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TIME IN SESSION: 1:03 p.m. to 3:12 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

Commissioner Floyd B. McKissick, Jr.

IN THE MATTER OF:

Investigation of Energy Storage in North Carolina

Presentation by:

Dr. Imre Gyuk, Director of Energy Storage Research,

Office of Electricity, U.S. Department of Energy

and

Patrick Balducci, Chief Economist,

Pacific Northwest National Laboratory

Volume 3

P R O C E E D I N G S

CHAIR MITCHELL: All right. Let's go ahead and get started, please. Good afternoon and welcome. I'm Charlotte Mitchell, the Chair of the North Carolina Utilities Commission, and with me this afternoon are my colleagues Commissioners ToNola D. Brown-Bland, Lyons Gray, Daniel G. Clodfelter, Kimberly Duffley, Jeffrey Hughes, and Floyd McKissick.

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

We're happy to have with us today Dr. Imre Gyuk and Patrick Balducci. Dr. Gyuk is the Director of Energy Storage Research, Office of Electricity, with the Department of Energy, the United States Department of Energy. Mr. Balducci is a Chief Economist for PNNL.

Our speakers will be working from slide decks that will be displayed on the monitors here in our hearing room, and the slides have also been posted on the Commission's website in Docket Number E-100, Sub 164.

Our court reporter, as she has done in the past, is creating a transcript that will be filed in the docket and available on the Commission's website. These sessions are structured for the benefit of the Commission's learning and understanding, and the speakers will be asked to share their expertise and answer the Commissioner's questions as they arise. People in the audience won't have the opportunity to ask questions; however, if you want to file information in this docket in response to what you hear today or if you would like to suggest additional speakers who could appear before the Commission, please do so.

Okay. If it's okay with our presenters, we'd like to ask questions as we proceed, and I will ask Dr. Gyuk to proceed to the chair. I will turn it over to you. Thank you for being here today.

DR. GYUK: Distinguished Commissioners, it's a pleasure to be here in North Carolina, a state that frequently I only come to in the summer in the Outer Banks, but I am well aware that there are many other things North Carolina has to offer, and some of them right here. The Research Triangle, distinguished science going on. I used to work with NIH at one time and have pleasant memories of being here in Raleigh.

So today I'm going to talk about grid scale energy storage, particularly for resilience, stability, and, well, a greener grid.

I direct the Energy Storage Research Program at the Department of Energy, the Office of Electricity, and I've done so, well, for the last 20 years. In fact, we started this energy storage thing when basically nobody else was thinking about it. You'd mention it to utilities and their eyes would glaze over and say, well, storage, why would we want to do that, except, of course, for utilities that pumped hydro because those know the importance of storing energy. So energy storage -- the Energy Storage Program, and I'm going to talk from the program, although I'm going to look nationwide as well.

In our office we do a broad range of research and development, deployment, and analysis. And the reason for that is because, well, when we started, there was nothing else there, so we had to do the entire spectrum and it's all integrated together.

We start with materials, we go to devices, on to systems, analysis, standards, policy, finance, safety, and various other things. We team with Sandia, Pacific Northwest Laboratory, Oakridge, and also with Argon and Los Alamos National Laboratory, and we work with industry, states, and utilities.

We're pretty good at what we are doing. Among other things, we have 10 R&D 100 Awards, which are sort of the Oscars of the technology world, and recently we have gotten two EPA Green Chemistry Awards.

Next one, please. The way the program and, if you wish, the entire field of storage is organized, it starts with materials, and we specifically are interested in sodium-based materials, aqueous soluble organics, and zinc technologies. Now, you don't see lithium there because lithium is pretty much an established sort of technology, so there's not much point in doing research except when it comes to recycling and various -- and safety. Okay. Then we also do power electronics, safety. Reliability is very important because not all devices are as reliable as you might wish them to be. And then we are very much interested in providing state regulatory support, dealing both with state regulatory agencies and public utility commissions. Use case evaluation, this is the thing -- this is a new technology, a new science, if you wish, and we really have to still find out what it's good for. Okay. And increasingly we know what it's good for, but it started simply with a conviction that something like this ought to be done and ought to work. And so we're developing more and more use cases, and we're evaluating them and making sure that they really provide value. Performance protocol, and then above all, safety.

