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TIME IN SESSION: 1:00 p.m. to 3:01 p.m.

BEFORE: Chair Charlotte A. Mitchell, Presiding

Commissioner ToNola D. Brown-Bland

Commissioner Lyons Gray

Commissioner Daniel G. Clodfelter

Commissioner Kimberly W. Duffley

Commissioner Jeffrey A. Hughes

IN THE MATTER OF:

Investigation of Energy Storage in North Carolina

Presentation by:

Bob Schulte, Principal, Schulte Associates, LLC

Energy Storage in Integrated Resource Plans

Volume 2

P R O C E E D I N G S

CHAIR MITCHELL: Good afternoon. Welcome. I'm Charlotte Mitchell, Chair of the Utilities Commission and with me this afternoon are Commissioners ToNola D. Brown-Bland, Lyons Gray, Daniel G. Clodfelter, Kimberly Duffley, and Jeff Hughes.

This is the second in a series of presentations pursuant to the Commission's September 4th, 2019 Order Initiating Investigation in Docket Number E-100, Sub 164 in which the Commission has initiated a series of educational presentations by experts invited to speak on energy storage related topics.

We're happy to have with us today Mr. Bob Schulte of Schulte Associates, LLC. He is an engineer and energy consultant based here in Raleigh with roots in the Midwest. Our speaker will be working from a slide deck that will be displayed on the monitors here in the hearing room and has also been posted on our website in Docket Number E-100, Sub 164.

Our court reporter is creating a transcript that will be filed in this docket and available for your review on the Commission's website. These sessions are structured for the benefit of the Commission's education and the speakers will be asked to share their expertise and answer the Commission's questions as they arise. People in the audience will not have an opportunity to ask questions. However, if you'd like to file information in this docket in response to what you hear or if you want to suggest other speakers that the Commission should consider inviting please do so by filing comments or suggestions in this docket for our consideration. If it's okay, we'd like to ask questions of the speaker as we go along. Is that okay with you, Mr. Schulte?

MR. SCHULTE: Yes, ma'am.

CHAIR MITCHELL: Okay. And so we'll be doing that.

We appreciate your being here today and preparing this material and I'd like to go ahead and turn it over to you as I know your presentation involves an introduction of who you are and the work you've been doing.

And before I turn it over to you, I'd like to just let everyone know that our next presentation in this series has been scheduled for Monday, January

13th, beginning at one o'clock.

Mr. Schulte, you may begin. Thank you.

MR. SCHULTE: Good afternoon, Chair Mitchell and Commissioners. I'm Bob Schulte. I'm pleased and honored to be here to talk to you about one of my favorite topics in my consulting practice across the United States - energy storage.

COMMISSIONER DUFFLEY: I'm not sure your mic is on.

COMMISSIONER GRAY: Pull it towards you, sir.

MR. SCHULTE: It's green. It is green. Is that better?

CHAIR MITCHELL: Can you all hear in the back of the room? Okay.

MR. SCHULTE: Here's what I'll be talking about today -- here's what I'll be talking about today, a brief overview of my firm and the background that relates to what I'll be talking about. I will introduce storage, will limit the topic some for purposes of time and focus, will talk about grid-level storage and distributed storage, talk about the drive for 100 percent clean energy in various areas of the country and how storage relates to that and doesn't so far. And finally we'll end up in time available to do a lighting round of frequently asked questions with regard to storage.

About my firm, our executive management consultants, our offices are here in Raleigh. We have a lot of years in public and private utilities or integrated resource planning types. I started as a research planning engineer at Northern States Power Company in Minneapolis. It's now called Xcel Energy doing power plant planning, coal plants, things like that. The Sherburne County, 800 MW Sherburne County coal plant near Becker, Minnesota was my baby. It's now been in service for 32 years. Where does the time go?

Also our work is in -- has the inflection of regulatory matters. Many years ago I was the boy, Vice President of Corporate Strategy and Rates for Northern States Power, so I was responsible for development of the first Integrated Resource Plan in Minnesota. After looking back over 25 years, I'm not sure I should brag about or apologize for that yet. And so we have a regulatory bent.

Later on, I was Vice President of Marketing and Customer Service responsible for rate design. And earlier than that I was Manager of Distribution Engineering/Planning Construction Operations for the Twin Cities of Minneapolis/St. Paul metropolitan area, so if you want to talk about distribution types of things and how storage relates to that, bring it. So hopefully what we'll be able to do today is to give you elements of storage that you'll be able to impress your friends and scare your enemies a little bit as the need may arise.

Some of our recent storage activities listed here, I won't do them in detail, we're currently working on project arrangements on a very large storage project in Southern California. Actually, the project in Utah using compressed-air energy storage or CAES. You'll see this from time and again. 160 MW in 26 hours of storage. This is long-duration storage. This is not batteries. Twenty-six hours.

Currently, we're doing work on the 2019 IRP for Burbank Water and Power, the municipal utility in Southern California next to Los Angeles. And it's looking at replacing or did -- it's now before the California Energy Commission, it's replacing its share in coal unit with renewables and storage. That one for Burbank is 54 MW 48 hours or 2,600 MWh.

I was reading over your comments in the Duke IRPs and I found that I'm humbly here before you as a time traveler from the future from a solar system whose IRPs are ahead of yours in some of the topics you're struggling with on storage, particularly Burbank. We've already answered in the 2019 IRP some of the issues that are being wrestled with within your -- so I've got a CAES study, later I'll show you how that relates and hopefully that will be helpful to moving your progress forward.

We're doing a market assessment for storage for an international technology company that shall go unnamed. We've done a bunch of long-duration compressed-air energy storage strategic studies for replacement of the Intermountain Power Project coal plant, 1,800 MW near Delta, Utah which is scheduled to be retired in 2025 due to California climate change law. And the question is how do you replace it? Do you do natural gas which is the option du jour or do you do it with storage and renewables instead? It's up to 1,200 MW of storage 48 hours, 50,000 -- 57,000 MW of storage in a cycle.

We were co-author of Market and Tariff Challenges to Grid Scale Electric Storage Enabling

Renewables in RTO ISO Markets. Monetizing storage for a storage owner is really difficult in ISOs RTOs and they're just beginning to realize what the issues are.

We did a Gregory County pumped hydro feasibility study for a 1,200 MW pumped storage facility, 26 hours of storage in central South Dakota. We've got a meeting on that with the developer tomorrow. And we were responsible for the due diligence on a 270 MW Iowa stored energy park installation near Des Moines years ago.

Just a little bit of perspective here. We're all very interested in batteries and you're going to see a lot of batteries in what I'm going to talk about here today. According to GTM Research, the total amount of stationary battery storage installed in the United States last year, and we led the world, the United States led the world in stationary battery storage. I'm not talking cars. I'm talking about stationary batteries. It was about 777 MWh and we're probably going to double that this year; maybe 15 - 1,600 MWh of stationary storage.

The Utah compressed-air energy storage projects that we're working on are the first phase is 4,000 MWh and an eventual 57,000 MWh. So I'm not denigrating batteries here, I'm just highlighting that. When you hear a lot about batteries, you're only at the beginning of a very large growth curve in the battery world that's coming.

About storage, so we all think of it as a process of capturing and holding energy until a later time when we need it and we can release it in a controlled manner. And it's energy, conceptually storage is all around us. It's in our batteries. It's in our car gas tank. It's in our water towers. It's in our water heaters. It's in coal. It's in nuclear fuel. It's in our bodies in terms of energy storage for us to operate every day. My personal favorite example of energy storage is a cheeseburger to get me through the day. Even electrostatic energy storage in the clouds.

An important concept I want to emphasize here today is, and I'll keep going back to it, is storage is the act of creating time diversity, that is, separating a moment of electricity production from its use. And those differences in time is important and they have value.

Our topics today we're -- things we're not going to talk about is we're not going to be talking about storage that involves storing electric energy and regenerating -- well, we're going to be talking about regenerating the stored energy as electricity, but we're not going to include thermal energy storage. So I'm not going to be talking about water heaters, for example, where the end product is hot water or cooling in commercial refrigerators and freezers or swimming pool heaters.

Also at the request of staff I'm going to limit the topics that I'm not going to be talking about storage by customers behind the meter. It's a whole other topic for a whole other day with its own complexities and it's inevitable search to go from retail out onto the wholesale market, which is a lot of the traffic that you're seeing right now. I'm not going to be talking about those. So we've got a lot to talk about other than those types of topics.

Let's talk about grid level storage first of all. There's lots of ways to store energy on the grid. There's thermal energy like water heaters. There's chemical energy like batteries or hydrogen. There's electrostatic energy like supercapacitors. There's spinning a heavy wheel on a shaft like a flywheel. Gravity is a very major one. Moving a massive object or a fluid to a height. An example is pumped hydro storage, which -- which with you are familiar already. And there's compressed gas, so usually you're taking kinetic energy of some type like a wind machine or photovoltaics and you changing it to potential energy storage and you're bringing it back in kinetic energy to rotate something.

The bulk storage on the electric grid is typically located on the transmission system. It often has multiple megawatts of capacity. It's ability to store and generate for multiple hours. And I'm going to draw a clear vision here between long-duration storage which some things like the pumped hydro and the compressed air, which I for purposes of discussion is longer than eight to 10 hours, and as opposed to shorter-duration storage where batteries dominate, one half hour or one hour. Four-hour batteries are typical now in the utility industry. Sometimes you see six-hours batteries, but four hours is a pretty standard longest.

The dispatch authority varies, in fact, it's an item of conversation and debate. In the organized markets it's dispatched by the RTO or the ISO. And the debate is going -- is ongoing, that is, who is responsible for the state of charge? Is the ISO supposed to keep track of how much is left in the storage? Or is the owner supposed to keep track of what's in the storage and thus -- and they bid it that way. So that's a debate at FERC and elsewhere. The dispatch authority in other areas say here in North Carolina is the local Balancing Authority, the local utility.

