indicated they could provide us answers to those questions. I understand that it might not be within the time to respond to them in their comments, but we appreciate their providing those answers, even if they are beyond that time frame. Thank you.

CHAIRMAN CARTER: Thank you so kindly.

This afternoon we move into -- I started to say Phase 2, but -- this morning we've been in like so many phases, I think we've done phased out. This afternoon we have some staff presentations. We'll begin with Tom Ballinger.

Mr. Ballinger, good afternoon. You're recognized.

MR. BALLINGER: Good afternoon, Commissioners. My name is Tom Ballinger of the staff. I've got

something completely different for you this afternoon. The purpose of my presentation is to provide you some additional information on the integrated resource planning process and how renewables can fit into that.

At the October 14th agenda, the Commissioners specifically asked for additional information on specific topics. Today I'll discuss two of those topics. First I'll give you a general overview of the IRP process and how this process may be impacted by the adoption of an RPS policy for promoting renewable generation.

It's important to understand this foundation, because an IRP is the foundation for making sure we have a balance between reliable and cost-effective power in the state. And based on comments at the previous workshops and the October 14th agenda conference, I will discuss a relative comparison of four potential RPS rollout strategies. This comparison will help clarify the relative magnitude and cost differences between various options, but care should be taken, not absolute costs of each option. It's more for comparative purposes. And I'll say that again.

Mr. Futrell's presentation later on will cover the rest of the topics that were discussed at the October 14th agenda conference.

First I'll give you a overview of the IRP process. Really, the IRP process is a balancing act. You have to balance cost and reliability. And it incorporates both conservation, which are demand-side alternatives such as attic insulation, appliance efficiencies, load management, and generation side, from utility generation to renewable generation to purchases from other utilities and IPPS. And the key is to try to balance reliable service at a least cost.

Now, this looks a little confusing, and it's really not. Your basic IRP process starts with a load forecast, and it's based on historic trends and demographics and weather patterns. Included in this load forecast is the impact of existing DSM, as you see here. You also look at -- for example, if a load management program was in place, utilities would look at that program plus any additional customers added on in doing its load forecast, because the program is in place.

We also, as you know, we're going to be starting a process for DSM goals. In this load forecasting process, typically utilities will include a kilowatt and kilowatt-hour savings accompanied with goals that have been established as part of their load forecast. That has already gone through a

cost-effectiveness screening, if you will, and that's why it's included in the load forecast as well, but not specific programs.

Also in the beginning phase, you look at existing supply resources. You look at them from changes in performance, their availability, their maintenance schedules. You also look at existing purchased power contracts and when their term ends and do you have to replace that power.

And these are all put together to determine what I call the reliability need, when do we need to add something to the system to keep the lights on. And once that's done, the utility considers several portfolios of resource options, both supply-side and demand-side, to determine which mix meets the least cost plan.

And the results of the IRP process, as you see on the right side there, comes in to the Commission in various forms. We have the ten-year site plan, we have DSM goals, a variety of processes. And it's kind of an iterative process. The ten-year site plan is the -- I'll call it the end result of a IRP process that the Commission sees, but then it's also influenced by decisions we do in docketed matters. For example, when the Commission denied the need for the Glades coal project for Florida Power & Light, that had to

completely revamp their IRP process, because that was no longer an option in their plan. So that decision fed back into the IRP loop, and we go around again. So they interact with each other. What the Commission does and what a utility is planning work together, and it's kind of a continuos loop that goes on.

I'll go through this in a little bit more detail in a few more slides. And really, that was complicated, but I tried to make it simple. To me, IRP is a three-legged stool. And if you're familiar with three-legged stools, you take one leg out or push it up, and it gets unbalanced real quick. It's kind of hard to balance on a three-legged stool. And the utilities should seek a balance between DSM and renewable generation, because both of those are socially desirable alternatives to utility generation. That's what the customers are saying to us out there and what the Legislature has also said to us.

I'll give you a little bit more detail on the load side of the IRP process. There are really two components that a utility must plan to serve, which is your peak demand -- that's megawatts, and that determines the timing and size of a new unit or new resource. It may be a demand-side resource. And the other component is net energy for load. That's the

energy over a period of time, and that will determine more the type of the unit.

You'll see from this slide, and it will help explain the difference in types. You've got two different load shapes here that we typically see in Florida.

The blue line is more of a winter peak that we see in Florida. And you see typically we'll have two peaks, one first thing in the morning when people get up and they say, "Oh, my gosh, it's cold." I'll turn on the heat, I turn on the shower, I get up there, and the demand will spike up. And then it tapers off during the day, and it jumps up again at night when they come home and start cooking dinner and taking showers again.

The summer load is completely different, as you can see in the more pink line. It slowly rises through the morning as we get up, and then our air conditioners kick on, and they run basically all day long. From noon till about six or eight o'clock at night, it's continuously growing. This load shape can change dramatically if a thunderstorm comes through. That can knock 2- or 300 megawatts off the load in an instant.

So utilities have a challenge here that you've got two different load shapes you have to serve with one

system. So you have to not only meet both of these types of load shapes, but you only have one system to work with, so you have to look at different needs that you may need.

Now, here's a couple areas of load that a utility really doesn't have any control over. I know we've had a slowing economy and slowing growth in Florida, but people are still coming to the Sunshine State. And utilities, because of their obligation to serve, must serve every customer that comes to their service territory. Back in the late '80s, early '90s when the economy was thriving, the average house size increased about 30 percent. Those houses are not on wheels. They're still here. People are still occupying them, or even if they're vacant now, when the economy rebounds, they'll be refilled. That's energy that a utility is going to have to serve for 30 or 40 years that will be there. It's an infrastructure that's in place.

The good news is, there is some part that the utility can influence. They do have DSM, and if they can reduce the kilowatt and kilowatt-hours that customers use, they require less resources to build to serve that load.

And the way they do that is through FEECA.

FEECA requires the Commission to adopt goals that do these four things, conserve expensive resources, reduce and control the growth rates of electricity, reduce the growth rate of weather-sensitive peak demand. And this fourth goal was added this last legislative session, to encourage the development of demand-side renewable energy systems, such as rooftop PVs and solar water heaters. And FEECA authorizes the PSC and requires the utilities to develop plans to cost-effectively meet these goals. And we're in the process now of starting new goals. And as you've heard before, I think in 2009 we're going to have hearings and reset goals again to take this into account.

As I mentioned earlier, each resource has a different performance characteristic, and we have to meet those two different load shapes, so we're trying to figure out which one works best. So we determine our reliability need. We find out that in the year 2015 or whatever, we need some additional resources. I don't know whether they're demand-side or supply-side yet, so I've got to look at it. But each of my resources has a total cost of capital, O&M and fuel on the side of generation. It may not be fuel for demand-side.

And utilities typically look at a mix of resources that minimize their costs and still meet the

reliability criteria, and that mix is demand-side resources, it's purchased power, both from utility, non-utility, and renewable generators, and on utility generation. And it's during this part where units have different characteristics. For example, a nuclear unit can run 24 hours a day, seven days a week for a year, year and a half at a time, and never shut down, where a load management program might be very good at taking that peak off, that winter peak in the morning, but if you do it too long and interrupt people too often, the program will sour, and people will leave the system, and you've lost that benefit.

So all these resources have different characteristics and different costs that have to be balanced together into one portfolio. And it's during this economic analysis that the balance between reliability and cost first comes into play.

For considerations that are hard to quantify, I like to call these strategic benefits. Some of them are fuel diversity, which is really within the PSC's domain, because we do look at a balanced fuel supply. We try to look at the volatility of fuel and minimize impact to ratepayers.

Quite frankly, some of the strategic considerations may come at a premium. For example, you

might pay a little bit more for a solid fuel plant, be it coal or nuclear, to achieve some fuel diversity in your system to lower volatility of fuel price. It's a lot like hedging. So it may not be truly a least cost, but it is from the standpoint of looking at strategic considerations.

Some other strategic considerations that utilities look at that may not be in the PSC's jurisdiction are, say, economic development and environmental impacts, yet the utility takes that into account in its IRP analysis. It looks at permitting, availability of plants or resources. It looks at the economic development in an area, will it be receptive, you know, to that community, those types of things.

The way we typically look at it to try to quantify these strategic considerations is look at sensitivity studies. For example, fuel diversity, you'll look at is a particular plan sensitive to price fluctuations of one type of fuel, say, natural gas. If a plan can sustain increases and decreases in natural gas and still tells you, yes, this is the right resource to pick, that's a pretty robust plan, and you get the fuel diversity benefit. You've secured some risk. It's kind of an insurance policy. If you see that it is sensitive to fuel, you may want to look a little further

and do something different.

And here's what we're really talking about now, is where does RPS fit into this. And I kind of drew this because I'm not really sure where it's going to go when we pick an RPS. If you pick a mandate, you have taken out the economic part, if you will, of an IRP process. They're not competing head to head, and that may be okay. Like I said earlier, renewables are a socially desirable alternative to utility generation. There may be an incentive or a requirement to do a premium to promote these technologies for other reasons, other strategic benefits.

The problem comes in, though, if you've done that, where do I put it in the process. If I put it in before I do my economic analysis, I may be short changing DSM, which might be even more cost-effective and have even a better either environmental profile or economic development profile than anything, because I've done it in isolation. If I put the RPS after my least cost resourcing analysis, then I'm having ratepayers paying for something that may not be the least cost, and am I really getting the benefit.

So I'm not sure where we need to factor in RPS, but that's the fact. If we go to a mandate, that's the impacts it could have on an integrated system. And

I guess the real key on this is not to look at RPS in a vacuum, to try to look at it that it does impact other things.

And now I'm going to move on to some of the strategies that we discussed. Before I continue, I need to point out, and it came up earlier in conversation, that staff did ask for a data request from the IOUs for their updated sales forecasts, because we had heard too that sales were dropping and all that. In previous workshops, we were relying on the ten-year site plan data.

CHAIRMAN CARTER: Will you yield for a moment?

MR. BALLINGER: Sure.

CHAIRMAN CARTER: Commissioner Skop.

COMMISSIONER SKOP: Thank you, Mr. Chairman.

Just a quick question to Mr. Ballinger with respect to the integrated resource planning presentation portion of the presentation that you're giving. Wouldn't there be, or do I correctly understand it that there seems to be -- is staff advocating that there's an inherent tension between integrated resource planning capacity requirements and the installed capacity necessary or that would be necessary to meet an aggressive RPS implementation target?

MR. BALLINGER: If I understand your question,

later on in my rollout, I'll talk about how pricing out renewables, we need to take into account the need for capacity or the lack thereof. If we've already secured a lot of our resources, that changes the energy price paid to renewables, and hence the premium you would have to pay to get there.

COMMISSIONER SKOP: Okay. I think previously staff had indicated in a prior workshop that apparently there was like 1,600 megawatts or something necessary that might be freed up for renewables. But certainly that installed capacity in that amount wouldn't be sufficient to generate the RPS targets that we're looking at; is that correct?

MR. BALLINGER: You're correct. I think -- okay. Now I understand. If we looked at it just from a reliability standpoint, how many megawatts we would need in addition. The number would be small for renewables to get to any significant figure.

COMMISSIONER SKOP: Okay. Thank you.

MR. BALLINGER: Back to the strategies. With the data request, we did get revised sales forecasts from the utilities to recalculate the gigawatt-hours that would be associated with a 20 percent RPS in a certain year, things of this nature.

What came out of this was interesting. As

we've all been talking about, percentages of retail sales, which is what's mandated, if you will, in the statute, to look at an RPS as a percent of retail sales, but just from the sheer fact of changing the load forecasts because sales have declined, a number out in 2020 reduced by 5,500 gigawatt-hours. If you kept the same percentage in 2020 from the ten-year site plan forecast to the revised forecast, the gigawatt-hours dropped 5,500.

That told me that maybe we want to consider looking at RPS in terms of a fixed gigawatt-hour number, not a percent of retail sales, because it can be affected by load forecasts. They change. If you do more DSM, it would be more easy to meet your RPS goal if it's a percentage, because the gigawatt-hour is falling out. So it's something that came about, and because of this, we have to consider as we're going through this how best to do that.

What we also found out is, with the reduced sales and committed capacity, it looks like the next ten-year site plans will show very little, if any, additional capacity needs over the next ten years. That's telling me, and we've said this before in earlier workshops, it looks like we're pretty committed from where we're at reducing load forecasts. It looks like

utilities have secured up resources to meet our reliability needs. What that means to me is the most likely result is that the payment to renewables for any energy produced would be energy only, the as-available energy only. And I'll take that into account in my later slides and show you through the economics.

Okay. At the October 14th agenda, the Commission asked for options, an aggressive RPS, a less aggressive RPS, and things of this nature. So what I did is, I developed basically three scenarios. And Case D is a little different. Case A was a 20 percent RPS by 2020, Case B a 20 percent by 2030, Case C, 20 percent by 2041, which is basically the staff draft rule that you saw on October 14th. That's not trickery there. I'm just -- that's the way it fell out.

The cost figures you'll see later will show you -- they don't have the benefits of an IRP process. They're rough estimates, but I think they're useful to give you bounds and orders of magnitude of what these various strategies will require in terms of cost and megawatts that need to be constructed. And finally, I'll discuss the clean energy portfolio, and what I'll do with that one is give you a snapshot in time of where we're at.

I want to make two points with this slide,

first, that the majority of renewable generation in Florida is municipal solid waste and biomass, much like you heard from Navigant. And the 3.6 percent number that you've seen and we've talked about, I want to make it very clear, this number includes not only firm purchases, or sales, I should say, but non-firm sales and self-service generation.

Why that's important is, that's not typically included when you see other pie charts where we've shown you the percent of nuclear generation we have or the percent of gas. That's done on a totally firm, net energy for load basis.

So they're two completely different numbers, and I want to make that clear, because I've seen where this number has sometimes gone in the press or whatever of how much we have. It's a true number, at least from what we've gotten here, but it's not comparable to other numbers that you see, and I just want to caution you on that.

Again, it is different from what Navigant had. We're trying to understand the difference, why. We've done surveys for years on renewable generation, what's out there, and we've come up with roughly the same amount, about 1,000 megawatts of installed capacity. And now we have 1,500, and we're trying to see why

weren't we finding out about these people before, and we are looking into that. Not that I don't trust Navigant's numbers. It's odd to me that they haven't shown up yet with us.

Commissioner McMurrian.

COMMISSIONER McMURRIAN: Thank you. I just wanted to ask you, what is the number that is comparable to the other numbers with regard to -- is it around 1?

MR. BALLINGER: That's my next line.

COMMISSIONER McMURRIAN: Oh, okay. Sorry. Thank you.

MR. BALLINGER: For example, FPL, their firm resources are about 1.3 percent currently for renewables. Those numbers should be in the ten-year site plan review for all four utilities.

And this is data that I used in going through this analysis that we got from the stakeholders as part of the RPS data request. And I just picked solar and biomass, because those seem to be the two typical ones out there. And this is what we got from the Solar Coalition for new rooftop PV, about $196 per megawatt-hour. This is a levelized cost by 2020. And you see for biomass, it's about $120 a megawatt-hour.