So when you design a business case, there are two things you have to keep in mind, the cost and the value. And it's very important to realize that these are not the same thing. Okay. Cost and value, eventually, hopefully they will meet in the middle so that, you know, you have value for cost. But at the beginning there is a lot of incentives, you know, money put into the thing simply to find out what -- whether we can make it work. But I, in my program, am always looking for getting a business case that pays out, monetary -- it's got to balance monetarily.

So the cost. The cost has three main components. The first one, of course, is the energy storage device itself, the battery, if you wish, but there are other devices as well that could do it. But interestingly enough, that's only about 40, 50 percent, sometimes as little as 25 percent. Okay. So the battery is essential, but it's not the be all and end all, because then you have to take -- think of the power electronics. The power electronics and the control system is what makes this thing perform properly.

And then there is the balance of plant, the facility, which is at least 20 to 25 percent. And you have to think of this, you've got your batteries. You have to put the batteries into a pack. Then you have to put the packs into a rack. Okay. The racks will go into a building. Now you have to have air conditioning, particularly with something like lithium which will warm up too much. You have to have fire suppression equipment. You then have to put your building on a pad, on a place for which you have to pay rent, essentially. And then come the building inspectors, the lawyers, the cost of money, the insurance, the reinsurance. So all of that together -- the commissioning -- all of that together is a lot of money, and the cost of that is not going down as fast as the cost of the batteries.

Okay. Let's look at the value. The value will generally depend on multiple benefits. Okay. You can't do storage on one benefit alone, in general. You've got to take a number of benefits into account. And some of those are monetized or easily monetized and some of them are unmonetized. Monetized ones, for example, are arbitrage, you know, buy low, sell high, essentially; frequency regulation, which is one that we worked -- that my group worked out in the very beginning; demand charges, which can come by the month or by the year. Now, in a vertically integrated utility you don’t have these market values, but you have the equivalent. I mean, the values are still there; you just don’t have them written down as a standard thing. And then come the unmonetized ones like resiliency. Very difficult to work with and -- but very important. So how do you build business cases on resiliency, sustainability, and grid stability? These are the main things that you’re looking for.

Values such as resiliency, military energy assurance, emergency preparedness, these are all very difficult to monetize, but often these are the primary reason why you want to put a project into place because you want to have reserves, okay, or because you want to be safe when the -- to make sure the lights don’t go out. It's very difficult to monetize.

We know that microgrids, together with renewables and storage, provide good solutions for resiliency and military energy assurance, et cetera, but they don’t provide the monetary justification. If we do a business case like this, it has to be -- has to rest on the monetizable part of the situation. There’s usually one part that you can monetize, and that’s the one that you have to rest on, and then the others are sort of side benefits.

One way, of course, to deal with unmonetized one is to monetize them by mandating them. Okay. If you say you shall do this, then that automatically provides a value.

So I'm going to give a few examples, all of them different, of how these values can be established; a very nice example, Sterling, Massachusetts. Now, that's within ISO New England, so nice market values, et cetera. What happened there is the Massachusetts Department of Energy Resources gave out grants to 11 cities of about a million, million and a half dollars for resilience. And then all of these cities said, well, yeah, what do we do now, okay, because the expertise to deal with this is simply not there in small towns in general.

So what we did at the Department of Energy, we sort of adopted one of these towns that seemed to be particularly promising, and we saw them through the whole process. Okay. And the first thing we did is we said, okay, you would like to put storage into your police department. That's very good. It's a dispatch police department. It can serve the community. You'll know what's what and, you know, they can -- they can do this.

But wouldn’t you like to make money on this? And, well, the answer, of course, is always yes.

And so what we did is we brought the situation to Sandia National Laboratory. We took all the data. We put it on the big computers and built a model, and we showed them that by utilizing the monthly and yearly demand charges, as well as arbitrage and optionally frequency regulation, they could make the system not only pay for itself, but do it in six and a half years which is pretty neat. So the thing goes from being a government sinecure to being something that actually pays for itself.

So I’m showing here what the prediction was, and it turns out that the yearly peaks are the biggest thing. The way it works is that during peaking situations, the storage kicks in and brings the peak down. In the first year the actual recorded savings were 11 million for arbitrage, 143 million for -- sorry -- $11,000 for arbitrage, $143,000 for monthly peaks, 240,000 for the annual peak, for a total of about $400,000, which is exactly what we had predicted.