Here's a graph -- a popular graph by Energy Information Administration showing the various types of storage related to their capacity on the horizontal axis and their duration of output and their discharge time on the vertical axis. And in the top right corner is the two classic long-duration options; pumped storage hydro and compressed air.

I'm only going to talk about pumped storage -- you're familiar with pumped hydro, but I'm going to talk about it a little bit here today, because its use elsewhere in the country is starting to change. Originally installed mainly to support the nuclear plants and giving them load at night to keep the nuclear plants from having to cycle. And so the nuclear plants can see a steady load all during the day.

Now in places where the nuclear plants are starting to retire, the operation of existing pumped hydro facilities, which are still super useful facilities, are changing. They're changing to store the renewables, not the nuclear. So they're storing at different times of day than they used to. Okay. So I'm going to touch on that just so as an indication of what the future holds for even existing pumped storage projects.

I'm going to talk about pumped hydro and compressed air, and then in the big blue circle, the batteries here. I'm not going to talk about some of the other more incidental storage technologies. We're going to talk mainly about those big three. I'm going to talk about lithium-ion batteries. There are other battery technologies. There's lead acid like my old DieHard battery in my Ford Mustang that used to start the whole dormitory parking lot when it was three below in Brookings, South Dakota. Everybody knew my DieHard would start, and then we would jump-start everyone else's car from there. So that was lead-acid. Okay. It was very commonly used and still used in the utilities and substations for -- as backup to their controls and relays and things like that.

But mainly now it's lithium-ion and there are other technologies that are out there and may -- coming like flow batteries that you hear about. But the main leader in the clubhouse right here and now is lithium-ion. So I'm not going to talk much about battery chemistries. I'm going to talk about lithium-ion, because that's where the activity is.

Most of the activity there in lithium-ion is in cobalt and trying to minimize the amount of cobalt that's in the lithium-ion batteries, because 60 percent of our cobalt comes from the democratic country of Kongo and probably not a good place to depend on a lot politically for a large portion of your energy supply.

Talk about a lot about grid stability concerns and there's a lot of words in the Commission's comments on the Duke Progress and Carolinas IRPs with regard to the topic of ancillary services.

Now, I'm a little surprised to see ancillary services talked about in an IRP. I'm from a vertically integrated region of the country up in the upper Midwest and much as you are here. And ancillary services really hasn't been traditionally a topic in

IRPS. The IRPs you're dealing with providing enough energy and capacity in bulk for the future, whereas, ancillary services relates to the people in the operating center that hour-by-hour, day-by-day are balancing the load and the generation that happens.

So typically these are really two different departments in a utility, and we leave those operation people; they do their magic, okay, balancing those things minute-by-minute. All right. So the balance here is load and generation. If the load is too high relative to generation, the system, that is the frequency, slows down. All the generators in a micro sense go vrrrrrrrrrr (sounds like an engine) and they slow down just a little bit and the frequency, that 60 cycles -- 60 cycles per second, that's 60 Hz that's in the lights, in these outlets in your home that's determining how fast your clock runs at home and in your business that frequency lags a little bit if the load gets bigger than the generation.

So the system operator's assignment going back decades is to keep that balance happening. So whenever someone turns on a switch someplace, somewhere far away a governor on a coal unit or some other unit just opens up just a little bit. Okay.

And juices up the generation just a little bit. To again, to maintain that balance and that balance is moving around all the time, is moving up and down, and it's not perfect all the time. Its load is changing all the time, people turning things on and off all the time. For example, air conditioners cycling on and off. Okay. So this is an ongoing dance, this balance to keep the system frequency constant at that 60 Hz.

Sometimes it'll get out of range for a little while and all of the utilities will get together and they'll decide, oh, we're too far behind in the frequency, we have a frequency deficit for a while, so we're going to do a time correction, and they'll goose their generators just a little bit to speed the frequency up and it'll bring all your clocks at home and in your commercial businesses back up to where they should be in exact standard time. It feels a little big brother, doesn't it, but it's -- it's been happening quietly in the utility industry for many, many years.

So that brings up the conversation of ancillary services. Particularly now as we add more renewables, it adds more difficulty in maintaining the load and generation balance, because the renewables on the generation side themselves are variant. Clouds are going over. The wind is variant. And so there's volatility in the output of the renewables, which -- and we're trying to get more and more penetration of renewables.

So ancillary services include frequency regulation. That's the very short intermittent making adjustments to the frequency as you go along. Ramping up and down. That is when the sun goes down and the solar reduction -- the solar output reduces dramatically, then the other sources have to ramp upward to accommodate for that. Okay. They've been ramping up and down for years at the beginning of the day when people start their day or when businesses end, so utilities are used to ramping up and down, but now you add ramping requirements driven by the energy source, and particularly solar at the beginning and end of the day. That's the so-called California duck curve we'll talk about briefly.

There's operating reserves. That is utilities carry so much of their reserves that are spinning in their generating plants, they hold back, they're not all running flat out, because they all have responsibility to keep some reserves holding back spinning in case they lose a generating facility and those then held back megawatts can then cycle quickly and ramp up to pick up the difference. And then there's non-spinning reserves where it's got a 10-minute start time. And then there's black start -- black start capabilities now.

We're talking more about ancillary services today, because we're talking more about adding renewables and the volatility. So that's why and I did a word search on the Duke IRPs, each of them, there's five or seven hits on the words "ancillary services" in 280 pages, mostly talking about ancillary services in the context of the renewables are causing the need for cause for doing ancillary services.

The other item that I notice that's different from what I'm used to is apparently an interest of potentially having third parties provide ancillary services capabilities. Like if they own batteries, can they do value stacking and receive some monetization of that. So that's where the ancillary services comes from.

Now, reading those over, it occurred to me that the Burbank, for example, Water and Power IRP that I'll show you in a little bit had some answers on how to address those types of things.

Bulk storage can also provide multiple services. Just a little bit of a complex diagram from Rocky Mountain Institute, but depending on if you're a utility at the bottom here at the blue arc, it can be a distribution deferral or transmission deferral or a resource adequacy. If you're ISO and RTO, services in the green, you can get spin and non-spin reserve frequency regulation, those ancillary services I talk about. And if you're on the customer side in orange, you can use it for backup power, a demand charge reduction and a time of use bill management and others. So depending on who you are, the bulk storage could provide different services.

Just to provide a contrast, I did a pros and cons table of the pumped hydro and CAES and batteries. I won't go over in detail, but the pumped hydro and CAES's benefit -- have benefits. So their pros are long duration. They have economies of scale. They're lower cost per unit of kilowatt hour stored. And they have a long lifetime. And the flip side, batteries have little environmental site impact. You can put them nearly anywhere. They're flexible and modular. They're very fast rampers up and down. No greenhouse gas emissions. No moving parts. Little higher in cost per kilowatt hour storage, we'll show in a moment.

Capital cost. Let's create -- let's compare the long-duration storage alternatives with batteries for example. And we all know pumped hydro has a reputation like a cost per kilowatt. This is installed cost, not capital cost on the right-hand column of this chart. For the Gregory County project, it would be $3,000 a kW for a 1,200 MW unit.

The studies of CAES that we're doing, compressed-air storage, this is 26 to 48 hours of storage; still have significant capital cost.

Now, the batteries at the bottom, lithium-ion from the Burbank IRP is four hour, one hour, or half hour batteries from top to bottom, $580 kW, 381 to 231. These are including the declines in battery cost that are happening now. These are mid-2025 types of costs. And so I look at this and go wow, why would anybody do a long-duration storage. Look how expensive they are compared to the batteries. Okay. But that's not the whole story.

If you add the right-hand side of the chart that's on your paper version here and you look at the duration, the pumped hydro can have 26 hours in this example, compressed air can be 28 to 48 hours compared to the shorter-durations of batteries. So if you look at dollars, capital cost per-kilowatt-hour stored, the answer flips the other direction. That is the long-duration storage technologies have the cost advantage. Okay. That's why there's interest in them. That's why we go through the problem of environmental concerns on some of them, and versus the batteries that come out longer.

Now, also the nominal lifetime of these technologies are different. I mean, this is -- I'm in the fine print now when you look at batteries, for example, and I'm a big proponent of batteries, but I'm also in favor of let's do batteries eyes wide open with the application. All right. Okay.

The nominal lifetime of some of these long-duration projects, storage projects, are 30 to 50 years and the published lifetime for batteries is 15 to 20. Okay. So right there you're looking at and comparing things, you're going to have to replace the batteries in the lifetime of doing the long-term storage. But it gets even more so; you find that when you start using the batteries, the cells have to be replaced during their lifetime. In the Burbank IRP we're replacing half the cells every five years, which means you're buying twice the batteries during the lifetime than the initial installation cost implies. And then also if you try them for long -- try to use them for long duration, which some press articles recently have done, okay -- oh, you can replace -- you can replace peaker units with four-hour batteries. No, you can't. Okay. They're not a one-for-one. Okay. If you use battery -- batteries, four-hour batteries, are lower reliability than a peaker unit -- a megawatt of peaker unit, so you may need twice the number of batteries, four-hour batteries, to be equal in reliability in resource adequacy and peak demand adequacy than a peaker plant. So again, we're going to be doing a lot of batteries, but to lose them -- let's use them for the right application and in the right way to get the lowest cost for customers.

Grid storage and distributed storage are complimentary. People keep saying oh, which is better, distributed storage? Should we do distributed storage or should we do grid-level storage? And the answer to that is they're not mutually exclusive. Okay. Both of them could help result in lower cost for customers and better reliability. So for purposes of reliability, they can and should be used together.