Now, this slide, we went round and round in-house, because it is a little confusing, and

hopefully I can clarify it by doing this, because when I tried to do it on a slide, the slide really got messy. When you have these three different scenarios, Case A is 20 percent by 2020, Case B is 20 percent by 2030, and so on. To get any kind of relative comparison, I had to stop everything at 2020 to give you relative magnitudes or how the dollars would change and the megawatts would change. So if you can keep that in mind, it will help.

So what this tells you is that Case A, to get the 20 percent by 2020, I need 44,500 gigawatt-hours of energy from renewables. For solar, in order to produce that much energy, I would need 26,000 megawatts of capacity. That's because solar has a low capacity factor. I assumed a 22 percent capacity factor, which is what FPL has in its solar projects that it's proposing.

You see there we have existing about 3 megawatt-hours of capacity from the prior slide. And then to get the number of installations, I assumed a 4 kilowatt residential PV, which is about an average size. Divided by the 26,000, that's 5.8 million residential installations. As a point of reference, there's about 8.3 million customers today in Florida, so this is telling me that about 70 percent of the existing customers would have to install PV to reach this type of

RPS by 2020.

What this tells you, though, is that as you -- it's kind of intuitive, that as you push the goal out, the amount of megawatts you would need by 2020 decreases, and the amount of money you would need to spend by 2020 decreases. And those numbers at the bottom are net present value in billions of dollars based on the $196 a megawatt-hour times the megawatt-hours that would have to be produced by solar. So if you took the 196 times the 44,500 and then do it each year -- actually, we spread that over years, because that 44,500 is a one-year number. It's not a cumulative.

But what this tells you is that if you went from a 20 percent by 2020 to 20 percent by 2030, it would shave off about $10 billion in present value by the year 2020, and then so on as you push it a little further out.

The installations I focused on, I look at feasibility --

CHAIRMAN CARTER: Will you yield for a moment?

MR. BALLINGER: Sure.

CHAIRMAN CARTER: Commissioner Skop.

COMMISSIONER SKOP: Thank you. Mr. Ballinger, just with respect to the estimated cost, again, being

clear, the cost was provided by the Solar -- what group did you say?

MR. BALLINGER: I believe it was the Solar Coalition.

COMMISSIONER SKOP: Okay. And if that cost on your prior slide is $196 per megawatt in terms of the levelized cost, how does that comport to what New Jersey is currently experiencing, where the price of their REC alone is $711? I mean, I'm trying to rationalize -- you know, certainly there's different ways to advance numbers, but I'm trying to, you know, understand what is a realistic levelized cost, and I find that cost to be somewhat low.

MR. BALLINGER: It may be. I don't know. I will say that a REC price typically doesn't reflect the cost of renewable generation. It tends to reflect the price you'll pay for that renewable generation. So it may be well above the cost of that facility. Again, I took data that we had, that we got through this process to try to lay it out and give you a sense of, depending on what way you want to go, the relative magnitude.

I want to try to point out a couple of things, the magnitude of megawatts, is it feasible, and the relative cost savings you can get from deferring the goal out.

COMMISSIONER SKOP: All right. Thank you.

MR. BALLINGER: Then I took another case and tried to do it, all right, let's do 100 percent biomass, because those are the two kind of competing technologies we have. And as you heard from Navigant, they're a lot less costly than solar. And as you can see here, they have a higher capacity factor. I assumed an 80 percent capacity factor for biomass, which is typical of what we see with a base load plant. Again, that would require much less megawatts to do the same job of 44,500 gigawatt-hours in the year 2020. You see we have 1,000 existing megawatts. So the number of installations by 2020 is about 66.

And based on some data we got from the stakeholders, if all the municipal solid waste, which is part of this biomass product, if all the municipal solid waste that is currently being landfilled now were converted into municipal solid waste for energy, we would do about 1,600 megawatts. You see here, we need to have over 5,000 megawatts installed between then. So even -- what that's telling me is, even if all the waste that's being landfilled were converted to energy, it would not meet this goal of 20 by 2020. That's about 20 municipal solid waste plants, the 1,600 megawatts.

And again, I'm looking at this -- I'm trying

to say, all right, what's feasible, what's realistic, what can be built in a reasonable time frame that's not too overly aggressive. As you see here, and it's no surprise, the net present value is much less, because biomass was assumed at $120 a megawatt-hour.

And then this slide tried to take part of what staff did of recognizing this difference, that there may be more room for development of biomass than solar just based on economics, and split the RPS number, 25 percent to solar, 75 percent to biomass, which is per our draft rule. And what this shows you is it will help reduce the amount of installations necessary from solar. It goes from 5.8 million, I guess it was, to 1.4 million in Case A. And it also reduces the number of biomass installations required from 60 down to 46. This helps make it a little bit more feasible in terms of achievability, of reaching these goals. It's still quite aggressive. But it does increase the cost a little bit. If you go back a slide, the all biomass was 21 billion. The mixture here is 24.5 billion, so it's somewhere in between if you do this mix.

Now I'm going to try to get to the rate cap. Remember, those costs before were the total costs that the renewable would require to stay in business, let's say. But now I'm looking at, all right, to pay that

cost, where does the money come from? And it comes from two sources. It comes from as-available energy prices, which, if the renewable sells energy to the utility, remember, there's no capacity payment because we've tied up our needs. So it would be as-available energy, and then there would be a REC on top of that, an adder, which is what -- the draft rule has come out as an avoided cost-plus kind of a concept.

So I looked at the difference between the total cost of the 196 for solar, let's say, and the as-available energy rate in that year, and that difference became the REC price. And what this shows you is what the revenue cap would have to be to meet those prior scenarios.

So, for example, under Case A, if we did all solar, we would start at a 4 percent rate cap and climb to a 21 percent rate cap by 2020. And that again is trying to meet a 20 percent RPS by the year 2020. And obviously, as you get less and less aggressive with your RPS, the rate caps come down.

As you can see by Case C, if I did it all solar, it would be 4 percent in the year 2008, only climbing to 10 percent by 2020. So it's a much more gradual rate increase as we go through time, because you have pushed out the need for the RPS farther in time.

It gives you a relative feel that an all-biomass plant, again, it had a lower total cost, so it's going to have a lower rate impact. It would climb from 1.5 percent under Case A to 6.5 percent by 2020.

Before I move on, I'm going to get into the clean energy portfolio. And I'll be here. You can ask questions later, but please feel free to stop me whenever. The clean energy portfolio, this has come up in conversation a few times, and I would like to -- the way I kind of view it is, there's really three parts of statutes that the Commission takes into account when looking at IRP and planning in general that help go to a clean energy portfolio.

The first one you see, the statute there is FEECA, and the basic tenet there is to promote conservation, demand-side management, renewable energy systems, and added this year is generator efficiency improvements. The middle statute is the renewable statute where the RPS came from to promote renewable projects, which is more the larger scale renewable projects. Then you have the final statute, 366.93, which promotes nuclear and IGCC generation, and it promotes that from a cost recovery standpoint of allowing early cost recovery for those types of projects.

But all three of those do have some commonality in them. They all have the desire to improve fuel diversity, the desire to reduce greenhouse gas emissions, and the desire to minimize rates to customers. So within all three of these statutes, you have a common tenet.

And what I tried to do here is just give us a snapshot of where we are with a clean energy portfolio. And this one is a little different because of the DSM component. Typically when you look at, as I said earlier, percent generation by fuel type, it's on a net firm basis, which means DSM has already been taken out. Well, to do a clean energy portfolio, I have to put DSM back in as far as how much generation would I have to serve without DSM, and then recalculate the percentages. That's why these will change a little bit. It's a minor detail, but I want to make that clear.

What this does tell me is that -- this is based on the 2008 ten-year site plan data. It only includes firm renewable purchases that are contracted for and when they fall out, and it does not include FPL's new nuclear units, which don't come online until 2018 and 2020.

But what this tells you on the far right side is that Florida Power & Light and Progress Energy are

already above 20 percent of their total mix in -- I'll call it clean resources, DSM, renewable, and nuclear. The other utilities, TECO and Gulf, are not, and it's obvious, they don't have nuclear. And that's the other part of this thing, is that nuclear in a clean energy portfolio is a big chunk of the equation as far as energy. Again, it's because it runs 24 hours a day, seven days a week for a year, year and a half at a time.

An interesting thing here on that note is generation efficiency improvements. That has also been talked about in some components of the clean energy portfolio, that that should be included. The trouble I have with that one is, that's really measured in Btu's of fuel saved, not kilowatt-hours. And I'm not quite sure how to mix that in. That's why I've left it off this chart. Bob Trapp and I went round and round to try to figure it out, and I said, "No, let me just make it a footnote, because I don't know how to do it."

And that's -- in conclusion, I would like to say that I think that utilities need to do a balanced approach to their IRP, to look at renewables and other forms as well. I will say, though, if we go to a clean energy portfolio, it does raise some questions, and it's obvious here: Should utilities who have nuclear power or access to it be required to share that resource with

other titles, should they be required to sell credits, if you will, if we have some sort of a trading market, if you will, for clean energy credits, and how generator efficiency improvements be incorporated into it. Again, I think if we don't take care to make sure the stool stays balanced, we could end up upsetting the balance between reliability and cost.

And again thank you for your patience, and I'll be here for any additional questions. And I can turn it over to Mark, if you would like, now.

CHAIRMAN CARTER: One moment, please. Commissioner McMurrian.

COMMISSIONER McMURRIAN: Thank you. Tom, on page 21 -- and I know we've talked about this before, but I just need -- I think I need a refresher. Can you remind me how you calculate the percent revenue cap? And maybe you just went through it, but if you could --

MR. BALLINGER: Okay.

COMMISSIONER McMURRIAN: For instance, with Case A, the 25-75 split, you have the 2 percent and the 10 percent then by 2020.

MR. BALLINGER: Okay. What I did in Case A, on that one, the 25-75 percent split, I first looked at the total cost for solar -- I'm sorry. That was the mix. So now you've made it really complicated, but

that's okay.

COMMISSIONER McMURRIAN: Well, pick one of the others.

MR. BALLINGER: Let me pick the all solar. The same methodology carries through.

COMMISSIONER McMURRIAN: Okay.

MR. BALLINGER: So for all solar, I would take the $196 a megawatt-hour times whatever megawatt-hours were needed in that year. That gives me one value. And from that I would subtract the as-available energy rate times those megawatt-hours. Okay? That's where they would get paid for the energy, and any remainder would be what the revenue cap would have to be to get me up to 196. Does that make sense?

So, for example, if the rate for solar was 196 and the as-available energy rate happened to be 96, the rate cap would have to be $100 a megawatt-hour.

COMMISSIONER McMURRIAN: Okay.

MR. BALLINGER: And then I just did it as a percent of utility revenues, because that's what we've been talking about. And that same methodology applies through for all.

COMMISSIONER McMURRIAN: And I guess one other question. Earlier when you were talking about after you got some information from the utilities with the data

request and we were looking at this, a percent of retail sales, because that's what the statute said, and you said that maybe some of the data you had suggested that we should look at it on a gigawatt-hours basis. How would we -- I mean, was that something you used for your analysis, or are you saying that that may be something that we might want to recommend, that it might be a better way to go about it?

MR. BALLINGER: That might be a recommendation. It's just something that we observed in gathering this additional data. I was amazed at the impact that a change in forecast would have. When you're looking out, by the year 2020, 2030, a small percentage change in a forecast can make a huge difference in the amount of gigawatt-hours. And gigawatt-hours is what actually gets built, I guess is what I'm -- you know, what kind of dawned on me. But, no, I kept it with percent of sales.

COMMISSIONER McMURRIAN: Okay. Thank you. And I guess later when we hear from other folks, if they have any input on that kind of approach, that would be helpful.

CHAIRMAN CARTER: Thank you.

MS. CLARK: Mr. Chairman, while he has those slides up, may I ask him just for a clarification on a

term he has used?

CHAIRMAN CARTER: No. Sure.

MS. CLARK: It's on page 4, and then also I think on page 5. You used least cost basis and least cost revenue requirements.

Isn't that a little simplistic in terms of what you do? Because you're looking long-term, and you're looking at the lowest rates overall, and you would take into, as you call them, strategic issues that you need to consider. I guess if you were looking at the least cost at any time, you would just keep adding peaking units.

MR. BALLINGER: It is a long-term, least-cost plan, and you do have to take into account the impact on rates. You do have to take into account the impact on the environment, do I need fuel diversity, am I getting too dependent on one fuel, which may cause you to add a little bit more now, hopefully getting long-term savings.

MS. CLARK: So it is least cost, taking into account all those things you need to take into account, where if you were doing it strictly on least cost, you might do one thing, but when you want to assure reliability, the need for base load, you come up with a different number?

MR. BALLINGER: Yes.

CHAIRMAN CARTER: Okay. What I'm going to do is, I'm going to ask the stakeholders if you could just hold your questions. We gave you guys this morning our time, so we won't give it to you this time.

MS. CLARK: I hear you, Mr. Chairman.

CHAIRMAN CARTER: Okay. And after we finish our questions, then we'll go back and let you guys pick up. You all can be cleanup. You all can bat cleanup today, this afternoon. All right?

Okay. Mark.

But we'll come to you. We'll come to you at the end.

MR. FUTRELL: Good afternoon, Commissioners. I'm Mark Futrell with the Office of Strategic Analysis and Governmental Affairs.

My presentation will continue our response to questions raised at the October 14th agenda conference on staff's draft RPS rule, the other issues related to renewable portfolio standards and implementation tools for encouraging renewable energy development. I'm going to address the Commission's implementation of the RPS, as well as regular review of the RPS and oversight of costs associated with the RPS.

Another point that was raised at the October

14th agenda was about the recovery of costs associated with renewable investments by the utilities and cost of compliance with the RPS.

Next there were questions raised about alternative compliance payments or ACPs. And these can be used not only as a compliance mechanism, but also as a cost mitigation tool. Now, ACPs were not included in staff's draft rule, and I'm going to address why that was done in that portion of the presentation.

Finally, I'll address feed-in tariffs, which were raised at the October 14th agenda. Feed-in tariffs is a mechanism that can be used essentially as an implementation tool to encourage renewables, whether or not an RPS regulatory structure is established.

Now, the first topic of my presentation is on Commission implementation of an RPS, oversight and review of the RPS standards set and oversight of RPS costs to meet those standards. Again, my comments in this section will be based on the staff's draft rule.

In this portion, I'm going to hit on four topics. The first is the establishment and ongoing review of the standards by the Commission, ongoing review of the implementation plans by the utilities, detailing how each utility would meet its RPS requirements. Then I'll discuss how the Commission will

consider utility-owned renewable projects and provide ongoing review of project costs. Finally, I'll address the Commission's role in the review of contracts between investor-owned utilities and renewable generators.

Now, as described in October in our recommendation at the agenda conference, staff's draft rule is based on the policies articulated by the Legislature in Section 366.92 of the Florida Statutes. And in trying to meet those requirements, the staff's rule contemplated that initial RPS standards would be established in the rulemaking proceeding. Again, the RPS is defined as the minimum percentage of total annual retail sales by an investor-owned utility to consumers that are supplied by renewable projects in the State of Florida. The draft rule contemplates again that the Commission would establish RPS standards in a rule, as directed by the statute.