And since then, if you look at the -- at the graph, this is ongoing. I mean, you profit every time. By April 2019, two and a half years into the project, we had produced $1 million in avoided cost. Since then the place has become rather famous, and delegations from Germany, Switzerland, Denmark, Sweden, England, Ireland, Australia, blah, blah, blah, blah, and Thailand have visited there to see how you can do storage and do it the right way and make it pay for itself. Next.

Another project that we did, completely different situation, is a small town, Cordova, in Alaska. This is isolated -- in order to do -- they are based on hydro, which is a good thing, because they have plenty of hydro. However, the hydro -- run of river hydro is very difficult to control and they have -- when they have too much hydro, they can just spill the water, that’s okay, but when they have too little, then they have to kick in diesel, and diesel is very expensive. So at the moment, the generating capacity is 6 MW plus 1.25 MW of hydro and twice a megawatt of diesel. And half a megawatt is always deflected as spinning reserve.

This is expensive because the hydro is very inexpensive at 6 cents a kW and the diesel is 60 cents a kW. So you want to change from diesel to hydro, and we did that by installing a megawatt of storage. It works well. It does exactly what it is supposed to do. And we are now exploring to see whether we can find other uses to make it even more so. We have the ribbon cutting here, the unit here, and the commissioning was just recently, June 7th, 2019.

One other nice thing is you can put up a megawatt of storage very quickly. If you know what you're doing, you can -- after the study has been done, you can put up a megawatt of storage in three months. That's what we did in Sterling, unlike a power plant which takes considerably more, if you take into account the siting and, well, the building as well and so on.

Then there's an example in Nantucket, and the situation they had there is they had two cables that serve Nantucket Island. Well, what with a lot of tourists, the two cables are beginning to be not enough for peak situations when the tourists are using up -- using up all the electricity. So it was contemplated to do a third underwater cable. Very expensive. Okay. Instead, a storage solution was proposed, and Pacific Northwest Laboratory, Patrick Balducci and his group, did the analysis, and it turned out that the storage is much more cost effective than putting in a cable. And that is just going with basic cost. Okay. I have the data there. Patrick may talk more about this.

But worked very well, and this is a big one, the deferral value amounts to about $110 million, plus $36 million in operational benefits, with 6 MW of eight-hour storage installed.

Again, the ribbon cutting, you may see me over there instructing them on how to cut the ribbon which turned out to be very difficult because it was a plastic ribbon, and using those big scissors was very difficult to cut, but we managed. Okay.

PNNL worked out the financial benefits, technical impact, and the control strategies. Now, they did not yet do a lot of other benefits which are hiding in there and which we will look to in the future. This was a system, by the way, with Tesla. And it has a very good return on investment of about 1.55 -- well, investment. Ribbon cutting in October.

Okay. We have a lot of other projects, and the point is to have a different business case for each of these projects. We work with the Albuquerque Public School System. If one of those works well -- it’s one of the biggest school systems in the country. If we manage to do well on one, we get all 140 campuses. And they are -- they are very interesting. They have a control room where they keep track of all of their water, gas, and electricity. And if they have a little bit more than customary water out of one of the schools, they call the school up and say, hey, one of your toilets is flushing too much. Anyway.

We have a project with Picuris Pueblo. This is interesting. We work with a number of Indian tribes, and the goal there is energy independence because they have realized that they have to rely on their own -- on their own framework if they want to be -- have a certain measure of independence, they have to be energy independent as well as independent otherwise.

By the way, I forgot to mention, obviously, the Nantucket example might have very nice applications in places like Ocracoke and the Outer Banks.

We have three projects involved in rural co-ops and military reservations, again, military assurance, very important. Another Alaska project. And we are taking on a really big one, three -- five towns in Puerto Rico that have formed the consortium for a Central Mountain microgrid powered by 250 MW of solar and hydro, with 75 MW of storage backup. If that works, then that entire mountain district is going to be electrically independent and, well, as you may know, we had not only the hurricanes, but recently there have been earthquakes and whatnot. And the electricity system is always one of the first ones to go. So if you want to be secure, you need to do something along that line.

But what I'm really after is not just little projects, but to do this nationwide, and what is emerging is a number of storage ecologies, states that are paying attention that are adopting storage, developing the art of applying storage further from where it is. And generally what you'll need to do this, you need some congressional and state support, you need a regulatory structure that is friendly to storage. It helps to have a national laboratory, universities, perhaps, that will champion this, utilities that are in the forefront of innovation, and real projects, as an example, in the state.