I'm going to talk briefly about pumped storage. You know about pumped storage already. You already have it. But in the context of how the changes are happening now with renewables in other portions of the country. And this is the simple diagram pumped storage, get us all on the same base. It involves taking water from a lower level, you pump it up a hill to a higher reservoir, and then later you wait, and then you bring it back, let gravity bring it back down, you run it through the generator to regenerate the energy. Pretty familiar with that.

We're working on a project in central South Dakota called Gregory County. It's on the Missouri River. And this is a graph of a wind speed map of the United States. The bright colors are high wind speeds and the lighter colors are low wind speeds. And the blue dots are -- on this map are where all the other pumped -- existing pumped storage projects are now.

Pop quiz. What were the existing pumped storage projects not designed to do? Well, they weren't designed to integrate renewable energy originally. They were -- originally, most of them were designed to accommodate the nuclear plants and giving them load at night and keep the nuclear plants running originally.

So this is an example of using bulk storage for renewables. And here's an artist's conception of what that might look like. It's an existing lake on the Missouri River called Lake Francis Case behind the existing dam and you build a reservoir up on the bluffs and you surround it with wind machines. I'm from central South Dakota. I'm a prairie boy. There's plenty of room there to put wind machines right up smack against that reservoir.

Here's where the fun happens. This chart -- this chart, the green is the hourly, a year's worth of megawatt readings for a South Dakota wind farm in central South Dakota. Okay. And you squint your eyes a little bit you see it's a little thready in the summer and a little thicker in the spring and the fall. And if you take those hourly values and you put them in order of their magnitude you get what the resource planner calls an output duration curve. Okay. And what this tells you is the probability that that wind farm is going to be at any particular output at any particular time, and how long.

And way on the right here where I'm at one per unit, the peak of the farm, it's not at that peak very often. The peak output of the installed megawatts of wind farm don't happen very often. That eats up transmission cost and capacity. You build for it. Okay. But it doesn't if you store it instead, okay, and you use the storage to use it later. So for those who like output curve, duration curves, and who don't -- who doesn't, you notice that most of the energy of a wind farm is in the lower half of its output curve and the lower half of its wind speeds. In this case 73 percent is in the lower half. And so our target is to store the upper part of the curve and not build transmission for it and use the storage instead.

Long-duration storage, however you do it, can integrate more renewables than say a conventional combined cycle gas turbine for the same amount of outlet transmission, and we're using this concept in the upper Midwest and we're using it in Utah.

Here's an example. Suppose you have a limited amount of outlet transmission, and you always do. Your outlet transmission is always limited. That's the dotted line across here. And you put so much wind capacity on that as outlet to use that transmission to get to load, that's the green bar.

Now, typically what's done to integrate that is you use a combined-cycle gas turbine, a simple-cycle gas turbine, or even a battery of a similar amount of capacity to integrate that amount of wind. Okay. When the wind blows, the combined-cycle unit is silent. When the wind is not blowing and customers need it, the combined cycle operates. This is called in MISO where I'm from net-zero configuration. There are generating units in the upper Midwest that have operating agreements with the wind farms on the same transmission lines where they will not operate at the same time. They're sharing the transmission outlet. Okay. So that's what we're used to thinking about when we think about using batteries or just about anything else to integrate renewables. Doing it with long-duration storage is really different. You might have the same amount of generation in your long-duration storage or you can put a lot more wind machines in this example, a lot more wind capacity on that transmission line. In fact in the studies that we're doing for various clients we're super-sizing the wind capacity compared to what the outlet transmission can handle.

And how do we do that? That sounds kind of nuts. Well, when the wind gets too uppity during that narrower part of their output curve, okay, a lot of the time you pump and you store that excess and you bring her back later. Okay. So this is -- this is storage as a transmission asset. Don't be confused that it's got a generator on it. Okay. It's actual application is a transmission asset, because the storage is protecting the transmission line from overload and it's avoiding the need to build more transmission to build to the peak of the installed capacity of the wind. Storage as a transmission asset.

So bottom line, finishing up on this CAES study results, 2,400 MW of high capacity wind, 1,200 MW of outlet transmission, and it costs less than a combined-cycle alternative and it produces more energy in that it's a baseload near renewable generation resource, the combination of the two.

You see other -- stepping away from pumped storage, there are other ways to use heavy things. And so in the news this week I noticed a scholarly paper on this technology, and that is in the search for cheaper, longer energy storage, mountain gravity could eventually top lithium-ion. Okay. Let's consider this for a little bit.

The concept goes like this. You build 50 ski lifts up and down a mountain. Fifty ski lifts is the example. Each one has a container that can carry 2,000 pounds of sand. Okay. The moral equivalent of a Cadillac Escalade. And the stored energy then you -- when electricity is cheap and plentiful, then you run all the ski lifts and you run all the sand, all the Escalades up the hill to the top of the mountain. Okay. Now, you've got all that weight at the top of the mountain, right? And so when you need it, then you reverse the process and you've got generators on the ski lifts at the top and you lower the buckets of sand all the way back down the mountain or the Escalades, all 50 of them. And if you do that, you can get 5 MW of stored energy out of it.

With all respect I don't know as we're going to see 50 ski lifts up and down the Carolina -- the mountains in Carolina to get 5 MW but watch yourself when people have scholarly well-meaning approaches to long-term storage.

Compressed-air energy storage and I say

this, I don't know if there's a lot of -- there might be some locations you could do compressed air in North Carolina, but I'm doing this just to illustrate another application of storage with regard to renewables. And what CAES is is you take electricity when it's plentiful, say when the wind is over producing and solar is over producing, and you run that through an electric motor and it compresses air and the compressed air is then put into an underground storage cavern. It can be brined out of salt. It can be cut out of stone. It can be an empty mine, an abandoned mine shaft for example. It can be an aquifer that's filled with water and create a bubble in it. And then you store it there until later on when the electricity is needed. Then you bring the compressed air back up. You add some natural gas and you regenerate that through a turbo expander to get it back on the -- back on the grid.

This is the subject of a article in the *Power Engineering* magazine about our activities. The cover story in fact not too long ago. And this is an application for -- of the Utah CAES project. A use of storage to replace an existing coal-fired power plant that's about to be retired.

And it goes like this. It starts with 3,000 MW wind field in Wyoming. Okay. And this could be solar, but this is what we're using an example. This could be the Range Wind Farm in southeastern Wyoming. It could be the Anschutz Wind Farm, Chokecherry, Sierra Madre, 3,000 MW in Wyoming. And then it's taken by high-voltage direct current line which is proposed, it could be the Duke, the ATC-Zephyr line that's been proposed, the partnership that Duke has with ATC Transmission, or it could be the Anschutz TransWest Express Line from Wyoming to Delta, Utah, and there at Delta, Utah is the 1,800 MW coal unit that's due to be replaced. The option du jour is to put a gas plant there. The alternative option that we've been working on is to do storage with those renewables instead.

The red line is existing. The HVDC line to Southern California that now takes the baseload upward to that coal plant to Los Angeles, my client Burbank, Glendale, Riverside, Anaheim, the Southern California Municipal Utilities who have to be out of their deal with the coal plant by 2027 due to California climate change law, and they decided to move it up to 2025. So what to do to replace -- to replace that coal plant?

We've did a -- we've done a number of studies using AVB's grid view, Dr. Jing Jiang Zhu, my colleague at NC State campus did the studies for Burbank and the Western Electricity Coordinating Council on this option.

Here's how this one goes and this is kind of fun. This is -- at the top these green lines is what 3,000 MW of Wyoming wind looks like over a year. And down way down at the bottom there's 300 MW in the blue and the red are 300 MW of existing wind there at Delta that needs to be accommodated. And using the storage, we're going to pack that 3,300 MW of wind down to a 2,400 MW DC line to Southern California where the duck curve awaits. So in our modeling it's a mashup of hourly output of wind from Wyoming and Utah as a supply mashed up with the duck curve hour-by-hour requirements in Southern California. And the way we do that is with the 1,200 MW of CAES using that peak flipping chart that I showed you earlier. So that's the basis of what we're doing.

I showed this chart at a financial gathering a couple of months ago and people asked me is that really what the CAES storage units look like and I had to admit that no, those are my brother Gale Vanderworth's soybean bins in South Dakota. But the concept is the same, right? You take a commodity when it isn't worth much like brother Gale harvests his soybeans when everybody is harvesting their soybeans and the market price is like zip relatively speaking. And so over the years, his 35 years on the farm he's built these bins and he puts his soybeans in there and he waits. Okay. He waits until everybody else's bins are empty. He waits until the harvest is over and he brings it back when the price is higher. Okay. And that price differential pays for the storage and makes it worthwhile to do. So your common sense applies.

So the CAES study results showed that a storage of wind combination would deliver more annual energy than the Legacy 1,800 MW coal plant, be dramatically reduced greenhouse gas emissions, and it would cost less than the natural gas-fired combined-cycle addition and even the existing IPP coal plants, so put aside the idea that storage and renewables is going to cost us a bunch more money. The days are here the cost of renewables and storage and stuff is these things are doable and cost effectively as well.

CAES study Burbank Water and Power --

COMMISSIONER CLODFELTER: Mr. Schulte, before you go to the Burbank study, a technology question. Is it feasible to do any sort of above-ground structures to store compressed air or -- I mean, we are not a state that's very rich in below-ground opportunities, so is that technology really available to us?

MR. SCHULTE: The answer -- Commissioner, the answer to your question is, yes, it's possible to build metal tanks, for example, to store it. The cost of -- the cost of the metal tanks is pretty high compared to the alternative, but yeah. If you've got some abandoned mines, for example, that's an option, but otherwise, no.

I'm more showing you this as the long-duration storage options that are being used as alternatives to coal plants elsewhere rather than necessarily an option for North Carolina.