And the draft rule included provisions allowing for Commissioner oversight of the RPS requirements in a proceeding at least every five years. In that proceeding, the Commission would be able to take data on utility compliance efforts, the cost of compliance, analysis of the technical and economic potential of renewables as required in the statute, and an ability to determine whether utility compliance

actions were appropriate, and ultimately a review of the standards themselves to determine whether or not any changes needed to be made. Again, in this proceeding, information through these processes would be developed, providing the Commission a holistic view of the performance of the utilities in meeting the RPS, the status of renewable development and performance in Florida.

The next part is the -- the draft rule allows for Commission oversight of the RPS through ongoing review of utility implementation plans. And the rule contemplates that each utility will explain in its implementation plan how they intend to meet the RPS. This would be done initially after the rule becomes final, and they would explain how they can meet the RPS requirements through either utility-owned projects, through contracts with renewable generators for capacity and/or energy and RECs, or through contracts just to purchase RECs only.

Again, the plans would be subject to Commission approval when the RPS is initially set and following the five-year review process. When the Commission takes another look at the RPS, there would be an opportunity for a look at the implementation plans.

Finally, these plans would be reported to the

Commission, and the results and compliance efforts will be reported in the ten-year site plan filed annually, and this will allow the Commission to review how renewables are integrated into each IOU's plan to meet customer electricity needs.

The next portion is, in the RPS statute, 366.92, it states that the Commission's rule shall include methods of managing the cost of compliance with the RPS, whether through direct supply or procurement of renewable power or through the purchase of RECs, renewable energy certificates. So the statute, therefore, contemplates that an investor-owned utility may supply renewable energy directly from utility-owned projects.

And in our draft rule, we crafted language that would provide that if a utility sought approval from the Commission for recovery of costs associated with a renewable project, it must select the resource that most likely will result in the least cost option for ratepayers. And we believe that this safeguard will help ensure that the RPS requirements, coupled with the opportunity to earn a return on a renewable investment, will not result in a perverse incentive for utilities to build renewable projects, but rely on a balance of utility projects as well as purchases of RECs and energy

and capacity from other projects.

The IOUs also in our rule contemplate that they must issue a request for proposals or RFP at least every two years for renewable energy, essentially go out and test the market to see what may be out there and may be available. These results of the RFP must be reported in the ten-year site plan. And when the Commission is presented with a utility project for approval, this information would give it some context as to what relevant costs are out there and potential competing costs to make sure that a project that is sought for cost recovery is meeting the standard of providing the least cost option for ratepayers.

Finally, the statute and the Commission's rule provide -- the staff draft rule provides for authority to provide for annual cost recovery. And we included in the draft rule that costs associated with renewables and the RPS compliance would be recovered in what we call the renewable energy cost recovery clause, and I'll discuss this in more detail later in the presentation.

Next I'll talk about -- the final portion of this section of the presentation will be about approval of contracts with renewable generators. Now, the Commission has oversight of renewable project costs through its review of contracts with renewable

generators and through annual cost recovery proceedings. And renewable power contracts may include provisions for payment for capacity or energy or RECs, or some combination.

Now, since the early 1980s, the Commission has provided oversight of purchased power contracts between IOUs and cogenerators and renewable generators at costs that do not exceed the utility's cost of generation. In 2005, the Legislature, in an effort to encourage more renewable energy development, directed the utilities to continuously offer a standard contract to purchase renewable energy with a minimum ten-year term. Now, the Commission annually reviews these contracts and approves them for availability to potential developers. The Commission also reviews negotiated contracts that are brought before it and determines whether to approve for cost recovery.

As I mentioned earlier, payment for RECs may be bundled with capacity and/or energy payment or purchased separately. This REC would essentially give a renewable generator additional value above the utility's cost of generation.

Finally, the staff draft rule would provide for consideration of the costs of renewable purchased power contracts and costs associated with the purchase

and sale of RECs in the new renewable energy cost recovery clause. And we believe that a dedicated clause like this would give the Commission further ability to provide better oversight of all costs associated with renewables, as well as the RPS compliance.

Now, the next question that came up in October was about recovery of utility investments in renewables. Again, the statute provides for Commission -- that the Commission's rule would provide for annual recovery of costs associated with the RPS. And again, we created the record clause, if you will, which would provide for annual review of costs associated with this laundry list of items, including utility-owned resources, capacity and energy purchases from renewables, as-available energy purchases, purchase and sale of RECs, as well as REC market administrative costs. And we believe this type of approach would again facilitate the Commission's ability to track compliance costs and continuously evaluate cost recovery issues for renewables.

Now, in the staff's draft rule, we contemplated that for a utility renewable investment, the IOU would have an opportunity to earn a return on investments in these projects. The IOUs could earn additional returns on the rate base that would be potentially larger, not just on the additional

investment, but the fact that a renewable investment may in fact be at a higher cost than a traditional utility investment, so there's an opportunity to earn an additional return in that way.

Now, traditionally, costs associated with utility investments would be recovered through base rates, and this could be accomplished through a rate case or some sort of limited rate proceeding. And in a rate case, it involves typically a detailed analysis of all the utility's investments and expenses. A rate case, however, could create a disincentive for utilities to pursue renewable projects due to the regulatory lag of determining the exact costs appropriate for recovery, as well as the rate case complexity and expense.

Also for consideration is that as an alternative to a cost recovery clause, going to a consideration of rate base recovery, is that depending upon a utility's specific earnings position and level of revenues and expenses, it could be able to absorb some or all of the costs of a self-build renewable project and still be able within its last authorized rate of return.

Okay. The next question raised at agenda in October was on alternative compliance payments or ACPs. And essentially an ACP can be thought of as a compliance

mechanism, in that a utility may choose to pay the ACP in lieu of producing or purchasing sufficient RECs to meet the RPS. However, this decision is dependent upon the structure of the RPS and some of the provisions. Again, the devil is going to be in the details here. If an ACP payment is set low relative to the price of RECs, then it acts as a cost cap. If ACPs are set close to the price of RECs, then the utility would be indifferent to whether they're paying the ACP or actually purchasing the RECs or investing in renewables. If the ACPs are set above the price of RECs, then that would encourage investment in renewables. So in other words, the key there is where you set the ACP payment is very critical.

Also critical is the cost recovery provisions of the ACP in the RPS. If it's recoverable from ratepayers, then the ACP acts as a cost containment and compliance measure. However, if it's not recoverable from ratepayers, then it acts as a penalty to shareholders for noncompliance with the RPS. So these details here will be dependent upon the nature and how an ACP can be used.

Another aspect of ACPs are that the funds collected are typically sent to a designated agency, which allocates those funds to one or more of the following uses. Usually it's put into what may be

called a public benefits fund, and it can be used for renewable energy programs as far as grants to encourage projects, to help fund projects, also for renewable research and development, or energy efficiency programs or low income assistance, or even energy education programs. It really varies from state to state, the uses of these funds.

One thing to mention is again that staff did not include this in our draft rule. We did have -- there is provisions in the statute for compliance measures. And the problem we kept bumping up against is, what do you do with the money from an ACP. There really was nothing in the statute that was giving us clear direction on, if an ACP was collected from the utilities, what then would the Commission do with those funds. There's no designated agency set up in the statute to dispense with those funds. There's no direction on, if such funds were collected, where those funds would be directed. So we felt like because of that lack of direction, we didn't feel like we could go all the way down the road of developing ACP language, so we kept it to where it was more just a compliance mechanism of judging whether or not they complied with the RPS, and then give the Commission the opportunity to potentially set a penalty for noncompliance.

CHAIRMAN CARTER: One moment, Mark. Commissioner McMurrian.

COMMISSIONER McMURRIAN: Thank you. I appreciate that, Mark. Did -- and maybe this is putting you on the spot a little bit too much, but did the staff believe that the alternative compliance payment would be a good way to go if you didn't have that issue of which agency would deal with the money? We don't have any authority to sort of answer that kind of part of the question.

MR. FUTRELL: I guess personally, I felt like there were still a lot of details as far as setting the level of the ACP that would be very complicated and would require us to go into a lot more -- we didn't feel like we had the time to go into the depth to really analyze and judge where you would need to set that ACP, because, again, relative to the price of RECs, it's going to be critical where you set that ACP and direct how the ACP is going to be used by the utilities. Certainly, the whole idea of the RPS is to encourage renewable development, to assist those existing renewables, and so it really is quite a Pandora's box that requires a lot of time and thought to develop that. So we felt like given what was in the statute and the time frames we were under, we didn't go down that road.

COMMISSIONER McMURRIAN: And I guess as a follow-up to that, we heard from a lot of the stakeholders that they like the ACP mechanism, or at least they were more familiar with how that worked because it had been done in so many states. And I just can't recall, but were a lot of the stakeholders that were proponents of the ACP, did they also take a position on whether or not it should be recoverable through the RPS mechanism? Because as you pointed out, you know, it could have different incentives on whether or not it was recoverable from ratepayers. Do you recall?

MR. FUTRELL: I believe generally they did. Again, it can be viewed as not just a compliance measure from the perspective of the utilities, but it also can be viewed as a funding source for renewables. And so in that respect, in many states they're indifferent to whether it's an ACP or a REC payment or there's -- it's a funding source. So from that perspective, it's generally indifferent. But certainly recovery, to make sure it's paid is critical.

COMMISSIONER McMURRIAN: Thank you. Thank you, Chairman.

CHAIRMAN CARTER: I know when we went down -- it seems like forever ago when we first started this. I

had some questions about the public benefits fund. We don't have one here in Florida. You know, without having -- I'm just thinking aloud. Without having a depository to put that in where we know that these proceeds are going to go for renewable energy programs, are going to go for research and development, energy efficiency programs, low income assistance, education and all, you know, it's hard to -- you know, to say that, because if you go from the perspective that that's what these funds need to be used for without having actual legislative authority to do so, they could end up in GR. You know what I mean? And then -- so that kind of gave me the willies when I saw that.

But just from the standpoint of that, in the context of -- when we originally started talking about that some states have those public benefit funds. We don't have one here in Florida, and maybe as we do go further down the road and make some kind of recommendations later on as we talk about some of the issues that we may or may not have legislature authority for, maybe we can talk about that as well.

Thank you. Any further questions?

COMMISSIONER McMURRIAN: No, I'm okay.

CHAIRMAN CARTER: Mark?

MR. FUTRELL: The final question that was

raised in the agenda was on feed-in tariffs. And again, these are typically an implementation tool to further encourage renewable generation, and it can be established with or without an RPS structure. It's typically a contract to purchase renewable energy of differing types at a fixed rate over a longer term to improve again the financial viability of getting projects in the ground. Generally these rates exceed the cost of the utility's generation and act to subsidize resources.

Now, also, it should be noted that while it is fixed and it's at an established rate, generally the rates will ramp down over time, recognizing the technology maturement and its cost decline, that it's beginning to approach the cost of utility generation, and the need for that premium declines over time.

CHAIRMAN CARTER: Mark, let me ask you a question before I forget it as it relates to these feed-in tariffs. I notice that in the background information that these are primarily practiced in Europe. And from what I've seen, we don't have any state in the United States that are doing that.

MR. FUTRELL: Actually, while the history is primarily in Europe, we're seeing more and more development of these feed-in tariffs in the United

States. Certainly the most recent example close to home is Gainesville Regional Utilities --

CHAIRMAN CARTER: Now, that was this year?

MR. FUTRELL: Just approved a program a couple of weeks ago, yes, sir. And Bob mentioned that.

CHAIRMAN CARTER: Commissioner Skop.

COMMISSIONER SKOP: Thank you, Mr. Chairman. Mr. Futrell can you also with respect to the GRU -- I mean, although they're calling that a feed-in tariff, at least my discussions with GRU have seemed to indicate that unlike the feed-in tariffs in Europe, which are basically a substantial payback on the investment, the GRU feed-in, or what's being deemed a feed-in tariff by GRU is in fact just monetizing the previously available rebates that GRU offered to residential and commercial ratepayers in lieu of the rebate program.

So effectively, what's being called a feed-in tariff is 26 cents per kilowatt-hour, which is double the retail rate, but certainly not consistent with some of the feed-in tariff numbers that Navigant or others have provided; is that correct?

MR. FUTRELL: That's correct. Certainly in Germany specifically, we've seen that some of the rates are on the order of three times retail rates, so you're correct. But the structure of the Gainesville program

is like a feed-in tariff program.

COMMISSIONER SKOP: I recognize that. I'm a GRU ratepayer, so I have a vested interest in making sure that --

MR. FUTRELL: And also note that in Gainesville they did retain some of the existing program for residential customers and that they can still get a rebate if they install a solar system, take advantage of all the tax credits, and net meter. So they retain that for residential customers. The concern that has been evidently by larger customers that this feed-in tariff system would be more beneficial to them as far as guaranteeing a fixed payment over time.

CHAIRMAN CARTER: And the German feed-in tariffs, they've gone through several iterations since the first time.

MR. FUTRELL: Yes, sir.

CHAIRMAN CARTER: Can you talk about the anticipated results and the actual results as they went through that? Is that going to be part of what you're going to --

MR. FUTRELL: Right.

CHAIRMAN CARTER: Okay. Can you say that now so I won't forget it?

MR. FUTRELL: Sure. Right. Essentially, it

first began in 1990, and over time they've come up with new laws or amended existing laws to try to develop the industry more, as the rates and the programs they established were not sufficiently stimulating the market. And as recently as 2000, a law that was passed substantially increased those level of payments, and it has resulted in substantial growth in solar PV installation. And I've got some numbers in the next slide to talk about that. But, yes, the German program, they have evolved it over time, and it has resulted in substantial, again, PV installations.

CHAIRMAN CARTER: And this feed-in tariff is pretty much a subsidy for different types of renewable energy?

MR. FUTRELL: Right. Typically customers would be charged -- have a surcharge on their bill, and it would go to a fund, and from that fund, it would help UBUs to make the payments associated with these contracts that are signed.

CHAIRMAN CARTER: See, we're going back to the fund deal again that we don't really have. You know, that has been kind of a -- even the first time we went down this road, our first workshop, when I asked that first question about the public benefits funds. And this kind of ties into that in the context where you've

got a subsidy to generate renewable energy, but where's the place for the subsidies as they're collected? And that's kind of -- I'm just thinking aloud on that one. I still don't have my head around that one.

MR. FUTRELL: And again, this next slide kind of addresses some of the things we've talked about. Again, the customers pay a surcharge into a fund. This gives you a relative sense of where German retail rates are. They're roughly 20 Euro cents, which is about 25 cents American per kilowatt-hour. And then the solar PV rate is about 57 cents. And again, this will decline over time. That's built into the program.

And also, they have other rates, differing rates for differing renewable resources. So while this is probably the highest that's there, other resources have lower rates. So just to get a relative sense, it's not all the same price that's paid for other renewable resources. It varies depending upon where those costs are.

Again, between 2000 and 2006, as I mentioned earlier, there has been a substantial increase in generation from solar in Germany, from about 6.3 percent to 11.6 percent.

And again, as I mentioned earlier, we are seeing growth in interest in the United States.

Certainly Hawaii is looking at it and many other jurisdictions, particularly municipal utilities are looking at feed-in tariffs as a means of further developing renewable energy, particularly solar.

That concludes my remarks, and I'll be glad to take any questions.