So among the areas that are developing as such storage ecologies, California, with its mandate, with California Energy Commission, and industry. I'm not personally necessarily in favor -- in favor of a mandate, but for California it worked because it really kickstarted this whole business. New York, who have BEST and NYSERDA, and places like City College New York to develop new technologies. The Northwest, Washington, Oregon, Alaska. They have Pacific Northwest Laboratory to help them with both technology and policy. Forward-looking organizations like the Washington Clean Energy Fund, the public utility commissions that have had -- where we have had input just like we have here now, and the members in the Senate who are looking at storage very seriously. New Mexico is coming up. New Mexico was thinking of establishing goals, but they decided that they didn’t have enough storage yet, and it would be silly to establish goals when you haven’t got any good examples yet, but we do have congressional support and we are beginning to have projects there. And you’ve just heard about Massachusetts, which works, too.

Now, some of the states have very big plans. California wants to do a hundred -- a million, three hundred MW by 2020 and another 800 MW on top. 2020 is already upon us. Okay.

Massachusetts, little bit disappointing because they are -- the study they did asked for 1,000 MW. Well, they finally voted for 200 MW by 2020, but maybe it’s better to be conservative. Who knows? But they have recently upped this to 1,000 Mwh which isn’t all that much because 200 MW for four hours would be about 800 MW, so it’s a relatively small increase.

New Jersey, a very big goal, 600 MW by 2021 and 2 GW by 2030, eventually. New York, 3 GW by 2030, also.

Arizona is an interesting case. They have suggested 3 GW by 2030 proposed. Arizona Public Service came up with plans for 850 MW and then they had a fire, and so everything is up in the air now. We have a group at Sandia National Laboratory that is helping them look into that. It’s very difficult because they are at least -- well, it’s full of lawyers nowadays, and it’s very difficult to get real information out of it because, you know, each party in the picture is trying to make sure that they didn’t do anything wrong, but, you know, lives have been lost there or at least jeopardized. It's a very bad situation. But I trust that eventually they will work it out and Arizona will have goals as well.

Little Maine has 300 MW planned by 2025. Nevada does not have any official plans, but they are setting up 380 MW of four-hour storage at a solar farm on federal land. Okay. Solar farm on federal land is sort of everybody wins a bit because, well --

So DOE is happy to provide technical assistance, and those states that are interested we have been visiting. We’ve held a Southeast Symposium with states from Alabama up into Virginia. We’ve done half-day workshop with New Mexico. That usually involves Sandia National Laboratory and PNNL. Michigan, we’ve done a one-day workshop. Arizona Public Service, we've worked with the IRP workgroup to establish best practices. CEC we work with regularly. We have worked with the Energy Storage Commission in Maine.

Next week we are at the Nevada PUC on a one-day workshop on policy and valuation, modeling, interconnection, commissioning, safety, et cetera. And we are planning a New England conference of PUCs for the New England states.

Overall, we can say that energy storage has become a resounding success, with big plans all over the place. I'm not going to quarrel about the exact figures. They change all the time, and they change depending on whom you ask, but -- well, everybody has this exponential sort of curve. Next.

But there are also issues. As you will know, the lithium ion is the incumbent technology. Most of the applications are lithium ion, and lithium ion has problems. There are ecological and sociological issues. The cobalt in most of your lithium storage is scraped by little boys in the Congo. Not a very desirable thing for a world technology. You know, that's got to stop. And, of course, if that stops, prices will go up, you know.

The other ecological problem is that it uses a huge amount of water and depletes the groundwater in areas where it's being used to the point where -- well, of course, mostly it's a desert, but it's water that local people rely on, and the groundwater is just going down now.

Serious issue, safety and reliability. The thing -- well, chemical storage is almost by definition unstable. Okay. It's just a matter of degrees. Some are more unstable. Some are less unstable. Lithium is quite unstable. Okay. You've got to be very careful that you don't have a thermal runaway and fires can be spectacular.

Serious problem is the lack of recycling. You really can't recycle lithium very well. Once you have used it, most of it goes on the trash heap.

So there are pros and cons for lithium ion. The pro is it's low cost and it's market ready, and it's the dominant technology and it's familiar. We know how to work with this. We know how much it should cost. There are companies that are well known that will be here five years from now and, if necessary, can pay -- can be responsible.

Contrary, the cons, cycle life is considerably less than 20 years; more like 10 years or even eight years in bad climates. It shows capacity fades. In other words, the capacity of the battery goes down, down, down before it abruptly fails.