COMMISSIONER CLODFELTER: Actually it just occurred to me we do have an awful lot of abandoned gold mines in Charlotte.

MR. SCHULTE: Something to be looked at. The Burbank Water and Power Integrated Resource Plan strikes more closely to some of the issues that you are facing here in your process. My firm, Schulte Associates, was the coordinator of this plan. Burbank is a modest size municipal utility in Southern California. They are 320 MW peak demand. They're Located in the Los Angeles Department of Water and Power balancing area. They're operated like a vertically integrated utility. Okay. They're not CAISO. They're not the ISO. They're -- so they look like -- they look like more like North Carolina than they do PJM for example. They're one of the 16 largest municipal utilities in California that had to develop and submit an IRP to the California Energy Commission for the first time in 2019.

The State of California is getting their arms around the municipal utilities and their Integrated Resource Planning processes. And they did that with the investor owns long ago. The California Public Utilities Commission has that responsibility, but the Energy Commission now is promulgating IRP activities with the utilities. And the highlights are proposing to share -- replace their share in the coal unit to retire in '25 with the combinations of renewables and energy storage. It could be CAES or it could be batteries as you'll see in a moment. Again, it's a transition from coal to energy efficiency, renewables, and storage.

Now, this next chart is a little complicated. The left-hand side is just showing you we looked at maybe 26 or 30 different scenarios of different combinations to replace the coal unit. But on the right-hand side were the leading three least-cost options and those turned out to be combinations of Wyoming wind, Utah solar, and CAES, or Wyoming wind, Utah solar, and four-hour batteries, or Wyoming wind, Utah solar, and internal combustion engines like Wärtsiläs. Okay. Really fast ramping. Super- efficient modern. Looks like a diesel. Okay.

My dad was the head of the utility in South Dakota. I grew up in a diesel plant. Okay. These look very familiar. Okay. But these all came out -- came out really, really similar.

Some results were a 68 percent RPS by the end of the planning period. Okay. We were -- by California law we were shooting about 60 percent by 2030, so this is a little different than your situation. And we found that an RPS of 67 to 70 percent can be done with rate increases at or less than the general rate of inflation. So Californians, we got pressed to do this as an assumption and as it comes out cost wise, liability wise this can be done.

Now, going the rest of the way as I'll talk in a little bit, to 100 percent is a different matter. Right. Sixty to 70 percent this can be done. And 87 percent greenhouse gas emissions reduction mainly from the retirement of the IPP coal plant at the beginning. And this emissions reduction is similar throughout all of our scenarios of whatever we use to replace it because we're using the same amount of renewables in every one. That's where the greenhouse gas emissions come in is from the renewables.

The results for the storage and renewable, these are the lowest cost options that came out of our optimization study, A, B, and C here, and the good news was that these are present-value cost in 2019 dollars over the lifetime of the planning period. The good news was the lowest cost options were all pretty similar in cost, which gives us some steerage room, some water over the rudder in case of as we procure these things we get a bump in the road then we can change something and we're still going to be pretty much -- but A was CAES and wind and solar, and B was for our batteries and wind and solar, and C was internal combustion engines and wind and solar.

Intermittency and then I'm kind of circling the issues that you've got in your Duke IRPs here, but intermittency was a big part of the discussion in the IRP conversation in Burbank. Recall we're going for 60 percent renewables. And their intermittency in the renewables driving what a portion of our resource mix needs to be.

Let's take solar as an example. On this grid the blue line is what we would expect hour-by-hour during a solar day would be the output of your solar farm. The dotted line is on a moderately cloudy day. Bumps around. Okay. The system operators have a busier day keeping that balance for the frequency between load and generation on a day like this. And then cloudy is just -- it's just more reduced.

So in our modeling, and again, this is a complicated chart. I'll tell you what's the important part to look at. This is the -- a curve of a day in I believe April and the blue line, the top one, is the customer load for the day. The yellow line is say the pattern of a solar farm. The blue-green line is the output of a wind machine on that particular -- of a wind farm on that particular day. Notice how it's bouncing around. And then down there in the brown line is the net after the solar farm and the wind is subtracted from the total load and you get what the net load is what the rest of their generators have to deal with.

And the bottom line is what the poor system operators have to deal with. That's called area control error. That is the error between their -- how well their load and their generation matches. I want to focus your attention on that bottom kind of cryptic thing there. The area control error, it's bouncing all over the place minute-by-minute. This is where the ancillary services conversation comes from. How do you smooth out that area control error so you keep your operation within National Electric Reliability Council requirements and regional requirements for keeping your system in balance? And each utility has that responsibility to keep their operation in balance.

And what we did in the Burbank IRP and with our modeling vendor is they are able to model that jiggly volatility day-by-day of the solar and wind farms and they're able to match up how much fast ramping half-hour or one-hour batteries you need to make that area control error more manageable and flatter. And so as an output of our modeling efforts we knew how much, and I'll show you how much in a little bit, we knew how much fast batteries we needed to deal with the volatility of the output of our renewables.

This is something new. I've been doing IRPs for a lot of years, I've been through a lot of models. I didn't see the model that did this before honestly speaking. And as I went around in conversations with the other 15 municipal utilities in California, they hadn't see it either. Okay. So we were -- happened to be fortunate to get a modeling vendor that had a model to be able to do that. So I'm here to testify literally that those models are out there. Okay. That can tell you how to deal -- how much batteries you need and what kind to deal with this volatility. And this isn't an intermittent type. This is frequency regulation going on here. Okay. Good application for batteries.

Also in our modeling we had -- also related to ancillary services we had the California duck curve, and I presume that you're all familiar with this, but in case for those in the audience who aren't this is a CAISO chart and it's a little complicated, but the top line in the middle is what the demand shape -- this is an hourly demand curve for California CAISO. And the top line to the middle, the blue, is what the demand looked like for decades. Okay. The load starts a little low in the morning. It's a little higher during the business day. It peaks a little bit when everyone gets home and turns on their air conditioners and gets home at night and cooks dinner, turns on TV, and then it declines again. Okay.

But now the challenge as California adds more and more solar -- has more and more solar, that solar which is non-dispatchable is starting to carve out that load curve as seen by the rest of the generation system in California. And every year they've out paced what they thought the impact would be and more and more because they've got what, maybe 13,000 MW of installed solar now, which means at the beginning of the day when the sun comes up and all of the solar starts kicking in and it's starting decreasing the -- decreasing the load observed by the system operators by the utilities, and so there's a big ramp down it's called in the morning -- the morning side of the shape -- as the sun comes up and the solar kicks in. So they're taking generation off line as fast as they can go in the morning as the sun comes up. Okay.

And then it gets to the bottom of what's called the duck curve so called because it takes on the shape of a duck. Okay. Again, my apologize -- my apologies to those who are familiar with this already. But then when the sun starts going down at the end of the day, the challenge reverses, that is, the sun is going down, the solar output starts going down, and all the non-solar generating units, all the natural gas plants primarily in California -- they don't have nukes anymore -- has to make up the difference. And they have to ramp like crazy. Okay.

They have had some 13,000 ramps in an hour or two in California. This is excitement in the control -- control rooms. Okay. And this is getting deeper and deeper as the solar gets more and more. California is at what? Maybe 30 percent, 33 percent RPS now and it's going to double over the next 10 years. Okay.

So part of the role for storage here and a lot of what you hear for four-hour battery storage is that peak in the evening is ideal if you stored -- charged up your four-hour batteries during the day, then you discharge them during that peak part of the duck head at night. Okay. And so when you hear about four-hour battery storage, that's a lot of where the interest is coming from. It's from California and the duck curve.

In the IRP for Burbank instance we had -- depending on the scenario we had various instances of four-hour batteries. We had 113 MW of four-hour batteries where we were using that to replace with renewables, replace the coal unit, and also in some other -- up to 113 MW, 50 in some other applications. But the main story that I want to highlight here today is the ancillary batteries. Every one of the scenarios showed needs because of that volatility effect of 80 to 100 MW of up to one-hour batteries. This is in a utility with a 320 MW peak. So a third of their peak demand in fast batteries to deal with volatility of renewables. Again, this is in a 60 to 70 MW RPS situation, but I'm here to say as we add renewables, there's going to be a lot of fast batteries needed just to help us with the volatility. Distributed storage moving away off --

COMMISSIONER CLODFELTER: May I ask you a question about that slide, no. 45?

MR. SCHULTE: Yes, sir.

COMMISSIONER CLODFELTER: So I'm looking at portfolio number 3 which has the RICE units at 51 MW.

MR. SCHULTE: Yes.

COMMISSIONER CLODFELTER: It also though has one of the highest needs for ancillary batteries. I would've -- I guess maybe I don't understand how the RICE units are being used in that portfolio. But I would've thought they would've reduced the number of ancillary batteries needed.

MR. SCHULTE: The internal combustion units, the ICE units --

COMMISSIONER CLODFELTER: Yes.

MR. SCHULTE: -- ramp really fast and they're really good --

COMMISSIONER CLODFELTER: Right.

MR. SCHULTE: -- they're really good at ramp --

COMMISSIONER CLODFELTER: Right.

MR. SCHULTE: -- increment decrement up and down.

COMMISSIONER CLODFELTER: Right.

MR. SCHULTE: The batteries beat them at just a raw speed of the intermittent -- inter-minute, the super fast frequency regulation types of activity. So that's how that came out is the batteries were superior to the ICE units in that portion of the application. But otherwise the ICE units were terrific rampers.

COMMISSIONER CLODFELTER: So they were being used in that portfolio for ramping and the batteries were being used for frequency regulation?

MR. SCHULTE: Yes. Primarily. Yeah. They had separate roles that ICE units were doing the ramping and the batteries were doing the frequency regulation.