CHAIRMAN CARTER: How does that -- excuse me. How does that equate in terms of the rates over that period of time? I noticed we spent a lot of time talking about Germany, but how does that equate in terms of rates for them? I notice they had -- you had eligibility for hydro, wind, solar, geothermal, sanitary landfill, sewage treatment, biomass and all. How does that -- in terms of what they were paying before in Germany and where they are now that they have the feed-in tariffs for these different renewables.

MR. FUTRELL: There has been some rate impact on the bill. I can't recall that data exactly, but there has been an impact on rates.

MR. KARNAS: I know the exact number.

CHAIRMAN CARTER: Jerry, you know the exact number?

MR. KARNAS: What happens when you blend all the renewables together, Commissioners -- I'm Jerry Karnas with the Environmental Defense Fund. What

happens when you blend them, the Germans put a priority on PV because they saw that as the biggest job creation potential for them, so they were willing to pay that. But then they had tremendous wind potential, they had tremendous geothermal potential, biogas, biomass, and so that subsumed a lot of the costs.

So what the Germans have paid on average is the equivalent of $2.50 a month American to get the success story that they've had, which is 50 percent higher than what the current rule predicts for us. So they've been able to achieve that with the equivalent of the price of a loaf of bread in Germany.

CHAIRMAN CARTER: Okay. Commissioners, I'm sorry I got off on that. I just had a bee in my bonnet on that one.

COMMISSIONER McMURRIAN: I did have one other one.

CHAIRMAN CARTER: Commissioner McMurrian, you're recognized.

COMMISSIONER McMURRIAN: Thank you.

CHAIRMAN CARTER: Thank you, Jerry. Appreciate that.

COMMISSIONER McMURRIAN: Mark, this was back on page 6 when you were talking about the part about the RPS standards will be reviewed at least once every five

years.

Some stakeholders have told me that they don't believe -- and I think they've said that at some of the workshops too, that they believe it should be reviewed more frequently than that. And I realize by saying at least once every five years, we could do it more often, but has staff been kicking around is every five years, at least every five years the right number or not?

MR. FUTRELL: I guess we felt like that was similar to our FEECA process, in that we look at FEECA goals every five years. And it certainly gives the utilities time to develop a program, begin to implement it, to at least have two cycle of RFPs for renewables to see what's out there.

And again, sometimes these proceedings, as you know, can go on for some time here at the Commission, and it certainly gives them time to get -- but still have our process for to us monitor what's going on. And if we see that compliance is waning, or if there are issues out there in the market, it gives us an opportunity to react and begin our process sooner.

So it's kind of -- we're trying to strike a balance between being over-prescriptive, over -- regulating too much or not enough. And so it's a struggle, but that's kind of the number we settled on

that we felt like would be appropriate and still --

COMMISSIONER McMURRIAN: And I guess it wouldn't just be the Commission that would be able to decide that -- well, I suppose we would decide. But a party or a stakeholder could come to the Commission and say, "We think you need to review it sooner than the five-year plan."

MR. FUTRELL: Right, certainly. Again, the standards as we're contemplating them now would be in a rule, so a party certainly could come and request, you know, that the rule be opened and reviewed, and then the Commission would have the ability to pass judgment on that petition.

COMMISSIONER McMURRIAN: Thank you.

CHAIRMAN CARTER: Thank you. Anything further from the bench?

Thank you, Mark.

MR. FUTRELL: Thank you, Chairman.

CHAIRMAN CARTER: Thank you very kindly. At this point in time, we're going to -- let me check and see how the court reporter is doing. Can you roll for a little while?

Okay. Let's take five minutes so we can do some technical legerdemain here. We'll come back at five after. We're on recess.

(Short recess.)

CHAIRMAN CARTER: We are back on the record, and here's the plan so you can govern yourselves and organize your time. We're going to have -- I'm going to recognize Commissioner Skop in a moment, and after that we'll have a question and answer session. Once we complete our question and answers, we'll have an opportunity for public comment.

We do ask that you would limit your time, because we want to hear from everyone. We are scheduled -- but we will not go beyond -- we'll get there. But again, if you've already made -- I know that in school redundancy is appropriate, but here, you know, if you've made your point, then just let it ride, because we do want to hear from everyone in our public comment section. We'll get back with you on the timing, but when we do get to the public comment section, if you could break it down to about five minutes, that way we can be fair to everyone on that time.

With that, Commissioner Skop, you're recognized, sir.

COMMISSIONER SKOP: Thank you, Mr. Chairman. As Chairman Carter pointed out in his opening comments this morning, the Legislature has mandated that the PSC provide it with a draft RPS rule by February 2nd, 2009.

I'm confident that the Commission will meet this deliverable requirement and will provide the Legislature with the best draft rule possible.

I fully support Governor Crist's vision of achieving a 20 percent RPS by 2020, and in furtherance of this goal, I equally feel, as previously suggested by Commissioner Argenziano, that it would be appropriate for the Commission to provide the Legislature with various options that they may wish to consider during the ratification process. I recognize that I'm not the ultimate policy maker, but as ratepayers, each us has a shared vested interest in sound policy decisions.

My colleagues and I have participated in many different workshops and listened attentively to each of the respective stakeholders and their concerns. From my perspective, I've tried to distill the best ideas from the many competing interests and synthesize them into a workable framework for implementation. With that in mind, I would respectfully like to offer an alternative RPS implementation plan that's based on a standard offer contract approach.

Starting with the first slide, and I guess we can skip the disclaimer, but these are just my personal views. Next slide, please.

The key attributes of the implementation plan

would be the implementation target of 20 percent renewables by 2020, consistent with Governor Crist's vision. The plan would also adopt a revenue cap, as suggested by Barry Moline, the Moline plan. The only stakeholder I think that we have not heard from is T. Boone Pickens. He has a plan. So I guess we can call this the Skop plan.

But the plan would also adopt the avoided cost plus model that staff has recommended, and that would be energy capacity payments plus the inherent value of the RECs. The plan would also include solar rebates applicable to residential and commercial PV.

It would utilize standard offer contracts, providing utilities with a self-build option, so utilization of the existing framework that's well understood by each of the stakeholders and inherently flexible. Standard offer contracts are acknowledged by the Commission, by the utilities, and by developers, and they provide a stable revenue stream that's well understood by the capital market that have to finance such development projects.

Adoption of this proposed implementation plan would also avoid substantial delay and cost associated with developing a captive market for attributes. Next slide, please.

The implementation of the plan would be as follows. I have a graphical representation that we'll get to in a second, but essentially, again, the implementation target of 20 percent by 2020. We would establish a revenue cap. We would fund solar rebates in the amount of 5 percent from the revenue cap. We would establish pricing for standard offer contracts. The energy and attributes would be retained by the utility, and the utility would be able to sell the attributes out of state to offset ratepayer impact, as the attributes would not be used for compliance.

And I want to explain this for a second, because I think this is critically important. Staff had advocated, you know, the change in ten-year site plan, departing from the current legislative mandate of percent of generation. Actually, the Legislature was very innovative in the way they wrote the existing statutory language. As I interpret the statute, the statute requires compliance as a percent of prior year generation.

So therefore, if we move forward with the RPS plan, we essentially attract economic investment in the State of Florida to the extent the generation must be in Florida to qualify, and we get the energy portion of the generation. And for all practical purposes, that's what

the statute requires.

Compliance can be done by the generation of the energy. That frees up the attributes, which, you know, for all practical purposes are -- you know, attributes are -- they're a paper. The price of the attributes is embedded in my plan in the cost of the standard offer contract. So since the attributes are not required for compliance, the utilities would be able to theoretically sell the attribute out of state to offset ratepayer impact. And I think although the value would not be that of a compliance REC, they could be sold certainly for voluntary RECs and out of state.

Additionally, this plan is readily implemented. It could be implemented as soon as 2010, to the extent that if there were legislative ratification of a plan of this nature, implementation plan, the Commission could go into the appropriate procedural posture to again establish the revenue cap and to establish pricing for the respective standard offer contracts. Next slide, please. Thank you.

The next slide shows a graphical representation of the implementation plan, and I would like to -- sometimes a picture is worth a thousand words. And I apologize to my colleague, Commissioner Argenziano, that she's not able to see this. I've given

Larry a copy of it.

The first decisional tree step would be to establish or recommend a revenue cap, and again, that could vary. I know there's competing interests on that, but I'm going to kind of skip the details and pitch the concept. From that revenue cap, 5 percent, or a number to be determined, would be taken and given in the form of solar rebates. It could be the Energy Office or the appropriate agency. Again, the details at this stage are not important. Those rebates would be in the amount of either 1,000 or 1,500 per kilowatt-hour, similar to what the Energy Office currently has, and that would support distributed solar generation at the residential and commercial level.

Certainly there's a need for solar rebates, as indicated by the backlog that the Energy Office currently has. In the current budgetary environment, it's doubtful that they would be fully funded with the appropriation to support such rebates. And I think that this implementation would help that on a recurring basis, to the extent that they would have millions of dollars to offer for rebates. And I think that's very consistent with facilitating consumer adoption of distributed solar PV generation throughout the state on every rooftop, as indicated by Navigant and some of the

other stakeholders.

It's also very consistent with allowing consumers to avail themselves of the Commission's net metering rule, which each of my colleagues adopted, and it's recognized as one of the best in the nation. So I think that that helps in multiple regards.

Some may view that as a set-aside. I view it as a fair rebate that encourages adoption of renewable solar technology.

The majority of the money would be offered in standard offer contracts, and this would be based on an avoided cost plus model, very similar to -- and I'll get to the standard offer. Very similar to what Pacific Gas & Electric offers in terms of their short-run avoided cost pricing.

Now, each of these standard offer contracts would be appropriately priced by renewable type that would be sufficient to attract investment, but not a windfall. And again, trying to take the best ideas that I've heard to date -- and again, the revenue cap came from Barry Moline, the Moline plan. The standard offer concept is familiar to the Commission. Had one not been deferred yesterday, we would have, you know, acted on that. But it's something that the Commission sees on a regular basis. The utilities are equally familiar with

it, as are the developers.

In the standard offer contract model, again, it would be appropriately priced by renewable. And I think we've heard some comments today that suggest that might be a rational alternative. But you would have one for biomass and waste energy, one for waste heat, one for wind, and one for solar.

And getting back to some of the best practices, Mr. Twomey, AARP, as well as OPC have advocated that in a resource constrained environment, certainly getting the most bang for the buck and low hanging fruit is attractive. And I think that, you know, the appropriate signals can be sent where everyone is marginally happy in such a scenario, to the extent that if you have a standard offer contract that's appropriately priced to attract investment, you're going to get that investment. You may not get as much of it as you want because of the resource constraints, but it is what it is. But everyone shares in an appropriately priced contract that would stimulate the adoption of renewables within the state as well as promote economic development.

The key part of this at the bottom left is that the out-of-state sale of attributes may be able to offset some ratepayer impact. I think that's an

innovative twist, to the extent that, again, my reading of the statute, if we bring the deployment of renewables to Florida, the economic investment, which is a value to the State, the renewable clean energy, which is a value to the State, what does the State really care about the attributes? And if we can get what we need and have attributes available that for all practical purposes are thin air and sell them as voluntary RECs to other markets, then certainly our ratepayers are not adversely affected as they would be otherwise. So I think that that's a nice upside.

Next slide, please.

With respect to the standard offer contracts, again, it would be based on an avoided cost plus model that's consistent with the staff recommendation. The avoided cost pricing would be indexed to natural gas, similar to the Pacific Gas & Electric SREC pricing. That's readily available online if people would like to take a look at that.

It also employs time of use. And I'm not suggesting that we go that far, but certainly time of use would be attractive to those renewables that generate at peak. That could also be of interest. And again, the point of this is to just present an analytical framework for implementation, not to hash out

the details.

The standard offer contracts, as previously mentioned, would be appropriately priced by renewable type. The plus component would contribute to that pricing. And in avoided cost under PURPA, you're limited to avoided cost. That's energy and capacity payments. The plus is the plug factor that makes the standard offer contract economically viable to support each respective renewable type. Again, as previously mentioned, the standard offer contract would be sufficient to attract investment. That would be capital costs, plus O&M, plus ROE, plus fuel stock for biomass or others. That one was inadvertently left off.

But mainly, a standard offer contract provides a long-term, stable revenue stream which is required for financing, particularly in light of the tight capital markets. Next slide, please.

Under this proposal of standard offer contract, the utility would also have the self-build option. There are, I believe, utilities in the state -- and again, this is trying to recognize that some utilities such as FPL have taken the initiative and chosen to self-build projects. This recognizes that desire, but equally recognizes that other utilities within the state may desire a more turn-key solution,

and I think the standard offer contract provides that.

The energy and attributes again retained by the utility. That's fair. The utility can sell the attributes out of state to offset ratepayer impact. Again, the attribute is not used for compliance. That's a very subtle, but I think a very important concept.

Another big plus of this methodology is that it utilizes an existing framework. It's well understood, it's flexible, and it could be adaptable to new technologies as they come into maturity.

The other point is that it avoids the substantial delay and costs associated with developing a captive market for attributes. And I think that we've had a long, lengthy discussion on RPS. I can only envision what the discussion would be about a market that would have to stem from that. And effectively, if you embed the cost of the plus factor, be it the RECs, synthetic or virtual cost of the REC, into the standard offer contract, then there's no need for a market. You save millions of dollars and years of delay in market implementation that is otherwise not needed in the captive market. As I believe I've had some discussions with Navigant, typically markets usually work best when they're regional markets. And in Florida, with the FRCC, we're of a peninsular nature, so again, there may

be some economies of scale there to the extent that if we're spending millions to create a market, those moneys may be better spent or deployed towards actual renewables, towards meeting the goal.

Again, the final point is that this would be readily implemented. Again, if the Legislature adopted such a proposal, I'm confident that through rulemaking, or whatever procedural mechanisms would be required, that the Commission could establish the appropriate rate cap and establish the appropriate standard offer pricing for each renewable type that could -- whatever the detailed mechanisms would be worked out, that could be competitively bid under sealed envelope or what have you. Those are details to be worked out.

But again, I think that the conceptual framework is something that is certainly worthy of consideration. If this framework were to gain traction, it might be a viable methodology for implementing an RPS. And I also think that each of these concepts I've tried to articulate here briefly could be readily reduced to draft rule should our staff be willing to do so.

So with that, I think the last slide. And again, I don't know if there are questions or what have you. I can reserve those. I'm sure there's other

questions of staff. But I thought that this was an innovative way of using an existing framework to try and balance each of the respective competing interests and synthesize those best ideas that I've heard and my colleagues have heard from many hours of presentations.

Thank you.

CHAIRMAN CARTER: Thank you, Commissioner. And let me just say to you, I know that you've been involved from day one on this, and I appreciate the amount of work and effort that you've put into this. It's consistent with a lot of what we've talked about here. Conceptually, I think it's a solid perspective conceptually. As I said, the devil is in the details. But I do want to say to you publicly that I appreciate the efforts that you've put forth here. You've listened to -- I mean, you've been here for each one of the hearings, as we all have. You've listened to the parties, both the stakeholders as well as the IOUs. You've listened to the people from the renewable energy community, as well as listened to what the Legislature has told us to do in the context of providing them with a draft rule by February of next year, and also taking into consideration the time constraints that we're in, as well as instead of reinventing the wheel, looking at where we are and what we have to do. So I wanted to say

to you from the standpoint of your efforts, they are Herculean in the concept here. And I did want to say that to you before we got into whatever questions that we may have on that, to say thank you for that.