COMMISSIONER CLODFELTER: Okay. Thank you.

MR. SCHULTE: Thank you for that question. A little bit about distributed storage. Let's go on the distribution side just for a moment and there's two pieces of distributed storage. There's front of the meter for a substation. Could be a substation end and a customer end. I'm not talking about behind the meter per the -- per our limit of our topics here today.

And here's just an example. Here's an electrical engineering one-line diagram of a distribution operation. The blue line is a distribution feeder to customers. This little disc here is the substation breaker to the feeder. You have the transmission system out here outside the distribution substation. You got a switch from the transmission systems. You've got a breaker and you have end with a doff the hat to my -- I'm a grandfather and to my grandson this is a Transformer here in the distribution substation.

So what you do to do storage in the substation is you might have a solar facility there at the substation. You've got their inverter and the transformer that goes to the bus work for -- in the distribution substation, and you might have some battery storage tied to that same inverter. And the reasons you might do that is so this could be utility rate based and the benefits makes it more reliable. It could be a capacity energy source. It could be transmission deferral, that is it could make the distribution substation look smaller load-wise to the transmission system. You could defer increasing the size of the distribution transformer. Okay. Again, because it makes the load on all the feeders look smaller. Okay. Because you're generating at an appropriate time. So that's one application on the substation end in front of the -- front of the meter storage.

Going to the other end literally you could have a solar installation at the customer -- at the end of the customer meter. Might be the customer's own solar. And you might have storage there, which then makes that type of installation more reliable. So it might be totally rate based. Must be a customer contribution to do this. I mean, it might be for a very particular reliability sensitive customer or environmentally sensitive customer. The reliability customer that needs higher level reliabilities and they'll pay a contribution to do that. Okay. So it protects the nonparticipating utility customer. Okay.

And so the benefits, again, are reliability particularly for a particular customer potentially. It could be a capacity energy source. It could be transmission deferral. It could help the sub defer the distribution substation installation or having to increase it. It could defer investments in the distribution feeder itself, because again, you're lowering the load as seen by the feeder from the substation, the customer.

So some conclusions for distribution is it's typically Utility asset that's rate based. It could be part of the utility's distribution or Integrated Resource Plan. I took a lot of heat from my client in Burbank when I wrote the outline for their Integrated Resource Plan and included the distribution system in it. Took a lot of heat.

What are you doing with distribution and the supply -- supply Integrated Resource Plan? I said well, your distribution department has -- is preparing for widespread distributed energy resources, getting ready to help manage those. They've got fiber communications between all of their nodes so they can help them do that. And they have set aside all of their retired distribution substation sites for future battery installations. I think they have a role in your -- in your Integrated Resource Plan. And I had to quietly smile when the California Energy Commission this year in their review gave Burbank kudos for including distribution in their resource plan. My lips didn't even move.

It can be located at the substation end or the feeder end. It could be a community-based solar storage project. That's solar at the community and that could be a community solar project or it could be at either end of it. And the potential benefits are reliability and so on I've already mentioned. Okay. I'm going to move away now from grid-level storage and distributed storage. Do we have any questions at that point before I pivot to the next topic?

The next topic is a favorite of mine. Been driven into it more or less in my practice. And the drive for 100 percent clear energy and how can storage get us there. Now, you may not have that on your plate yet, but we've got some lessons that are being learned elsewhere in this drive that can be useful I believe to this Commission and to the State.

Hundred percent clean energy goals are bandied about quite a bit. I use the term "clean energy" rather than renewable energy. I'm from a nuclear utility, right? Nuke is good, right? So a hundred percent clean energy. The goal is not 100 percent renewable or clean energy as it's usually represented, but it's to reduce greenhouse gas emissions and however else we get there. All right.

So let's just be clear on the goal.

Many states have adopted 100 percent renewable clean energy goals as shown on this table. Some of them are in law. Some of them are in order. Some of them were legislated in the past, but it had not been signed yet. And you can see, you know, this is just a current list off the line. And most of them are aimed -- other than Washington, DC, most of them are aimed to kind of the 2040 - 2050 timeframe. Okay. My client's, the City Council of Burbank, after we presented our 87 percent greenhouse gas reduction IRP 70 -- 67 - 70 percent RPS, our renewables IRP to them, they said yeah, but why can't we get to a hundred percent renewables today. Okay. So what you're about to see is part of the answer that we developed to that.

Oh, to mention clean energy goals, North Carolina also has an Executive Order that represents certain goals including reducing greenhouse gas emissions 40 percent and other positive steps in moving along that way, so it isn't that North Carolina is being left behind here.

There are 141 cities so far that have adopted 100 percent goals; Chapel Hill, Apex are in there. Bless them. Okay. And that's growing.

And corporations are adopting 100 percent clean energy goals. Google and Apple are now 100 percent "powered" -- I put that term in quotes for reasons I'll describe in a moment -- by renewable energy and more than 130 corporations have committed to 100 percent clean energy via what's called the RE100 Initiative including Anheuser-Busch, General Motors, Nike, Ikea, and others.

So at a word about a hundred percent renewable, and this is what we had to explain to the City Council of Burbank after they had a lineup of people that literally went out the door in the IRP who said here's a listing of all the cities that are going a hundred percent clean energy, why aren't we. Most entities claiming to be 100 percent renewable and I'm assuming all of you are aware of this, maybe some in the audience are or are not, most of them are doing it on the average. Okay. That is they're simply procuring a quantity of renewable energy or RECs, renewable energy credits from others, equivalent to their annual energy use. Okay. They're not actually trying to match it up with their energy use.

My colleagues in Northern States Power years ago they had the Republican National Convention at the Minneapolis Convention Center and Xcel Energy announced that the convention center was a hundred percent powered by renewable energy and I winced. I was in private practice by then, had been for a number of years. I had to call them up. I said I'm watching the convention tonight and it's dark outside and the wind isn't blowing, but the lights are clearly on in the convention center. Where is that energy coming from? And the answer was well, it's coming from our other coal and nuclear plants. I said so how can you say that it's a hundred percent powered by renewable energy and they said well, we allocated enough energy of our renewable energy to that activity. Besides customers don't understand the difference.

Customers don't understand the difference. They're going to about to have to need to understand the difference, because renewable energy is not -- is not dispatchable and it's intermittent. So matching -- actually doing a hundred percent clean energy renewable is going to be hour-by-hour something totally different than just announcing that you've bought enough RECs to serve your needs. And most of the folks who are doing these, God bless them, okay, they're either unaware of this difference or they're ignoring this tiny challenge or they're assuming that someone else is going to handle it. And those other folks are going to be the utilities -- are going to have to be the utilities that you regulate in large form.

There are some utilities that have taken on a hundred percent goals. Here's a listing of them. These are just some examples. There are others. The utilities certainly understand what a hundred percent clean energy would really require.

In California, they had a 50 percent RPS from Senate Bill 350 -- this is back in 2015 -- which required the IRP process by the municipal utilities. More recently, in the middle of our preparation of the IRP they raised the bar. They went to a 60 percent RPS by 2031 and a hundred percent zero carbon electricity by 2045.

The City of Los Angeles is now studying going a hundred percent clean energy in total and hired NREL, retired NREL, super choice, to do what's called the LA100 study to help them get there. I've got some charts of theirs. They're kind of illustrative.

And based on their experience a colleague and I wrote an article for the Electricity Journal this year called "100 Percent Clean Energy; The California Conundrum," because they're about to be a wash in the wealth of renewable energy that they're planning to build and they do not currently have plans of where to go with it. Bless them.

Los Angeles has hit the pause on a $2.2 billion gas plant reinvestment to rebuild their three big ocean-side natural gas plants with interest of going renewables instead.

Another California muni after some really bombastic city council meetings shelves their plan to do a new natural gas plant in the city. This is the City of Glendale, right next to my client, Burbank. So they're now in the process of striving how to nix their natural gas habit without letting the lights go out. And the thought of going -- as a planner and as a proponent for high levels of renewables and replacing the coal plants as they are retired as they age out, the thought of going a hundred percent renewables and tossing out the natural gas plants today terrifies me. We're still going to need some natural gas, at least for a while, at least for reliability sake.

Meanwhile the solar oversupply is growing in California. And again, the point where in subsidized solar where it's negatively priced and you have to pay people to take it during certain hours of certain low load days.

So why does California need something different and why is there -- are they a learning lab, again, for what we should be looking for in the future and not wanting to do in the future? Let's do the math. Okay. I'm a planner. Love the math. California electric utilities annual load factor, that's their average -- average load is about 50 to 55 percent. I would imagine North Carolina is probably similar. The annual capacity factor of California solar and wind is about 20 to 25 percent. A 60 percent RPS based on energy means California needs installed renewable capacity that exceeds their annual peak demand to get to 60 percent RPS. Okay. So they will have enough installed renewables and if they're all running, they'll be able to meet their peak demand -- singular peak demand of the year with renewables. All other days of the year when the sun is shining they will be over generating big time.

And because they're a north to south oriented state and I mention the term "time diversity," there is no time -- there will be no time diversity between their over generation. They're all going to be in the same boat at the same time. Here's what it looks like. At 60 percent RPS for a Southern California utility. Okay. It's a complicated chart, but what this is, this is the hourly load and generation output in a week in April in 2030 for well, this is Burbank. This is from our modeling. And to simplify the complication here is the black line that's running through the middle of the chart is the load they have to serve. Okay. And the yellow bars are the projected output of their solar installation that they're going to have in their IRP. And the green bars is the output of their wind machines they're projected to have. They're out because they have the -- they have the option of having wind, a 70 to 30 percent wind and solar mix is probably best for them. Okay.

Now, in the right-hand circle I will highlight just as an example above the black line, the green bars -- the yellow bars and green bars are adding up to more than what their peak demand is in a lot of hours. That is they're over generating. The renewable energy is coming at them and it's more than they can swallow.

But no problem. Okay. No problem whatsoever. And this is a fallacy of utilities doing their own IRP separately without talking to one another. The model just assumes as models usually do in the IRPs when you're over generating you have a surplus you sell it to somebody else. Okay. You just sell it off. Okay. Not the problem. That's how you balance your too much renewables with not enough load.

So I had a little theory and I showed this chart to my colleagues at a Southern California Public Power Authority meeting. They were talking about IRPs and I said and look how we anticipate Burbank is going to be over generating at certain hours, but that's not a problem, because we are going to sell our over generation to you. That's what our model assumes. And the room shuddered just as I was anticipating. Their models are showing them the same thing and their models are selling off their surplus to others -- us -- and we're all in the same boat at the same time. This is an issue that California hasn't dealt with yet as we're going for high levels of renewables.

Let's make it even more fun. All right. That wasn't enough. What happens at a hundred percent RPS. Okay. That's what the goal is, right; a hundred percent RPS. This is a chart during that same week in 2030 for the City of Burbank under the hypothetical that they do a hundred percent RPS and they do it all with solar. And the orange lines is the output of the solar facilities that they need to get enough energy to be at a hundred percent. A lot of the time -- and this is in April now, it isn't as bad in the summer, so I'm showing you more of a worst case situation during the spring part of the year when the loads are lower, but there are a lot of hours when they're producing way more solar than they really need. And then conversely at night there's no solar to serve the load, and so you have capacity deficits. And we produce this as an extreme, right? We're taking the 100 percent clean energy and you can't have fossil to its extreme.

So this is extreme and the scale is appropriate. If I did this and scaled it up and down for Los Angeles, for Redding, for San Francisco, this chart would be the same. And again, there's no place for this over production to go. In fact, we've done the math. There isn't enough load in the western United States to handle the over generation that's coming out of California. Okay. How to deal with that?

Here's a chart from the Los Angeles LA100 study from NREL. And what this is is the economics of the marginal cost of adding additional photovoltaics, that's on the vertical scale, with a horizonal scale as they go toward 100 percent renewable energy. And there's a certain saturation point as shown in this graph, starts around 60 percent, okay, incrementally, and then gets really pronounced when you get to 80 percent where the marginal cost of adding more photovoltaics goes asymptotic. That is it goes to infinity. And why? Every incremental amount of solar you added after a certain level gets wasted because it doesn't apply to the customer demand. The pattern of solar does not fit the pattern of customer needs. Okay. So how to reconcile? How to reconcile those? And their studies show four-hour batteries won't solve this picture very much. They need something of longer duration. So the conclusion is if we cannot sell over generation to surrounding utilities, and their charts look the same, find better ways of using renewable energy or build more storage, this is a rough estimate of what LADP would have to pay for PV.

I visited with my colleagues in Minneapolis at Xcel Energy who are wind based, very good wind resource. Okay. And I said okay, this is the picture for Los Angeles and solar. You've got a hundred percent renewable energy goal. What about this? And they said we have the same graph. It's a little different shaped, but we're north to south in MISO. The wind passes through our region from west to east and unless we find a different time diversified renewable energy source, we're not going to get to a hundred percent renewable energy. Stayed tuned on how California will end up. That's what -- net energy exchanges with somebody else somewhere else that has time diversified renewables. It is one of the initial conclusions of the LA study. They're still at work.

So what does that mean? I'll just take a few minutes to introduce a not so off-the-wall concept of virtual storage -- virtual storage. And it goes like this. Again, it's a complicated chart. I'll simplify it for you. This is from my friends at MISO. Okay.

If you look at the regions of the United

States northeast, southeast, so on, Southern California, there's very significant time diversity in when they peak load. The load peaks here in Raleigh at a lot different time than in Los Angeles. A lot different time in Minneapolis than in Los Angeles for example. Okay.

So the story goes if -- and everyone has their own generation reserves to serve their own peak load. Now, only if we could find a way to share our generation reserves over longer distances than we did before, then each of us can carry lower generation reserves and I can depend on your reserves at certain times when I'm peaking and you can depend on my reserves when you're peaking at a different time. Okay. This is a long-observed observation. This is transmission 101 actually. What's transmission for? It's to share generation reserves across regions. Now, the thought is starting to go what if you go inter-regionally with that idea.

NREL last summer completed a $1.5 million study called The Seam Study looking at this concept and it involves using high-voltage direct current transmission lines to connect the various regions and the "seam" concept comes from the fact that the eastern and western interconnections don't operate together. They are asynchronous. Their 60 Hz don't match up with each other. Okay. So in order to cross the seam, if you want to get load generation diversity from say Minneapolis to Los Angeles, you got to change it to DC somewhere along the way.

There are seven -- in the number 2 chart here there are seven little red bow ties today where they have substation size installations where the world goes from AC to DC for like from here to you and then goes AC again. Okay. And those seven installations are only about 200 MW each and most of them are more than 20 years old.

So The Seam Study was looking at what do we do to be able to jump over that seam with DC transmission with various options. And so they created a grid, an optimized grid situation with the help of Iowa State University. And what would it mean to build an overlay of HVDC transmission to move generation reserves inter-regionally?

Two hundred charts later the conclusions say, okay, a large scale national high-voltage direct current transmission overlay with renewables would be cost effective and by the end of the planning period thousands of megawatts of additional renewables will have installed. Most of the remaining Legacy coal power plants will have been retired during that timeframe. And we believe The Seam Study represents the coming transition to clean energy enabled by HVDC. This is something relatively new. Okay.

A week after The Seam Study was released, I was there in Ames, Iowa when they did it. Our team was on immediately after with the proposal for the project that would be the first instantiation of The Seam Study. DOE embargoed the entire Seam Study. You can't find it anywhere. It doesn't exist. We've got it in our files, but it doesn't exist. Crushed the NREL team. Okay. And the reason why was that last conclusion, most of the remaining Legacy coal power plants will have been retired, gone away.

But the coal plants are aging out anyway, right? I'm not a proponent of retiring coal plants, but if I look say at the upper Midwest where I'm from and look at their ages, they're all 35 to 50 years old. Okay. That's going to happen. How are we going to replace them is the topic.

And so we have developed a project -- and I'm just using this as an example, because we believe it has future application for North Carolina too if you extend toward higher-level renewables, this again, this was in Power Engineering magazine written by -- article by a colleague and myself.

And the short version of this is it starts with that Wyoming to Utah to California process of retiring a coal plant. It recognizes that there's a similar HVDC project from wind fields, again wind fields, to load from Iowa to Chicago. It's called the SOO Green Project. And we are sponsoring proposing a study on an interconnection called Power from the Prairie where it would connect those together, the DC, and potentially with grid-level storage in the middle. And what this does in simple form is it enables renewable energy swaps from one part of the country to the other.

Let California go wild building their solar. Okay. They're going to want to build it all in state. Okay. We understand that. Where they want the labor -- they want the work in California. Bless them. Do it. Okay. But when they create their own wonderful problem having too much solar, it has a place to go. They ship it up the DC line and it can't just go to Wyoming, because they'll have to spill the electrons out on the ground. There's no load in Wyoming. But continue on to places like Chicago and that's only where the size of the load is big enough to deal with the over generation they have in California.

So we are now in discussions with various utilities of doing this type of concept, but this is what we call virtual storage. That is, when you do storage, you take your energy and you send it off to a black box and it's gone away from you and later when it's right, the energy comes back to you. Now, did storage actually happen in the black box? Or did whoever was in the black box used your renewable energy and then they produced surplus renewable energy of their own and they sent it back to you? Okay. Minnesota Power is doing this now with Manitoba Hydro. They send their wind energy to Manitoba Hydro. Does Manitoba Hydro store it? No. But they over produce in their hydro later and they send it back to Manitoba virtual. Virtual storage. And we believe this has big potential for dealing with and addressing the hundred percent energy --

Oh, just as a little fun here. Here's part of what fascinates us about long east to west transmission lines. And where I'm going is yes, the high wind and renewable energy available in the upper Midwest can get to North Carolina, okay, via transmission. If you're people are in favor of high levels of renewables, got to be in favor of transmission.

But this is kind of fun. This is a -- let's see if I can zero in on it here. This is an hourly graph of video actually of hourly wind speeds during a couple of weeks in October across the United States. And I'll just stop it for a moment. The bright colors are high wind speed. The dark colors are low wind speed.

Okay. So let's let it run. And as we're familiar with weather systems cross the United States from west to east and thus the high winds cross the United States from west to east. The high wind that is in South Dakota where I grew up was in Wyoming yesterday. Okay. I haven't lived in South Dakota for 20 some years. I still hit the golf ball flat for good reason because it's windy there. It's windy there. Okay.

But the concept is if you can have a long transmission line, DC transmission line from say Wyoming to Iowa and you have connections of wind in --

to wind in Wyoming, in the Dakotas and Nebraska, in Minnesota and Iowa, what happens to the people who are connected to that transmission line is they get three bites out of the same wind apple out of each wind system. Okay. The folks in Iowa don't just get the benefit of their own Iowa wind regime and the electric output of that. They see the Wyoming wind coming at them electrically a couple of days before and in South Dakota and what this does is it makes the renewable energy much more reliable over more hours than just an isolated wind regime -- wind resources. So again, time diversity is important. And you can do that with a long transmission line. Okay. Enough about virtual storage.

So we believe that something like we're proposing as part of a national HVDC grid overlay and make it bidirectional both ways. Everyone is working on DC lines going from wind to load, from Midwest to the west or from the Midwest to the east. And we believe over the long term doing it making it bidirectional is the way to go. Okay.