COMMISSIONER SKOP: Thank you so much, Mr. Chairman, for those kind comments. And also, too, I do respect -- again, I'm just trying to throw out an idea for a basis of discussion as we move forward in trying to provide a draft rule to the Legislature. And if Navigant is still here, it would be interesting to hear from their perspective if they have any experience with such standard offer contracts.

CHAIRMAN CARTER: Jay, you and Ryan and Matt, are you guys still here? Why don't y'all come down for a second, please.

While they're coming down, I do want to just kind of -- as I was expressing my appreciation to my colleague, Commissioner Skop, we did set this as a workshop for the Commissioners, and we do appreciate the comments that everyone has given us and people are still giving to us. But we did want to get to the point -- you know, we've got to start drafting and moving forward. But I did want to say that.

And let me do this. Commissioner McMurrian, before we hear from the Three Amigos, do you want to

make a comment or anything? You're recognized ghost.

COMMISSIONER McMURRIAN: I think you said it well, Chairman. I agree. I appreciate any good ideas put forward, and definitely those of Commissioner Skop. You can definitely tell he has taken a lot of the -- as he said, a lot of the good proposals from different parties. And I'm hoping we get some feedback from it today. I'm sure that a lot of people, they're seeing it or hearing about it for the first time, but I'm hoping that we get some good feedback from folks on it. Thank you.

CHAIRMAN CARTER: Thank you. Commissioner Skop, you want to ask the questions?

COMMISSIONER SKOP: Thank you, Mr. Chairman. Just to Navigant -- and I don't want to put Navigant on the spot. And certainly, again, the scope of work -- and I don't want to get an extra bill for this.

CHAIRMAN CARTER: Yes, stay within the budget.

COMMISSIONER SKOP: The Chairman said we had to stay on cost and on budget, but -- on schedule and on budget. But I would think that Navigant would be somewhat familiar with best prices that are used by other major utilities and whether Navigant in fact was familiar with Pacific Gas & Electric's short run avoided cost SREC pricing for standard offer contracts.

MR. PAIDIPATI: Yes, we're familiar with programs of that type, and they have been successful in the past. And we've reviewed your proposal, and I think it is something that could work in the State of Florida and I think definitely warrants further study as a possibility going forward for an RPS.

COMMISSIONER SKOP: Thank you.

CHAIRMAN CARTER: Thank you. Okay. Let me go to -- you want to go to the parties first and then come to staff, or what -- oh, Mr. McGlothlin, you're recognized.

MR. McGLOTHLIN: Yes, if it's my turn. Thank you.

CHAIRMAN CARTER: It is now.

MR. McGLOTHLIN: All right.

CHAIRMAN CARTER: And what we'll do -- before Mr. McGlothlin starts, what we'll do is, we'll start with Mr. McGlothlin and go to my right. Well, actually, it will just be one, and then we'll start with Mr. Twomey and go to my left.

MR. McGLOTHLIN: Commissioner Skop, let me also commend you for the initiative that this reflects. I certainly appreciate it. It's obvious the amount of attention that this has received.

And as I believe we've made everyone aware,

from our perspective, looking for the model that gives the ratepayers the biggest bang for the energy buck, the sticking point, or one sticking point in the existing draft rule is the allocation of the revenue cap moneys 75-25. And as I look at your proposal, seeing that 95 percent of those revenues are steered toward the technologies and 5 percent toward solar rebates, if I understand correctly, this 5 percent is your version of the effort to provide an additional incentive for the solar technology compared to what was in the draft rule, then we would see this as a vast improvement and something that's very attractive as a starting point.

I do want to ask you to elaborate on what is meant by standard offer contracts appropriately priced by renewable type. And let me tell you what's on my mind. Having been through the cogeneration QF wars, my concept of a standard offer contract is one that's based upon the utility's avoided cost translated into a stream of capacity and energy payments to the QF that's building something that is going to be the substitute for the utility's unit.

And I'm familiar with the concept that you can have a contract, the net present value of which is the same, whether it's front loaded, whether it's heavier on the capacity payments and the energy side, and you can

modify those components and the timing of those components in a way that is attractive to one technology versus the other without affecting the ultimate net present value of payments that the ratepayers are having to bear. And if that is what you meant by appropriately priced by renewable type, then I see that as very consistent with our desire to see the low cost effort.

If, on the other hand, it contemplates an allocation of the revenues that are designed to buttress one technology relative to another, then that would appear to be the format of the existing proposed rule in a different form. I hope I've articulated that in a way you can understand.

COMMISSIONER SKOP: Mr. Chair, let me try and elaborate briefly on each of those respective points.

With respect to the 5 percent that is slated for solar rebates, again, that's just an arbitrary number. It could be, you know, 10 percent. I just picked 5 percent. You know, I tried to just use a number again to advance consideration of a framework that again is probably catching people by surprise. I wish we didn't have some of the rules we did, because I would love to go talk to everyone about it. But again, it's something that I came up with recently.

The 5 percent again supports solar rebates,

which are not gross subsidies. They're rebates. Consumers also have investment tax credits they can take advantage of. They also have our world class net metering rule that the Commission has enacted. So it's win-win for consumers without being a gross subsidy there.

It helps facilitate deployment of that technology, which is good for the general body of ratepayers, because it's not again a full payment or a huge feed-in tariff. It's just merely one portion of something that makes something a more compelling investment. It also helps with distributed generation to the extent that if you had widespread adoption, theoretically, you could reduce transmission and distribution costs, which is good for the general body of ratepayers.

So that number is somewhat arbitrary. It could go up or down slightly.

But obviously, there is a demand, consumer demand for such, and obviously there's a funding problem currently to the extent that there is no rebate funds currently available, but there's a backlog of applications seeking rebates. So I thought that might be an innovative way to -- and addressing one of the concerns I heard from the stakeholders, which was that

the small installer, the residential installer was being left out in the cold and would not have any viable participation in this RPS by virtue of the fact that it would be gobbled up by the big installations, and all the money would go to other places. So this tries to look out for not only the residential and commercial, but it's geared towards the concerns I heard about the small installer. So I think it provides for them adequately to the extent that it provides that stimulus, which is equally good for the economy and equally good for small business.

The 95 percent amount, again, that number is not fixed. It's open to discussion. The devil is in the details, as Mr. Twomey has often stated. Again, I'm trying to advance a framework.

Each standard offer contract is appropriately priced. I agree with you that in the traditional notion of avoided cost, you have a -- using PG&E as an example, because I'm familiar with such PPAs as I did in the wind industry, 30-year contract, 10 years of capacity payments, 30 years of energy payments indexed to natural gas. It seems to me it comports well with Florida. Since most of our generation is heavily dependent upon natural gas, as gas increases, avoided cost goes up. And that's fair to the developer and fair to the

ratepayers. I think everyone understands that.

Since each contract is appropriately priced commensurate with the cost of making the project viable, again, not a windfall, you know, pretty much basic common sense. You have your capital investment, you have your O&M costs on a recurring basis, you have your required return on equity, and then in the cases of biomass or other things, you might have a fuel charge. So that's incorporated in the pricing. And again, a big concern here, not a windfall.

But some renewals by virtue -- and the Navigant study concludes, you know, pretty much what I concluded. Some renewable types are inherently more expensive than others. And again, as I stated previously, I wish that I could wave a wand and make the economics of solar better than they currently are. But I can't do that. It is what it is. So we need to recognize that those renewable types in a balanced renewable portfolio standard are part of the equation. It's just that affordability is a key driving concern.

So if you have the majority of money going into standard offer contracts, obviously, and each contract is appropriately priced for the resource, then as I previously stated, there are going to be takers for each contract, because it's going to be priced

appropriately to attract investment. But you will be capacity limited because we're constrained by funding.

So you'll have some for solar, some for wind, some for waste heat, and some for biomass. But obviously, as you stated, biomass and waste energy and waste heat are substantially more cost-effective than some of the other renewable resources, and at least for biomass, it's basically base load generation. You do get a lot of bang for the buck, and that's consistent with Mr. Twomey's low-hanging fruit concept. You get the lowest cost alternative that meets the statutory definition, and you incentive that. And that's also equally very important to achieving the Governor's stated goal, because again, if it's generation based, the more generation you get, the easier it is to comply with an RPS target.

So again, wind and solar, intermittent resources, very important. The good thing about such resources is that they are truly emission-free, where biomass, again, there's competing arguments. But everything, you know, is on the table. The devil is in the details.

But again, what I was trying to avoid here is substantial infighting between the various renewable types, to the extent that their contract would be priced

such that they could take advantage of it without pricing -- I mean, without concerns, and then -- you know, again, not trying to get into too much details, but another concern I've heard from consumer advocates, Mr. Twomey, Retail Federation, and OPC, is that you want to get the best overall cost, so you could have a Dutch auction, a sealed bid auction where the price is established, and those that come in under target price, the cap, get the capacity award, and those that are higher priced don't. But again, those details would need to be worked out.

But I assure you that if a resource is appropriately priced, it will attract that investment. But I'm equally cognizant of the resource constraint that's there. The more expensive the alternative, the less capacity you're going to be able to afford.

MR. McGLOTHLIN: Thank you for that. I understand better now.

Given that the price is going to be different under this concept for one technology than for another, would that involve some decision as to how much of the revenue cap to place on each standard contract?

COMMISSIONER SKOP: Yes, sir. Again, looking at the graphical representation -- and I don't know if the slide -- I don't see Chris. But the first decision

would be to set the revenue cap, and everything falls out from there. You have a portion that goes to solar rebates, and the remaining portion, the residual goes into standard offer contracts, and that's a pool of available money. And it would be appropriately driven by the cost of each standard offer contract and the capacity, and you would have to make a policy decision on which of those -- obviously, wind and solar are inherently more expensive than waste heat and biomass and waste energy. So that's a policy decision on what you need to do. And you may see some sort of balancing, but again, I think that it's fair.

And to go back to your concept just briefly about avoided cost and the PURPA ramifications of that, the plus part of the avoided cost plus model comes from the revenue cap. It is a consumer contribution. So you're not in violation of PURPA, or you're not violating avoided cost. Avoided cost is still there. It's just that the cap money makes that renewable type economically feasible. And you're paying for inherently the attributes that later the utility could theoretically sell in a voluntary market to help defray some minor portion of that cost.

But again, I don't feel that the attributes necessarily under the current statute have to be used

for compliance. If the goal is to attract economic investment and to generate clean energy in Florida, I think both of those requirements would be met pursuant to the statute, leaving the attributes untainted and therefore marketable. It's just that the consumer by virtue of the standard offer contract using the avoided cost plus model would be paying for that premium in advance, and then you get what you get in the back end of it by being able to sell the attributes that Florida would not need.

MR. McGLOTHLIN: And as you visualize it, while these are deemed standard offer contracts, there would be the ability or the opportunity to couple that with an RFP process where you say, "This is a maximum. To enhance your prospects, bid us the lowest you would accept"?

COMMISSIONER SKOP: Certainly that would be a detail that I would be open to. Again, I'm sure there would be debates on both sides. But again, it seems to me that competitive bids is a good thing by virtue of a free market, and I think that we all strive to have the lowest possible cost of incremental generation, and so I think that inherently that would be a good idea. And once the price cap or the pricing for each renewable type was set, then certainly those that can be more

efficient are more likely to get that capacity award in an RFP process.

CHAIRMAN CARTER: Thank you.

MR. McGLOTHLIN: Thank you, Commissioner.

CHAIRMAN CARTER: Mr. Moyle.

MR. MOYLE: Thank you. Jon Moyle on behalf of Wheelabrator. And I too commend you for putting the thought into this and recognize that it's a broad brush approach and there are a lot of details to it. I have just a few questions, maybe points of clarification.

Referring to your chart, which is helpful, that has the implementation plan on it, I understand in your discussion with Mr. McGlothlin that what will likely happen is that the 95 percent that is shown going into these four buckets will then be further divided in some percentage into each of the four buckets; correct?

COMMISSIONER SKOP: It wouldn't be percentagewise. It would be driven by -- the 95 percent represents a pool of revenue resource, basically avoided cost plus the revenue cap. So basically you have those two together, and that basically allocates by renewable type into how much capacity based on the pricing. And obviously, you would want to avail yourselves, as consumers and ratepayers would, of the most attractive alternatives. I mean, without getting into the details,

do I think there will be adequate opportunity for both waste heat and biomass and waste energy? Absolutely.

MR. MOYLE: But biomass or waste energy is not going to be competing against solar in some kind of a, you know, come in with your best bid; correct? They'll be separate categories?

COMMISSIONER SKOP: Separate contract, separate category.

MR. MOYLE: Okay. And currently standard offer contracts are put out there, and oftentimes people are able to negotiate off of those. If I understood sort of the idea, it seems that that would be precluded, because you would have at some point a competitive bidding process for each of the renewable resources. Is that correct, my assumption?

COMMISSIONER SKOP: I think one possible way -- and again, I'm trying to refrain from getting into the details so this doesn't turn into a lock-the-door free-for-all. But one way I could envision it, if the Legislature delegated the authority to the Commission to set a reasonable price for each of the renewable types, then the Commission could undertake that under a sealed, you know, super secret type, here's the maximum price possible. Then the utilities, who also may desire to self-build in that scenario, obviously, they could not

be privy to the sealed price. Everyone is on equal footing, everyone bids, and those bids that are lower than the sealed price ceiling would be accepted up to a certain capacity.

MR. MOYLE: From lowest to highest?

COMMISSIONER SKOP: Something like that, yes.

MR. MOYLE: And then with respect to setting the price, that would be done by the PSC; correct?

COMMISSIONER SKOP: I could envision that one alternative would be that the Legislature would delegate the PSC with sole authority to do that, and that might also prevent some of the infighting and protesting that has gone on historically with renewable contracts.

And what I'm trying to do conceptually is, you know, take all the various competing interests -- and under the existing staff plan, there's just one slice of pie, and so everyone is going to be fighting for a slice of that pie under a renewable type. Here I'm trying to break it out into standard offer contract that's appropriately priced, so hopefully those that want to do biomass aren't at the throats of those that want to do solar. Everyone one is marginally happy, or should be marginally happy.

CHAIRMAN CARTER: Commissioner McMurrian.

COMMISSIONER McMURRIAN: I want to follow up

on what Mr. Moyle is asking, or some of the points he's raising, but not as well articulated. So if there's a standard offer contract for waste heat and solar, or -- well, it really doesn't matter which ones, but we definitely want solar in there versus waste heat. And if a utility had, you know, just numerous offers for waste heat as well as offers for solar, if they could meet their 20 percent with waste heat alone and that would probably be a cheaper option, would the utility have to use all waste heat because that was the most cost-effective option? Or have you not -- I mean, I'm not trying to --

COMMISSIONER SKOP: No, that's an excellent question, and I think I've fielded that question once. And that's one of the details. Again, the devil is in the details. Certainly, as I envision it, it could be going with the cheapest alternative first, the low-hanging fruit concept of Mr. Twomey.