Time for the lightning round. Let's have a little fun on some frequently asked questions on storage.

In the regulatory matters should storage be classified as generation, transmission, distribution, or load? And this question drives me crazy because people try to beat it into one -- into one hole or the other and you get zany results when that happens. For example, in Texas years ago the distribution cooperatives in Texas were prohibited from having storage, because they called it generation. They wanted to use it as a distribution asset, but they couldn't, because it was deemed as generation. So the answer is in any of these you should look at -- it could be any of these depending on the application and you need to avoid forcing storage into any one box.

And just for a little bit of levity here, I'm going to Saturday Night Live as an example of what I mean by storage can be multiple products. See if we can get this to work. Your IT folks have been great, so let's see if their efforts can be rewarded. And you can tell by the age of the actors here how long ago this comes from.

(PLAYING VIDEO.)

Okay. You got the idea. Storage can serve multiple functions. It's literally a floor wax and a dessert topping. And keep that in mind when you look at the application before you establish okay, how am I going to treat this, because it can be many different things.

Does storage reduce greenhouse gas emissions? Not really. Not necessarily. It typically tends to increase greenhouse gas emissions unless it enables more clean energy than would otherwise occur without the storage. So a storage unit often by itself doesn't reduce greenhouse gas. It depends on what it's storing and what it's offsetting.

How can we know if the storage is storing renewable energy or fossil energy? Well, the answer is where is the storage located on the grid and read the meters. Okay. If the storage is buried in the middle of the grid with conventional facilities and renewable facilities around it and brown and green electrons are flying by, you're going to have a real hard time deciding determining if it's really storing renewable energy.

And the alternative if the storage is physically in a place where it controls where the renewables are going, you can read the meters. If 100 MW is coming out of the solar and 100 MW is going out of the storage facility and 0 MW are going beyond it, chances are it's storing renewable energy. So you can document, you can prove depending on the configuration that it's actually storing renewable energy, but it's not necessarily storing it.

Should storage be eligible for investment tax credit treatment like renewables? And in my opinion, yes, it can be. If the -- it can be demonstrated the storage enables more renewables than would otherwise happen without the storage. Otherwise what's the point? If you want to associate investment tax credit with the storage with related to renewables, then it needs to be enabled renewables. Now, you might have other reasons for encouraging storage that you might want to assign tax credit, but if you want to make it like renewables, it needs to be enabling renewables.

Should renewable energy storage sent to storage qualify renewables or energy credits? I believe so, yes. That portion of the output that comes from renewables should be eligible for RECs if the energy input to the storage is not already eligible for REC treatment, so there's no double accounting.

This is debate in California. Okay. The definition of getting a REC is it has to be delivered within a certain very short time period in order to qualify the REC, so if I put it into the storage and this is the conversation, this needs to be worked out and I think they will work it out, that in the storage and it comes back out again to load, then that time delay does not keep it from being eligible for -- eligible for getting those RECs.

You can argue whether the storage losses are eligible for RECs or not, depending on how favorable you are you want to encourage the storage or not, but certainly the energy that goes in should.

Which is better for utility customers, distribute storage or grid-level storage? And they're not mutually exclusive options. Both will be needed. Okay. Which are they delivering lowest customer cost? Are they protecting the nonparticipating ratepayer from incurring costs. They shouldn't be doing this, but both, both should be --

What are the most likely applications for grid storage today? I think we covered it earlier in the grid discussion. What we found is as most valuable as a transmission asset and combined with renewables as an IRP alternative to other traditional fossil energy sources.

I haven't seen much -- it's really hard to pay for storage based on price arbitrage done all by itself. Okay. It's just really -- it's really difficult to do. It needs to have other benefits like displacing some other project that you would have done otherwise. You've got an avoided cost to compare it to, but as a merchant and you just using price arbitrage that's just -- as a side comment it's difficult to do.

What are the most likely applications for grid-level storage? Today it's on the distribution system to displace distribution substation or feeder equipment. Or where customers have particular high reliability requirements.

Here's a favorite of mine. Are four-hour batteries a one-for-one replacement for natural gas-fired peakers to ensure system reliability? No. Four-hour batteries can contribute to reliability. They have a role of reliability. But they're not as reliable as traditional peaking units. So you should not confuse the usefulness for daily duck curve operations as a substitute for installed capacity resource adequacy.

And we saw these effects in the Burbank IRP. In those scenarios that used rotating machinery like CAES or internal combustion units those scenarios were more reliable than the scenarios that used four-hour batteries, and we had to add more four-hour batteries to get the same reliability level. So we went all the way back to loss of load probability. I used to be the Mid Catenary Power Pool committee chair for doing their reserve requirement studies, loss of load probability. If you have a system that is -- has a lot of four-hour batteries in it in which you're relying for reliability, you need a higher reserve margin mega -- in percent than conventional generation.

In fact, we found that CAES plus storage -- CAES storage and renewables is usually an eight to 11 percent capacity reserve margin. Internal combustion engines were relative similar. But the four-hour battery scenarios needed a 22 to 27 percent reserve margin, so in effect we needed eight-hour batteries, not four-hour batteries, so we're just stacking four-hour batteries on top of each other to get to the same reliability. So read the small print.

I saw and what ticked -- put me off was a recent story where someone did a big article about oh, look, we did an analysis and we found four-hour batteries can replace peakers in New York. Well, they must have found some peakers that were only running two hours and no more. Very selective, so --

How do four-hour batteries compare to reciprocating internal combustion engines for reliability service? You need about twice as many megawatts of the batteries than you do as the internal combustion engines. But the overall costs were about the same. Again, that's in the Burbank IRP.

Is value stacking to monetize storage benefits real? Well, it is real in non-RTO markets. And the utilities like Duke are implicitly doing that internally. Okay. They're -- they can internalize the value of storage to themselves, okay, which is a beautiful thing. Okay. They can internalize it for the value. They can focus the value of the storage and their operations on maximizing the benefits of their own renewables. They can -- it can internalize the value of storage for contributing to their ancillary services requirements. They can internalize the value of using storage for spinning reserve and black start or whatever is the case. Okay. So that happens and it happens in the normal course of business.

It's really the RTO markets, but it's -- but boy, is it hard to get there. Okay. Comprehensive tariffs are not yet available to reward all the value attributes of storage in the RTO market, so a lot is made of storage in the RTO markets and bless them and they had a lot of complicated tariffs to do it, but they're going to need a lot more complicated tariffs to do that.

Here let me give you an example. If she runs her storage and her wind machines benefit from it and his coal plants benefit from it because they don't cycle as much, so they have less on them, they get the benefit. She's paying for the storage. Okay. So you've got a free-riders issue going on in the RTOs. While that storage goes out there that is the benefits of the storage appear not all at the storage site. They appear elsewhere.

And how does the market compensate for that? What is the value -- what is the tariff for reduced renewables curtailment? Ever heard of that tariff? No. Okay. So a lot of work to be done in the RTO market. Bless us that you're in North Carolina. We're not faced with having to do a lot of that.

Is it easier for a storage owner to monetize their storage investment in an RTO ISO market or in a vertically integrated market? If the storage owner is a utility, it's easier in a vertically integrated market as I just indicated. Okay. A vertically integrated utility an internalize all the benefits of the storage. If they own the storage, they can operate it to benefit their own renewables. Okay. So they got their arms around all those value streams. Okay. That's a good thing. But the storage owner is a merchant, it's easier in the RTO ISO market only because there are some tariffs available for them to get at it. Otherwise they got to go negotiate every one of those pieces with the local incumbent utility, okay, which can be done with encouragement of the Commission perhaps. It's just not easy.

And, of course, you're going to read all about it. I've written a paper about this with a legal colleague in the RTO ISO markets.

The FERC has some dockets going on about storage right now. They're talking about mainly interconnection issues and storage, and storage being able to access the market. They're not dealing with these value monetization issues at all yet. And this is before distributed storage tries to get to the wholesale market. I don't want to make it sound complicated, but --

Finally a last word and my death by PowerPoint is concluded. Okay. A word about ancillary services, because again, much is being made about this and I'm speaking to the RTO ISO markets. Some new information suggests that ancillary services markets are finite in size. So while a lot is being done for storage to be able to access and monetize and value stack their ancillary services in the RTO markets, it might be a short visit -- let me give you an example.

PJM has about 178,000 MW of generation. 178,000. Their regulation market is about 800 MW. Today they have 3,000 MW of batteries either installed or in the queue. So as soon as the get that frequently -- that regulation tariff out there in operation and they put that out for bid, what do you think is going to happen to the price? 3,000 MW of batteries today in an 800 MW market and they're all looking to sell into the frequency market. So I look forward. They're doing good things. But watch out for when we create a market so someone can value stack and is the trip worth it once you get there and is the market big enough.

I've been all over the place on storage here today on these various topics. Grid-level storage. We talked about batteries and long-duration storage. We talked about the drive for clean energy. Bless my heart, our City of Burbank listened to our story of 68 percent renewables and 87 percent greenhouse gas emissions, and then they told us they wanted to go for a hundred percent clean energy by 2040, which is five years earlier than the state required. Okay. Okay. So that's the assignment of the Burbank Water and Power to proceed.

And I'm happy to answer any questions you've got about storage. So I covered a lot of ground here. Thank you for your patience and your questions and your interest.

CHAIR MITCHELL: Questions from Commissioners? Commissioner Clodfelter?

COMMISSIONER CLODFELTER: Your slide 95, can you scroll back to that?

MR. SCHULTE: Which one?

COMMISSIONER CLODFELTER: Ninety-five. So let's see if I can frame the question correctly. So what we are experiencing here is storage owners who are effectively merchants, that is they're not the utility, they're third parties --

MR. SCHULTE: Uh-huh (yes).

COMMISSIONER CLODFELTER: -- but they're wanting to sell and sell and provide ancillary services so they say --

MR. SCHULTE: Yes.

COMMISSIONER CLODFELTER: -- to the regulated utility. We've got to figure out how to value and design tariffs for that. Has anybody succeeded in that challenge?

MR. SCHULTE: I dare say we might have hit on it in Burbank. And thank you for your question. Okay.

You can with an IRP model quantify how many batteries -- one-hour batteries in megawatts that a utility needs for frequency regulation. That's a number. And should you decide to open that up where the incumbent utility, the regulated utility doesn't just do it and rate base it, but you want to have others participate like that, it seems to me put it out for bid. That way you find what the lowest cost is for it, you know, and -- you know, and you may reserve a portion of that, those batteries, for the incumbent utility like you do for your renewable energy as I understand it, a portion of those procurements, you might allow them to set aside a portion for themselves and that they can rate base, but put it out for bid, and then that way it seems to me you have created a competitive value in price and opportunity to have third-parties participate in that market.

So you're unbundling, right, that portion, your parsing that piece of the activity surgically out, but it seems to be based on what we learned in Burbank, and this is pretty new, you can -- that number is achievable. You can -- there's ability to do it and I'm happy to provide, you know, staff, the folks who are -- who do those types of -- they're out there doing webinars now about how you do a modern IRP using batteries for ancillary services. I don't have a financial relationship with them. There's no quid pro quo between me and them. Okay.

But you can do the same thing for ramping. Okay. Within modern IRP software, you can look at the ramp that's required, the maximum ramp that's required in a maximum day. It doesn't have to be the duck curve of California. It can be local. It could be -- could be you're ramping down at the end of the day. You can tell you're getting enough solar. We actually have duck curve if you ever have that. And you can quantify how much ramping, the utility can do that, they can quantify how much ramping they need.

Now, they have existing resources that have ramping capabilities, okay, which can contribute. So Burbank has combined-cycle and simple-cycle units which were included in the analysis and they will contribute to that ramp. But there was more ramp than their existing facilities could do. And four-hour batteries and batteries can do it faster and perhaps better. And there is the modern IRP software, it will tell you how much ramping you need. So that's a number. Okay.

And then you can do a similar thing where you go okay, say the utility has so many megawatts of ramping they need by 2030, put that out for bid and you let the incumbent utility keep a portion of that for themselves and rate base and you competitively bid the rest and let people bid for it and you see -- and maybe you bid it all out because the prices are good, maybe you're not. Okay. But you know -- you then know with data what the right price is for the ratepayers, because it was competitively done. And I believe that can be done.

COMMISSIONER CLODFELTER: The IRP modeling would show you what your need is on the assumption that it's utility controlled. So when I go out to bid to the market, I've got to have certain protocols about operation that I stipulate in the bid specs, right?

MR. SCHULTE: I'm sorry. What --

COMMISSIONER CLODFELTER: I want to be sure I get --

MR. SCHULTE: Absolutely.

COMMISSIONER CLODFELTER: Absolutely.

MR. SCHULTE: If I, the utility ratepayer --

COMMISSIONER CLODFELTER: Right.

MR. SCHULTE: -- if I the utility ratepayer is paying for that ramp, I want to control it. So I cannot let the local requirements of the storage, whatever that is, drive -- distract -- distract when that moment when I the ratepayer need ramping that I paid for. No, it has to be under control.

COMMISSIONER CLODFELTER: Nonperformance of the bidder under the contract --

MR. SCHULTE: The LDCs --

COMMISSIONER CLODFELTER: -- is not -- is not allowed.

MR. SCHULTE: No, the LDCs are heavy, yeah --

COMMISSIONER CLODFELTER: It's not allowed. Right.

MR. SCHULTE: -- like don't not perform.

COMMISSIONER CLODFELTER: Right.

MR. SCHULTE: Yeah.

COMMISSIONER CLODFELTER: Thank you.

MR. SCHULTE: Yeah.

CHAIR MITCHELL: Additional questions? Questions from staff?

MS. JONES: Bob, could you talk a little bit about using storage to replace transmission? And to start with typically a transmission project from what I can tell the utilities put load growth into their models and it shows that a certain transmission segment five or 10 years in the future is going to be overloaded under a contingency and so they need to add some transmission capacity. What I don't understand is typically that contingency that triggered the overload, it's not going to have a four-hour or even an eight-hour life. It could have an eight-week life. Help me understand how storage can help.

MR. SCHULTE: If the contingency is more than say what a battery can do, I'd really question whether storage can be -- could be that offset. You know, because the contingency might be the overload of some other system element. For example, it might be loss of a transformer or something somewhere else, which causes loading on that particular transmission element.

So yeah, if you're talking about contingencies that are longer than say the storage can handle, probably not. Probably not. And even if you stacked -- you stacked a bunch of six-hour storages to make 12-hour storages, the costs gets -- the costs get out of hand. When we looked at the cost, for example, under a hundred percent renewable scenario of Burbank surviving a two-day cloudy period or non-windy period using batteries, I mean, reliability issue is not a few hours anymore. It's having enough energy in storage for several days. It would've tripled their electric rates to do it. So -- so yeah, I would doubt that that would be offhand. I'd need to see the details, but if the contingency is -- the driving contingency is longer than the storage lasts, then I don't think so.

CHAIR MITCHELL: Commissioner Hughes?

COMMISSIONER HUGHES: For your forward-facing modeling when you're looking at battery storage, what are you modeling as costs for like you just quoted a number of a future cost for using batteries for a certain objective? How are you projecting, particularly with batteries, cost in the future?

MR. SCHULTE: What types of costs are we using?

COMMISSIONER HUGHES: I mean, going up, going down, you know --

MR. SCHULTE: Oh --

COMMISSIONER HUGHES: How is your --

MR. SCHULTE: Oh, you mean in terms of trending?

COMMISSIONER HUGHES: Yeah.

MR. SCHULTE: Yeah. They're a very sharp trend downward. And so we were using -- because our initial installations was in 2025, we were using the projected cost in 2025. And those are the numbers that are on my earlier chart, the dollar-per-kilowatt number for four-hour, one-hour, and a half-hour batteries and our modeling contractor was a battery enthusiast, so they were -- they were -- we believe they were fairly aggressive. During the period of the 20-year planning session we continued that trend. If we had to replace cells or we added batteries, then we continued to add them lower as the trend rose.

So you got to -- you got to recognize the trend that's happening and then respect it, because it is happening. It's flattening out a little bit, but, yeah, it's really real, so yeah. Great question. That's what we were using in Burbank. We thought it was reasonable.

CHAIR MITCHELL: And how does that trend compare to the solar PV cost trend looking forward?

MR. SCHULTE: If I drew them both out with an interpretive dance here, they'd both look like -- they'd both look like that at the same time.

CHAIR MITCHELL: So they're trending at the same rate. You don't see battery cost declining more rapidly than solar?

MR. SCHULTE: I don't have the charts in

front of me. I'd be happy to provide those examples that are there. I think both have the uncertainty of technology -- a technology jump that could be disruptive discontinuity again downward and start another downward trend. That's happening, so I -- both of them are on a downward trend and those are going to continue.

CHAIR MITCHELL: Commissioner Clodfelter?

COMMISSIONER CLODFELTER: You had a series of slides on your FAQ section that talked about four-hour batteries as substitutes for a peaking fast-start turbine unit and so forth and comparing with other things. The combination I'm interested in hearing you comment on is was not one of that series of slides, but it would be I'm interested in bridge technologies. Rather than investing in 15 to 20-year assets, maybe investing in 10-year assets to see how the technology and the costs evolve over a somewhat shorter period of time before making the long-term investment. So comment about the combination of -- which you said a little bit about, but comment about the combination of RICE units and renewables or RICE units and four-hour batteries as a substitute for a fast-start combustion turbine.

MR. SCHULTE: Well, in our analysis the combination was one of the leading lowest cost options there among the three options that beat a conventional combined-cycle gas turbine unit with renewables by quite a ways. That they were -- they're modular relatively so run them at 10 - 15 MW, you know, increments or 8 MW increments. If you can build them in building blocks as load happens, you don't commit to a big megawatt number. You put them in a row.

There's a nice installation near my former hometown near Shakopee, Minnesota. They've got them, integrating renewables. So I think that's a really good option. They have some -- they have some greenhouse gas emission profile, but other than that, they were -- they're one of the leading candidates for the Burbank IRP.

CHAIR MITCHELL: Any additional questions? Okay. Mr. Schulte, thank you very much for being here today. We very much appreciate your remarks. Commissioner Clodfelter?

COMMISSIONER CLODFELTER: Did I understand you're open to subsequent dialogue with staff about the IRP modeling?

MR. SCHULTE: Sure. We're continuing on

afterward here, so bring it. I look forward to it.

MS. JONES: I do have a real quick one. Bob, do I take it from your discussion about California that the energy imbalance market in the west is not going to solve the problem of too much solar? That even with that big market they're not able to absorb it all?

MR. SCHULTE: The energy imbalance market would be a good way for a lot of the utilities to save money in their dispatch of their other renewables, but no, the quantity of renewables that are going to be there is going transcend the benefits of the energy imbalance market. Yeah.

CHAIR MITCHELL: Okay. Thank you very much.

MR. SCHULTE: Thank you. It was an honor to be here.

CHAIR MITCHELL: Thank you.

(The proceedings were adjourned.)

C E R T I F I C A T E

I, KIM T. MITCHELL, DO HEREBY CERTIFY that the Proceedings in the above-captioned matter were taken before me, that I did report in stenographic shorthand the Proceedings set forth herein, and the foregoing pages are a true and correct transcription to the best of my ability.

Kim T. Mitchell
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Kim T. Mitchell
Court Reporter