But I think an equally viable methodology would be that each of those respective categories would have a certain capacity in each utility's service area, and the utility would take, you know, the appropriate amount of each, as perhaps mandated by the Commission. You know, if the pricing is such that each renewable attracts investment and you're constrained by dollars

available, then certainly a policy decision would need to be made on where do you spread the money to get the best bang for the buck, equally recognizing that diversity in renewable sources is analogous to balanced fuel supply. And some resources inherently are significantly more expensive than biomass and significantly have much lower capacity factors and are intermittent resources as compared to other alternatives.

So it's a value judgment that kind of works itself out to the extent that everyone gets to participate. It's just that those that desire to participate more that are more costly may not get to participate as much as they would like to in a resource constrained world.

COMMISSIONER McMURRIAN: One other --

CHAIRMAN CARTER: You're recognized.

COMMISSIONER McMURRIAN: One other question. And I doubt this would happen, and I guess it depends a great deal on what the price, the appropriate price would be set for each of these contracts. But what if you had a utility that put out RFPs in all these areas and they got nothing? Would they need to build everything to meet their 20 percent then, or would there be any kind of penalty?

COMMISSIONER SKOP: That's --

COMMISSIONER McMURRIAN: Is that more the details?

COMMISSIONER SKOP: That's one of those details, a "what if." I would think that if they were appropriately priced, that one of two things would happen. You know, certainly our respective IOUs are very well managed throughout the state. Each of those have their own technical expertise areas. Some again have competencies in renewables that want to participate actively in self-build, and I think others will be looking for turn-key solutions. So I think if the pricing is right, you'll attract investment, and I think that's what we want in the state, not such that it's a windfall, but, you know, build it and they will come. So if you price it appropriately, you'll attract that investment.

CHAIRMAN CARTER: Thank you. Mr. Moyle.

MR. MOYLE: Just one brief other area of inquiry. Let me just sort of use an example and see if I can understand. I believe the City of Tampa has a waste-to-energy facility that they own. My client operates it. The Legislature in its statute said that one of the goals is to protect existing resources, so I assume an existing waste-to-energy facility would be

able to avail itself of this standard offer contract; correct?

COMMISSIONER SKOP: That would probably be a legal question to the extent that those facilities that are already legally bound to existing contracts, you know, I don't know whether they would be able to avoid their contract on the basis of a better offer. You know, it's not retroactive ratemaking or retroactive RPS. Certainly I think it would qualify, though, for all new existing generation coming into the state.

MR. MOYLE: Okay. Making it easy maybe, let's say the contract expired and they were up for a new contract.

COMMISSIONER SKOP: Absolutely, absolutely.

MR. MOYLE: So the contract expires and they're up for a new contract. If I heard you, the pricing would be based on capital and O&M and return on equity in terms of setting the standard offer price. The curious part that I was trying to better understand is the REC. You said that the REC would be embedded in the price to be paid for the standard offer contract?

COMMISSIONER SKOP: Right. Let's just do an illustrative example. I'm going to pick solar that's near and dear to my heart. Let's say the avoided cost, subject to check and on the basis of discussion, was

$90 per megawatt-hour for avoided cost, energy and capacity, all in. That's just hypothetical. But the cost, the true cost of solar was $250 per megawatt per hour. Therefore, the revenue cap and the avoided cost plus model would have to fund that incremental difference between the 250 and the 90, which, if I think I did my math right -- help me out, Mr. Chairman, but I think it's $160 per megawatt-hour. And that would be funded from the cap.

So again, the economics start to work out that some renewables that are more expensive again are going to be driven by the amount of money available, whereas other renewable sources, say, biomass was competitive at 90 or $100 per megawatt-hour, again, it provides an economically feasible alternative. I mean, if I had to spread some numbers for sake of discussion, you know, certainly biomass would have their fair share.

Waste heat, I'm not so sure we'll have any more phosphate plants coming in, so again, waste heat may be, you know, subject to reenlistment on expiring contracts. I don't know.

Wind and solar are certainly emerging technologies that are ripe for development within the state, and they would get their appropriate share.

Again, those details would need to be worked

out, but, you know, I think that we're all looking to try and get the best value for our investment, but be fair to everyone such that everyone is marginally happy and can live with the RPS that would be ratified.

MR. MOYLE: And I guess the --

CHAIRMAN CARTER: This will be your final question. I want to get every --

MR. MOYLE: I hear you.

CHAIRMAN CARTER: I'm looking at the clock. I want to get everyone in, so let this be your final question.

MR. MOYLE: Okay. You talked about the REC as being a piece of paper, and it's a property right. The Tampa Bay facility does this. The REC embedded cost is part of what it gets. Then does the utility -- let's say it sells it to TECO. Does the utility have the ability to say, "Hey, I got this REC as a result of this standard offer contract," and then they go knock on the door of Alabama Power and sell that REC to them, as compared to, you know, Tampa Bay selling it directly to them?

COMMISSIONER SKOP: As we've been through this discussion in previous docketed mattes, there's a difference between a voluntary REC and a compliance REC, and I think it would be dependent upon each respective

state's RPS, to the extent that, you know, what they would consider a REC to be utilized.

As I view it, in Florida, as we require our utilities to generate in-state, and if they were the purchaser of the -- or the buyer on the standard offer contract side, they would get the energy and the attributes. To me, energy and the economic investment are the two driving factors for compliance with the RPS, which would leave the REC still in its virgin state such that it could be theoretically sold as either a voluntary or perhaps a compliance REC. It depends on how liberal other states were in terms of their policies, but certainly a compliance REC would warrant a hefty premium over that of a voluntary market REC.

MR. MOYLE: Mr. Chairman, thank you for your indulgence. That's all the questions I have.

CHAIRMAN CARTER: Thank you. Mr. Twomey. I'm trying to make sure that I give everyone an opportunity. I'm going to defer my questions to Commissioner Skop, but I want to give you guys as much of an opportunity as possible. Mr. Twomey, you're recognized.

MR. TWOMEY: Mr. Chairman, thank you. You wanted us to keep our comments or reactions to his plan, not the staff at this point?

CHAIRMAN CARTER: Well, here's what we can do.

Your comments to staff's plan, as you can --

MR. TWOMEY: I have a few just brief questions of the staff, but I had the impression you didn't want to intertangle that with comments on Commissioner Skop, but it's your pleasure, of course.

CHAIRMAN CARTER: Well, let's do this. I mean, this is -- what Commissioner Skop has presented is new. Obviously, you know, our rule is here, so we don't -- we just got it too, so it's -- we do want to hear from that, but let me just kind of hear from you on his plan, and we'll come back if we have appropriate time and get your comments on staff's plan. If not, you can give them to us in writing.

MR. TWOMEY: Okay. I had questions of the staff, but with respect to Commissioner Skop's plan -- let me introduce myself. I'm Mike Twomey. I'm an attorney for AARP, who still has over 3 million members in the State of Florida, many of them served by the five investor-owned utilities regulated by this Commission.

On behalf of AARP, I want to commend Commissioner Skop for taking the time and effort to prepare and present this plan. It represents a little bit of thinking outside the box. We appreciate his effort to meet the needs of most of the stakeholders in this process.

And I think irrespective of where you come down on the details, the numbers that go in the boxes and how many boxes you want to have on the implementation plan slide, there are advantages that commend the plan, I think, that should be forwarded to the Legislature in some form, because it deals -- like he said, it deals with knowns, things that we're all familiar with working with, the various forms of contracts. There's an awareness of these and a familiarity. And above all, it would speed the implementation of the whole process, as he pointed out, which is a key thing.

Very briefly, that said, and the devil being in the details -- and I haven't had a chance to show this to my client, of course, but again, it comes to the numbers and the number boxes you have.

The 5 percent solar rebates on the surface is not a huge number. It does sort of benefit the installers and the like. It basically is a substitution, if you will, or an addition to the legislative program that provided rebates, for which there's no longer adequate money and may not be funded in the next session.

The 95 percent, of course, goes into those four boxes, and I think as Public Counsel has said

before and I have said before on behalf of AARP, we would prefer that instead of four boxes, there just be one, and that all the remaining moneys -- and of course, we agree with the cap and are sticking with the 1 percent cap because we think it's easier. First of all, it's cheaper for the utility customers in this state, especially in the hard times we face now and going into the next year in the recession.

But you take the money -- we would just have you take the money from that cap, the 95 percent that's left in this example, and put it all in there and have the competitive bidding, the Dutch auction, reverse auction, however you want to describe it, where the utilities would be required, they would be compelled to seek out the least cost renewable for the benefit of their customers at the least cost, the renewable at the least cost.

So if Mr. Moyle's clients came in, there was an RFP and they came in and they had undercut the other renewables, they would get as much of the contracts as they could supply. And if they didn't meet all of it for a given utility, then whoever was the second least expensive would get what they could supply, the third least expensive, and so on. That's the way the free market system works in this country, and it's the way it

should work here.

So again, we commend Commissioner Skop's efforts on this. There are a lot of excellent features to it. It should be advanced, I would say to you, to the Legislature in some fashion or form. They're going to be doing a lot of work at the Legislature anyway on this whole process. And then we could talk about the number of boxes and the number of percentages and dollars that go in each box.

But we commend you for your efforts. Thank you, sir.

CHAIRMAN CARTER: Thank you, Mr. Twomey. Ms. Brownless.

MS. BROWNLESS: Thank you. Well, as you all know, because we have spoken with each of you about our idea with a standard offer contract, so we're very supportive of this concept. We think it's workable. We commend Commissioner Skop again for putting the time and effort into it.

We have also done an economic study that reinforces what Commissioner Skop has said. It's doable, it's quick, it's instantly -- or not instantly, but fairly instantly in the regulatory business, put into effect.

A couple of points that I would just like to

make. With regard to the categories of facilities that end up in the distributed generation pile, I assume, or I would hope that there would be different categories there, residential, commercial, so that the one-time rebates would match different megawatts or kilowatt-hours. Is that what you have in mind?

COMMISSIONER SKOP: Just briefly, it would be tied, similar to current Energy Office rebate policy, I believe that it was 1,000 or 1,500 per kilowatt installed, so there would be rebates available up to perhaps a maximum cap. I don't think they would be unlimited. Again, that would be one of the details that need to be worked out.

MS. BROWNLESS: So that might come under the category of solar hot water under 2 megawatts or something like that.

COMMISSIONER SKOP: I believe, at least from what I've heard, again, I would be open-ended to whatever is the best policy for the state. And certainly solar hot water heaters are something I know Commissioner Argenziano has expressed a desire in. I've heard stakeholder input from them. I'm not opposed to them, and to me it would be a fair rebate. So again, I'm not overly critical of that, because it facilitates deployment of those technologies to some degree, along

with the other federal tax incentives and the net metering on the solar PV. So again, I think it's part of the solution. It's not a windfall by any means. I think everyone could live with whatever would be deemed appropriate policy for the state. So if the Legislature thought that solar hot water heaters, solar thermal should be in there, then personally, I have no problem with that.

MS. BROWNLESS: Okay. And if I could just ask a few follow-up questions on the standard offer contracts. We certainly support that concept. That's what we advocated.

We agree with you that, obviously, if you're going to incent somebody, you have to give them enough money to build the type of technology they have, and these technologies vary in cost, with solar and wind being more expensive, obviously, as you've heard everybody say.

Our idea would be that once you have these standard offer contracts out there, they're out there, and people can accept them or not accept them for each investor-owned utility, and that the containment, the cost containment factors would obviously be the amount of revenue you had to spend, and also the number of megawatts bid. So I don't know, I guess, that I think

there needs to be any elaborate extra separate pots set aside. I think once the standard offer contract price is set for each technology, that may work itself out in the big scheme of things. There's only so many places one can site large PV farms in the State of Florida. There's only some much of that you can get, so that all might work out.

So generally, we're extremely supportive of this idea, and we appreciate your effort.

COMMISSIONER SKOP: Thank you.

CHAIRMAN CARTER: Thank you. Ms. Clark.

MS. CLARK: Mr. Chairman, we don't have any questions. We certainly appreciate having it put out there so we have time to look at it and digest the concepts and what the details might be, so thank you.

CHAIRMAN CARTER: Okay. Mr. Karnas.

MR. KARNAS: Thank you, Chairman. I'll combine my comments, because --

CHAIRMAN CARTER: Okay. That will be fine.

MR. KARNAS: -- they're very similar to what I was going to talk about later.

This is a huge step forward in this discussion. We're now moving, thanks to Commissioner Skop, in the direction of where Chairman Carter set this out, to get the best RPS in the nation.

The lessons that we've learned from renewable policies over the past 20 years or so is that long-term, fixed price contract RECs are what works. You know, that's what 45 countries have done, 18 EU countries, and now we have Hawaii, California, Illinois, Michigan and Minnesota considering the same thing. Los Angeles and Gainesville are doing something very similar as well.

And why are they doing this? Well, they're doing this because -- I think this is what Commissioner Skop has begun to understand, that every economist that has looked at a tradeable REC program, an SREC program, which is what the current rule is, to a long-term contract REC program, has found that consumers get more bang for their buck under a long-term contract scheme.

Lord Andrew -- Nicholas Stern did the climate report for Britain, for the National Plan for Climate Change, and found that this was the most cost-effective renewable policy. Ernst & Young found the same thing. The International Energy Agency found the same thing. And unfortunately, Lehman Brothers and Goldman Sachs found the same thing, but I'm certain that it wasn't their energy analysts that sunk them, so don't use that as a black mark.

And why would you go this route? Well, it delivers more capacity. It delivers it more quickly.

And why does it do that? By enabling participation by everybody.

So what are the problems with this tradeable REC that we've been considering here? Well, the New York Stock Exchange is not doing well, but largely historically has been a pretty good market. It has billions of trade. It has huge liquidity, and there's millions of counterparties. In an SREC model for a state like Florida, we're going to have minimal counterparties, and we're going to have very little liquidity, and we're going to have few trades, and you have the potential to have quasi-monopolies, so we don't get investment security. What Commissioner Skop has provided us here is investment security.

A couple of different things on the proposal. I don't think that there's any need to bifurcate for the solar rebates. You can offer long-term contracts to residential and commercial users as well. You don't need -- that way, those folks can go out and get 90, 80 percent financing for their projects, so it makes the rebates not as necessary because they have the long-term contract.

Another thing that you could do, I do think there should be more boxes, not less boxes. We should be looking at wave and ocean technology in the State of

Florida. If people can provide projects, we should be looking at it.

We also should be -- you know, added to this, I believe, is just the general concept that's necessary for renewable energy, which is priority access to the grid.

It was interesting, you know, listening to the discussion about Germany. The reason why they adopted this policy was because a city called Aachen in 1993 adopted this policy themselves, and by 1997 they had three problems. One, they had Vladimir Putin using natural gas as a geopolitical weapon. Two, they had a unification issue with eastern Germany, where they had a terrible economy and a dragging sector from eastern Germany. And three, they had climate and environmental concerns.

So here in Florida, we have actually almost the same mirror image. We have a municipality forging the way on this type of proposal, we're in terrible economic straits, we have climate concerns, and we also import 90 percent of our energy. So this type of policy is good for Florida. It's very similar to why this happened in Germany. And what they really did in Germany is, they went from 2 percent to what will be at the end of this year 18 percent, so they really show

what's possible.

The other things to address, sort of what Mike Twomey said, is that you could add an aggressive digression scale to the standard offer contracts to protect consumers. You know, that's something that -- you know, we've never mandated that for fossil fuels or for any other conventional technology, but for renewables, I believe people believe we can mature the markets quickly enough that they can meet aggressive digression pricing schedules. In Germany, they've averaged 9 percent every time they set the price for PV.

So those are my comments, but I think this is a big step in the right direction, and I thank the Commissioner for putting it forward.

CHAIRMAN CARTER: Thank you. Commissioner Skop.

COMMISSIONER SKOP: Thank you, Mr. Chairman. And I would just like to thank Mr. Karnas for his comments.

With respect to some of the concerns that he raised, I would respectfully suggest that bifurcation would be a good thing as opposed to not bifurcating, as he suggested, just to the extent that it promotes the existing net metering rule that the Commission has. It's readily applicable to an existing framework

utilized by the Energy Office. It has undoubtedly been successful to date, and would be even more successful if appropriate resources were available for appropriate funding to continue that effort.

And just briefly, to comment on the four boxes, it's not limited to four boxes, but that's why this model or framework is inherently flexible. As those additional technologies that have promise mature, such as tidal, current -- Florida probably doesn't -- as Navigant stated, probably doesn't have good wave energy potential. But as those technologies mature and are worthy for deployment, then certainly additional boxes could be added as they're appropriately priced. So everyone wins. It's just that I focused on the mature technologies that are readily viable in Florida today.

CHAIRMAN CARTER: Thank you.

MR. KARNAS: Just one comment on the bifurcation.

CHAIRMAN CARTER: It's your final comment.

MR. KARNAS: Yes, the final one. There could be a choice. Residential consumers could either choose net metering, or they could choose to go to a long-term standard offer contract at a fixed price. So I agree with that. I think that --

COMMISSIONER SKOP: Agreed. I mean, the

details would need to be worked out. Thank you.

CHAIRMAN CARTER: Thank you. You're recognized.

MR. REEDY: Bob Reedy from FSEC. I'll address actually both the standard offer to begin with, and then lead to just a comment, a few comments about the staff's proposal.

And it would be to be caution everyone that with solar energy, it's so modular and so incremental that we get confused. I do it myself, having come from the utility industry for many years. But we think of large central station PV as the way that a utility project would be. But, of course, as shown around the country, Southern Cal Edison we talked about earlier, you can electronically add these things up and make a very large project out of very small incremental places.

So as we structure either one of these plans, we need to be careful that we don't force ourselves to say it has to be a large farm somewhere. In fact, as we know, with land in Florida, that's not a very good idea, because it covers the green things. So keep that in mind as we wrestle through these.

And the rest of these comments also have to do with sort of the solar doesn't fit model. And I'll mention that we keep talking about cost. Tom

Ballinger's presentation showed $196 a megawatt-hour. That's okay maybe today, but everyone, Navigant, DOE, FSEC, we all agree those costs are dropping very rapidly, unlike all the other technologies that are heavy in steel and labor and traditional commodity costs that are trending upward. So when we do our economic modeling, we're always confused with something that's going down while everything else is going up, and we have to work that through.

The other thing is the comparison of peak load and base load. I don't mean to insult anyone by reminding you, but the PV is on-peak, and really so is solar thermal on-peak as opposed to base load.

That then leads to the final comment, and it's a little off this docket, and that is a comment about third party sales. We really have to address that very soon. Ninety percent of the solar energy sold in 2009 is going to be under a PPA arrangement, but not Florida, of course, because that's currently blocked by the PW Ventures decision in the '80s, and even more recently by net metering. The otherwise most excellent net metering rule has a prohibition against third party ownership.

I actually endorse the idea that you should not be allowed to cherrypick base load, which is what PW Ventures, in my view, was mostly about. But here we're

talking about cherry -- not cherrypicking, but sour orange picking. You know, you're taking away that worst load that the utility doesn't want to serve, which is a peak load in the afternoon. And it really calls for a reassessment of that decision so that we can go forward with something that makes sense for both considerations.

CHAIRMAN CARTER: Thank you. Commissioner Skop.

COMMISSIONER SKOP: Thank you, Mr. Chairman. Just a quick response to that question. Again, I tried to consider the third party involved. I know that has been a concern, but frankly, as the controlling law of the State of Florida, I really don't see PW Ventures being overturned. But I don't see how that would preclude developers and participants from investing in the State of Florida and supporting our economy, because, again, the homeowners or the commercial businesses that want to avail themselves of solar can do so through the solar rebates.

And again, the percentage is not fixed at 5 percent. If I heard you correctly, I think that you would advocate for more rebates. Well, rebates are cheaper than standard offer contracts, at least from my view, so again, there may be flexibility there.

But at least my understanding is that as part

of the regulatory compact, I mean, the utilities have the inherent right to serve their load. And by entering into a long-term standard offer contract, either with developers, whether they source the site on top of the roof of Wal-Mart or wherever, it's not a third party. It's a standard offer contract. It's familiar. It comports with Commission precedent and the laws of the State of Florida.

And I think that's equally compelling for any developer to have a long-term, stable revenue stream that's necessary secure financing. I think that the proposed solution adequately protects the interests of all the individual stakeholders that I've heard advanced and provides open and equal participation for all those that would deem the desire to participate.

CHAIRMAN CARTER: Thank you. Mr. Jacobs.

MR. JACOBS: Thank you, Mr. Chairman. I'm Leon Jacobs on behalf of the Southern Alliance for Clean Energy and the Natural Resources Defense Council. We again would like to thank Commissioner Skop for putting forward a very insightful and thoughtful concept. We believe it absolutely warrants further study and probably serious consideration for sending forward.

Just two basic observations and one clarification, if I may. One of the fundamental

decision points in establishing a revenue cap is that you decide -- you make a value decision. You decide that the protection of the community of revenues from the industry is of some level of importance, maybe more important than growth of a renewable market in Florida. I'm not saying that that's the idea here, but I would just urge you to be very careful in considering how to incent the long-term growth of a renewables market. If you're going to do any kind of a cap or cost restriction concept, I think that's absolutely viable, absolutely critical as you move forward.

One other idea that actually segues from Mr. Reedy's point is that not only do I believe that you can have -- that the third party idea has value, but the idea of distributed generation in and of itself has incredible value for Florida.

I may be mishearing, but I think that I'm hearing somewhat of a priority on resources in this proposal that have capacity features in addition to energy features, and I would highly encourage you to give some thought to the real honest-to-goodness benefits of a distributed generation strategic initiative. Where we have a state that has had serious issues in storms, where we have a state that has very serious issues with transmission, where we have a state

that has very serious issues in natural resources to site new plants, the idea of motivating and promoting distributed generation, which I think is very conceivable in your concept, I would suggest to you deserves further consideration.

And then finally, in earlier discussion when we were talking about the RECs and whether or not a utility could sell a REC to an out-of-state utility, is it my understanding from what I read that that particular REC would not be available for compliance in Florida if that sale were to occur?

CHAIRMAN CARTER: Commissioner Skop.

COMMISSIONER SKOP: Thank you, Mr. Chairman. Let me briefly respond. My understanding of the reading of the statute, consistent with the legislative intent, is one to encourage economic investment in the State of Florida. That happens by virtue of the requirement that the energy generated by the renewable resource be generated within the State of Florida itself.

So if under a standard offer contract, the utility gets the energy and the attributes, and the compliance with the RPS target is based on a percentage of past year generation, then the energy generated, the clean energy, being the electric itself, to me comports with the requirements of the statute itself. That

leaves the attribute that is being already paid for with the premium of the avoided cost model in its virgin state such that the utilities that own the energy and the attribute are able to theoretically sell them either as a voluntary REC or as a compliance REC, as they're able to, to offset the ratepayer impact of the revenue cap that the consumers feel.

So it's innovative in concept. It's based on my interpretation of the statute. But I think it's doable, because, to me, frankly, it comports with my view of the statute as written, legislative intent, and also benefits consumers. So I don't see why -- again, I'm not the policy maker, but I can see attractiveness in tough economic times of adopting that point of view.

With respect to your comment on supporting distributed solar, I firmly support it on the right hand of the slide. That's what the rebates are intended to do. Again, the percentage is not fixed. It could be more than that number.

But again, I encourage and want to facilitate distributed generation, but by virtue of the fact of our net metering rule, again, recognized as one of the best in the nation, combined with federal investment tax credits, I'm not willing to give a full, you know, purchase price of an array. I think it's a stimulus to

encourage deployment and adoption of distributed generation. And if it's appropriate, consumers will move to that, because it benefits them in the long run, and it also benefits the general body of ratepayers to the extent that if there is widespread adoption, as advocated by the Navigant report, then ultimately the ratepayers should see some form of relief in transmission and distribution costs on a long-term basis.

Just two more quick comments in terms of the incentive of the standard offer contract in attracting investment. The incentive itself is inherent in the pricing of those respective standard offer contracts that are sufficient to attract investment, so I don't see that being a barrier. Certainly if you have a long-term contract, you know, you might be able to get a better rate of return somewhere else in a different state. But I still think Florida will be an attractive place to invest if we do this right.

And finally, with respect to the revenue cap, again, economic times are what they are. We need to be equally cognizant of meeting the stated RPS targets, but consideration of the cost. And, you know, the revenue cap again might be flexible. You could establish a floor that would never go below that, which ensures that

long-term, stable revenue stream necessary to attract investment, and in better economic times, maybe on an annual basis you could increase the cap.

Again, I like flexibility in a system. I don't want to be bound, but again, I want to do the right things and try and move forward and advance not only the legislative intent of moving forward with an RPS, but the Governor's vision of doing so also for the benefit of the State of Florida and our environment.

CHAIRMAN CARTER: Thank you.

MR. JACOBS: Thank you, Mr. Chairman.

CHAIRMAN CARTER: You're recognized. Please state your name for the record, please. Push the button. There you go.

MR. SUTTON: Thomas Sutton, Sunshine State Solar Power. I echo the sentiments of everyone else, that this is a workable framework, and we appreciate the effort of Nathan.

I think, as Commissioner Carter indicated, though, that the devil is in the details. And given that this is an eleventh-hour change, when are those details going to be worked out, and who will be working them out?

But sitting here certainly and hearing what some others have said, you know, it would be very

concerning to me to have a single box or to have multiple boxes without hard allocations to them. I had planned on commenting earlier, you know, about the draft proposal that had been in front us, and I think it's clear that a lot of people focused on cost. And there are instances where that's rightly so, but each investment has two sides to an equation. There's costs and benefits, and I think the reason that wind and solar and other technologies have carve-outs is because they provide benefits that aren't captured in a dollar per kW or an LCOE comparison. And to have one bucket and lump everything in and find out that we choose just biomass or choose whatever is the smallest cost I think is a disservice, and it doesn't recognize those valves. So when we get to the details and sit down and talk about that, I think we need to consider those points.

CHAIRMAN CARTER: Thank you. Commissioner Skop.

COMMISSIONER SKOP: Thank you, Mr. Chairman. Just in response to Mr. Sutton, thank you for your comments. Again, the devil is in the details, and again, I didn't propose by any means that this should be a substitute for the staff draft rule in its current form, just as an alternative. But again, equally, I would inspire staff that the concepts that I did present

could be readily reduced to a draft rule should staff be willing to do. And again, we're in a very tight lead time, but again, I think at least from what I see in the staff proposal, it just says that, you know, 25 percent of the money is going to Tier 1 and 75 percent of the money is going to Tier 2, or vice versa. I'm a little dyslexic. I don't have it in front of me at the moment. But that just is a slice of a pie, where it's a free-for-all. And again, that could just tie things up in litigation for years, or protests or what have you.

And again, what I'm trying to do is listen to each of the respective best ideas from each of the respective stakeholders that have varying competing interests and synthesize that into something that's workable, that makes everyone marginally happy so we can move forward and attract that investment and stimulate our economy, and move forward with meeting the legislative goals and the Governor's goals.

CHAIRMAN CARTER: Thank you, Commissioner. We have -- let me just say this before we go further. We were scheduled for 4:30, and I think everybody got the calendar, and it was noticed. The meeting was noticed and all like that. We'll extend briefly, but I did want to give you guys an opportunity for questions before we head out.

I know that my colleagues may have some more questions, but what I was going to do is at least extend, Commissioners, for maybe ten more minutes and get some further comments on that. But as I said, we did have the meeting noticed for 4:30. We're already beyond that. But out of -- my grandma taught me good manners, so I will extend it for an additional ten minutes, because there are some people that had not spoken that did want to speak.

So let's do this. We'll have the gentleman in the dynamic -- I started to say goldenrod shirt, but it's actually yellow. And then we'll go back like a ping-pong ball to my left, to this gentleman here, and Mr. -- I'm drawing a blank. Wait till you get to be 56. Mr. Dobson, we'll come to you next.

You're recognized, sir.

MR. BESSETTE: Thank you, Mr. Chairman. My name is David Bessette, and I am the president of the Florida Solar Industry Association and a solar contractor that has been installing solar in the State of Florida for 30 years.

And I do want to give credit to the solar industry for building the solar industry to this point, and we really are looking forward to, you know, the RPS as it will come out. And I do thank Mr. Skop for the

plan that he has come up with. We do support it.

I just wanted to make the comment that in all the programs that I've seen so far, the solar thermal has basically taken a back seat. It seems like everyone is recognizing solar is PV, photovoltaics. The most cost-effective solar that's available on the market today is solar thermal. And I can say that because there's thousands of people that I put solar on, and I know it's about one-third the cost of a solar PV array. Not even the folks from Navigant alluded to -- solar thermal could have been included, but they did not do that. Mr. Ballinger in his report alluded to the use of solar thermal, which would have brought his cost down significantly.

So the overall cost, when we're looking at cost-effectiveness, I would just urge the Commissioners to incorporate solar thermal into whatever program is adopted or the draft rule. I think it would only be -- it would show improved financial responsibility for you all to include it.

Also, the solar industry is looking forward -- I think Governor Crist also was looking at the RPS as creation -- I was thinking, and maybe I'm reading it into it, but also creation of jobs. You get much more creation of jobs -- there will be a lot more jobs

created when you implement distributed generation throughout the state, installing systems on roofs, on homeowners' roofs, small business roofs, and commercial roofs rather than going to very large solar farms. And I think even Mr. Reedy and others would agree that the land is valuable. We have to go on rooftops.

And that's all I really have to say, and I just appreciate your time. Thank you very much.

CHAIRMAN CARTER: Thank you for your courtesy. Yes, sir. You're recognized, sir.

MR. SINCLAIR: Thanks. My name is Mark Sinclair. I work for a nonprofit called the Clean Energy Group, which works with many states in the implementation challenges that they face with their RPS programs.

I think that Commissioner Skop's standard offer approach has a great deal of merit and should be seriously considered because of the predictability it provides for financing of renewables.

I have one observation about the proposal. Again, it's fairly sketchy, so my concern may be misplaced, but I think it would be important for a legal review of one issue, and that is the concept that you can sell the attributes from this program out of state to offset ratepayer impact. I haven't looked at your

statute closely, but if this isn't going to be a mandatory renewable portfolio standard and there's a standard contract, I'm assuming you will be purchasing energy capacity and the attributes. And if that's so and it's meeting a mandatory goal in Florida, I'm not sure you're going to be able to readily sell those attributes out of the state without a double counting problem. I think that should just be looked at closely. And you may have looked at this, so you've got a great answer, but that was the one red flag that occurred to me.

The other issue I just wanted to address is the issue of the aggressiveness of eventual targets and the potential rate impacts. It's obvious to me that the stakeholders and the Commissioners are rightfully concerned about the potential cost impacts of adopting a serious RPS program. I want to point out that there has been -- a lot of states have had this concern. And recent analysis by Lawrence Berkeley National Lab, who my organization works with closely on RPS issues, has indicated that the expected bounds of rate impacts from state RPS laws are really going to be modest. I brought some comments and some slides, which I won't bother you with, but the studies are reflected in those comments. You can get links to the -- the links are there for the

studies.

Let me just throw out two findings. One of the studies looked at 30 distinct cost impact analyses completed since 1998 through 2007 and looked at 18 RPS states. The key findings showed that projected rate impacts of those RPS laws -- and they're all very different -- are generally and relatively modest. In fact, 70 percent of the studies predict base case retail electricity rate increases of no greater than 1 percent in any of the years, even when the RPS policy reaches its peak percentage targets. In six of those state studies, electricity consumers are expected to experience cost savings as a result of the RPS policy. Now, those are estimates, so it's looking in a crystal ball.

There is now, however, in 2008 a study by Lawrence Berkeley National Lab that confirms that the rate impacts of state RPS policies have been modest to date. Though the results vary across states, in most cases, the rate increases so far are estimated at less than 1 percent in 2007, and those rate impacts are probably biased upwards due to the use of short-term REC prices to assess costs.

And then this study also found, Lawrence Berkeley National Lab, which is an objective analysis

group, that in a number of states, there's growing evidence that energy contracted, renewable energy contracted in recent years has been priced competitively with conventional sources of generation. In fact, in California, the majority of the renewables bought under contract by the state utilities since 2002 have been signed at prices that are below the market price referent, which is new gas-fired generation.

So I think you should be concerned about cost impacts, but not overly so, and you should set an aggressive target that says that Florida is open for renewable energy business.

And with that, I'll close. Thanks for your time.

CHAIRMAN CARTER: Thank you. Let me do this. Commissioners, it just dawned on me that there were a couple of people who had signed up that didn't get a chance to speak. Jim Dean from the Florida Pulp and Paper Association, we'll come back to you.

MR. DEAN: Thank you very much. I'm Jim Dean representing the Florida Pulp and Paper Association. As you know, we've been participating in this hearing process for about six months. We came prepared to comment on the staff's and Navigant's work. And I guess while I'm intrigued by the proposal, I was wondering,

what would be the process for us to kind of look at the devil in the details, as Commissioner Skop referred, given this time period? Is there going to be a written proposal forthcoming and an opportunity to comment? If you could maybe give me some direction on how I can get with my clients and --

CHAIRMAN CARTER: We'll make it part of the record, and that will be available. I'll speak to that in a moment. I'm trying to get you guys that were in here -- I mean, we've already extended, but I'm still trying to get everyone here to be heard. But the record will be available. I appreciate our court reporter hanging in here. And I have not given her a break. I've given all you guys a break, but I have not given her a break yet.

Commissioner Skop.

COMMISSIONER SKOP: Mr. Chair, I'll make this really quick. With respect to the questions just presented, certainly I think I would welcome, as well as I think our staff would welcome comments on anything that people would have on what was presented. If they have ideas on what the numbers should be, certainly I think we would be open to hearing those. As far as the review process, again, we're in a tight time frame.

And just quickly to the previous comment about

the double counting of the RECs, again, my interpretation of the statute would be that the legislative intent is for the economic investment and the generation Florida, the energy component being the driving factor of compliance.

So in my view, that would not be double counting. The REC would be in is virgin state and could be sold theoretically out of state, either a compliance or a voluntary form, similar to what's done nationally now.

But to me at least, this was an innovative approach and interpretation which favors the ratepayer and makes this more cost-effective for the consumers. Even if it wasn't done, again, it would still be a valid approach. I'm just looking to make it as cost-effective as possible.

And in parallel to that, one of the comments that we've heard from one of the utilities is the notion of buying out-of-state RECs to comply with the in-state requirement, and there is no way, absolutely, that I'm in support of that, and I could not ask consumers in good faith to reach into their pockets and buy an out-of-state REC, which is thin air, to the benefit of the provider of the REC. It just does not make good policy or economic sense to me in these hard economic

times.

Thank you.

CHAIRMAN CARTER: Thank you. George Carvros. George?

MR. CAVROS: Yes, Commissioner. George Cavros on behalf of the Southern Alliance for Clean Energy. I just wanted to thank the staff for their outreach to the stakeholders during the RPS process and to Navigant for producing the study, and also to Commissioner Skop for his thoughtful, well thought out plan.

I basically just want to -- we want to urge the Commission to protect the interests of ratepayers by adopting a 20 percent target by 2020, by diversifying the portfolio with assets that aren't subject to fuel price shocks, for instance, solar energy. And in the instance of biomass, you certainly have a stable fuel stock. In that respect, you insulate customers from the massive price shocks and price fluctuations in the prices that they've been experiencing. And by bringing more renewables into the Florida energy mix, you create more certainty for consumers, not less, and you provide more relief for consumers, not less.

The Navigant report demonstrates that Florida has the resource potential to meet the Governor's call for 20 percent renewables by 2020. We think it's an

important goal. It shows that Florida is open for business. And it's important to gain economies of scale, to jump-start the renewable energy industry here in Florida. And it's often better to have a stretch goal of 20 percent by 2020. That will definitely incent that kind of investment in the state, rather than taking baby steps and being really constrained at the beginning, which will choke off any kind of meaningful investment at the beginning.

And also, the RPS needed to achieve the 20 percent renewable energy target by 2020 can be achieved at a modest cost. Based on our analysis of Navigant's report, the rate impact of a 20 percent by 2020 RPS would be about $3.50 per month for a typical household using 1,000 kilowatts of electricity.

And it's important to consider that rate impact not in a vacuum, but in the context of previous rate impacts and also ongoing rate impacts. And I won't dwell on those. Suffice it to say, they've been very significant and will continue to be significant in the future, and those are happening because of fuel price spikes and also spiking capital construction costs for new nuclear plants.

I would just kind of echo what Mr. Reedy said earlier. You can place ratepayers on -- there's two

trends. Conventional energy, because of the commodities that are involved in constructing new plants and the price fuel shocks, are trending upwards. Renewables are trending downwards. And this Commission has a clear choice on which path you want to put ratepayers, on a trend of upward costs or a trend of downward costs. And we think by being ambitious and putting out a strong RPS, you will be protecting the ratepayers of Florida.

And thanks so much.

CHAIRMAN CARTER: Thank you, George. Dell Jones.

MR. JONES: I'll defer. Thank you.

CHAIRMAN CARTER: Thank you. David, David Bessette. You already spoke, didn't you? Thank you.

Okay. Let me go back to my list. Wayne. Wayne, you're my man. Go ahead.

MR. WALLACE: Thank you, Chairman. My name is Wayne Wallace. I'm representing the Florida Alliance for Renewable Energy today. And also I'm a solar contractor and distributor here in Florida, and I, like David Bessette, have installed thousands of solar water heaters and numerous solar electric systems, and we're very grateful to be a part of the development of renewable energy in these workshops, so thank you.

We've heard a lot of good things here today,

and as I study some of these policy mechanisms myself and read as much as we possibly can to see what everyone else is doing, you know, instead of trying to reinvent the wheel, I think that, well, here we have the Governor that has ordered more renewable energy, we have ratepayers in Florida -- I myself am a ratepayer. Many, many of our constituents and customers and businesses that we work with, everybody wants renewable energy. Most people do.

So how do we go about that? Well, it seems like if we could just simply find the least cost policy mechanism that puts forth the most renewable energy, it would kind of be that simple. Well, we do have 45 countries that have found that policy mechanism. And I did see the presentation over here from one of your staffers on the feed-in tariff, and we also see that Gainesville is supporting the feed-in tariff policy, we have Hawaii that's supporting it, we have Los Angeles, the City of Los Angeles, the California Energy Commission, the United Kingdom, Switzerland.

So when we heard Mr. Karnas say that here we've had all this renewable energy installed in Germany, gigawatts of energy just within the last 12 months for about $2.50 per ratepayer, it seems like they're on to something with some low cost policy

mechanism, and also, they put forth an advanced, a tremendous amount of renewable energy, not only through PV, but bio and methane and waste heat. You know, you name it, Germany has done it. So I think they're like a poster child for the rest of the world to learn from, to see how to go about advancing renewable energy for the lowest cost.

So I have some comments here. I would like to pass this over to you, if I may.

CHAIRMAN CARTER: That would be fine. Staff.

MR. WALLACE: And I also am a ratepayer for one of the investor-owned utilities. I only have four of these, so thank you.

CHAIRMAN CARTER: You don't mind wrapping it up, do you, Wayne?

MR. WALLACE: Yeah, I will. I'll just close with this comment.

I read in the paper that I'm going to be paying about $9 a month on my bill for a nuclear plant come January that's not even built. So I think, geeze, why am I paying $9 a month for a nuclear plant that's not built yet, and here in Germany they have a renewable energy program, and they're installing gigawatts of energy, specifically, a nuclear plant, 1.1 gigawatt of PV last year for $2.50 a month. So it just seems as

though we're going the wrong way.

But anyway, I wanted to comment.

CHAIRMAN CARTER: Thank you.

MR. WALLACE: Thank you.

CHAIRMAN CARTER: Gwen Rose.

MS. BROWNLESS: She was our person.

CHAIRMAN CARTER: Thank you, thank you, thank you. I want to try to be fair to everyone.

Thomas Sutton.

MR. SUTTON: I spoke.

CHAIRMAN CARTER: Thank you. All right. I'm going down my list. We're already beyond our time, but I want to make sure that the people that signed up at least got an opportunity to be heard.

Roy Ratner.

MR. RATNER: I'll pass. I agree with Wayne Wallace. Thank you.

CHAIRMAN CARTER: Okay. Mr. Dobson, you've got two minutes. You can use it from right there.

MR. DOBSON: This is only going to take 30 seconds. I really don't have much, but I do want to thank the Commission for all the work that it has done over the last, frankly, two years, because I think we started having a variety of presentations in 2007 on this issue, and for the proposal by Commissioner Skop.

I think it really takes us in the right direction.

Let me back up a little. I represent the Florida Renewable Energy Producers Association, and our members consist of a variety of large-scale renewable developers.

And I think when we first started this process, I made the comment that from outside of Florida and within Florida, in the renewable development community, the sign is always saying, "Well, Florida is closed for business." But what I'll tell you is that what we've done today sends a signal that, well, you know, we're beginning to be open for business. And there's a lot more work to do at the next couple of steps, but I just really want to thank you guys for all the work, and I look forward to continuing to work with you.

CHAIRMAN CARTER: Thank you. Commissioner Skop.

COMMISSIONER SKOP: Thank you, Mr. Chairman. Just real quick on the handout that staff just gave from FARE, something that concerns me is that the footer says, "Strictly confidential. For information purposes only." I think they've disseminated it publicly, so I think that would waive confidentiality. But that gives me some pause, so I thought I would mention it. It's on

the left-hand side.

MR. WALLACE: That's fine.

COMMISSIONER SKOP: All right. Thank you.

CHAIRMAN CARTER: That's Wayne. You know Wayne. Wayne's World, you know.

Mr. McGlothlin.

MR. McGLOTHLIN: Yes, a quick request.

CHAIRMAN CARTER: Please.

MR. McGLOTHLIN: It will be quick.

CHAIRMAN CARTER: Okay.

MR. McGLOTHLIN: Still on the table is the proposed draft rule, and the central or the most fundamental debate with respect to that is whether to have the 75-25 split or to have no split. The Navigant studied one case of 75-25 and arrived at a value for the energy from renewables that could be expected with that assumption. They did not address the other case, and the situation begs for Navigant to follow through and modify its assumptions, turn the crank, and give us the corresponding case for no allocation.

CHAIRMAN CARTER: Thank you, Mr. McGlothlin. As I said to you this morning, you are consistent. We've heard you.

Staff, I'm going to waive closing comments, so, Ms. Miller, you can kind of bring everybody in for a

landing.

Commissioners, let me apologize to you. We did go overtime, but I think we got a stimulating discussion from all of the parties, and it was important for us to hear from everyone that was here, and we did hear from everyone that was here. As they say, it wasn't pretty, but, hey, you know, a win a still a win.

MR. RUDD: Commissioner, with your permission.

CHAIRMAN CARTER: Mr. Rudd.

MR. RUDD: A lot of good points were brought up today, and Commissioner Skop's proposal definitely deserves merit. But with that, as everybody has pointed out, the devil is in the details, and staff would request, with your permission, to go ahead and proceed working on those details and provide alternative rule language to the current rule, as well as some alternative concepts, such as the one that Commissioner Skop has proposed.

CHAIRMAN CARTER: Absolutely, because I think what Commissioner Skop did was, his comments kind of flowed within the context of the rule, so that should be easy to do. That should be easy to do.

Ms. Miller.

MS. MILLER: Yes. As we stated earlier, post-workshop comments, if you have any, are due

December 8th. We need the comments to be filed in the docket file at the Clerk's office. A transcript of the workshop will be prepared and posted by December 12th. We understand the situation, but we need the comments in by the 8th.

MS. BROWNLESS: Is it possible that we could turn our comments in by the 10th, which would be a week from today, for those of us that have --

CHAIRMAN CARTER: No rest for the weary.

MR. FUTRELL: Mr. Chairman, one thing that may be helpful to the parties is, we will make every effort to try to get the audio file put up on the website, and that may be done within the next day or two, and that may assist the parties.

Again, as you have mentioned many times, we're under a strict deadline, and we will begin working very soon to meet, as Mr. Rudd summarized, the requirements to give you a work product for January 9th. So as soon as the parties can get us their comments, we'll be able to incorporate those into our thinking.

CHAIRMAN CARTER: We have to adhere to our time, because, really, we didn't even have this scheduled. We did this out of courtesy, so -- I can't be too much more courteous or we'll never get anything done.

So let me just take a moment to express our profound appreciation to our court reporter, who went without a break. We usually give a break. We went overtime, double time. But I want to thank you on behalf of my colleagues here on the Florida Public Service Commission for your going above and beyond the call of duty.

Commissioners, I think that I'm going to waive my post comments.

Ms. Miller, anything further?

MS. MILLER: Nothing further.

CHAIRMAN CARTER: Okay. With that, we are adjourned.

(Proceedings concluded at 5:05 p.m.)

CERTIFICATE OF REPORTER

STATE OF FLORIDA:

COUNTY OF LEON:

I, MARY ALLEN NEEL, Registered Professional Reporter, do hereby certify that the foregoing proceedings were taken before me at the time and place therein designated; that my shorthand notes were thereafter translated under my supervision; and the foregoing pages numbered 1 through 239 are a true and correct record of the aforesaid proceedings.

I FURTHER CERTIFY that I am not a relative, employee, attorney or counsel of any of the parties, nor relative or employee of such attorney or counsel, or financially interested in the foregoing action.

DATED THIS 12th day of December, 2008.

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