Safety issues, well, I mentioned them. There have been 15 MW -- 15 MW scale fires in Korea during 2017 which is where a lot of the material is produced. Arizona had a big one in 2018. There have been 225 aviation incidents with lithium ion. So I don’t want to scare you, but it’s there and it’s to be considered, so in any mandates you consider or any goals you consider, you have to build in safety features as well.

And there is no real U.S. manufacturing. Yeah, Tesla has a plant, but it’s really a Panasonic plant. You know, it’s not really U.S. manufacturing.

And as I mentioned, no recycling. Recently, Argon has taken on a serious study of recycling and, you know, we have worked a little bit with reuse. Particularly, electric vehicle batteries, when they are down to about 80 percent and have to be retired from automobiles, they could be used for, for example, low income housing, for supporting solar, but there -- there are a lot of issues in there. You can take them apart. Finally, you can melt them down. But when you do that, the only thing that you can really pull out of it cost effectively is the cobalt which we would like to get out of batteries in the first place. So hopefully five years from now we will have cobalt-free batteries that do not rely on this rare commodity which is being mined in sociologically unacceptable ways. So it’s being considered, but it’s far from resolved.

So we do a lot of materials research trying to develop new technologies and looking into safety, reliability, and recycling.

One thing that I want to call to your attention is flow batteries. Flow batteries are quite different from lithium-ion batteries. Basically, you’ve got two big tanks with the chemical and the chemical pumps, and when it meets in the electric chemical cell in the middle, it generates electricity. And you can run the whole thing backwards and put electricity into it and charge up the tanks. And if you do this right, first of all, you can build it as -- you can build it much bigger and you don’t have the degeneration that you have with lithium. So it’s something that a lot of studies have going on. It’s really analogous to a car, where the power comes from the engine and the energy is in the gas tank. A number of them are commercially available, but not nearly in the scale that lithium ion is available.

And, of course, what we are looking at in flow batteries as well as in other technologies that are being concern -- concerned are earth-abundant materials, things like sodium, vanadium even, manganese, magnesium, carbon. These are the ones that we are looking towards that are literally dirt cheap and where it depends on our ingenuity to -- rather than the commodities market.

The cost goals for these technologies that DOE is working with are somewhat lower than lithium-ion batteries. Lithium-ion batteries, at least the cells, we're probably not going below $100 per kWh because they have been very well searched -- searched out, and when you -- considering the system, we may have to be -- we may have to be spending more for things like fire prevention equipment, larger boundaries to keep them safe, air conditioning that's more carefully worked out. These things -- higher insurance. These things may be driving lithium prices up. So -- but for the cells alone, let's say a hundred.

Vanadium flow batteries, we have driven them down to 300. Technologies which we are now working at, zinc manganese we might go down as low as $50 per kWh, low temperature sodium and sodium-ion based batteries $60 per kWh, and very tantalizing, aqueous soluble organics rather than metals use organic substances, maybe 125. But if we do this, we will be independent of any imports from elsewhere. In fact, all of these things are -- the resources are abundantly available in the U.S.

And we have to keep an eye out for advanced lead. There hasn't been much movement research wise in advanced lead batteries, but we believe there are considerable advances to be made as yet, and we may be able to make it lower than anything else, like $35 per kWh. And lead acid batteries are fully recyclable to 98 percent or so, which is outrageously good. And they have a complete industry that recycles these batteries, which is more than any of the other technologies can say.

On the horizon we have non-lithium technologies, better lithium like Innolith. We've got vanadium redox, zinc-bromine, zinc-manganese, iron-chlorine. DOE has worked with all of them. We have done research in all of them. All of them were promising ones. You know, they are promising, but that's all I can say about them. And some of them are commercially available.

Non-battery technologies are being considered. Pumped hydro, after all, is a non-battery technology and it works very well. Things like taking cement blocks and a crane and stacking to make cement blocks on top of each other, you know, you build up potential energy. When you need it, you run the crane backwards by putting the cement blocks on the ground. Could work, you know. They are trying it in -- trying it out in Sweden. Compressed air energy storage where you put large amounts of air into the ground into a cavern such as abandoned gas wells or oil wells. Thermal systems, including ice, phase change materials, what have you.

Vehicle to grid is a possibility. Dominion Energy, which has a small corner of North Carolina, is experimenting with a fleet of buses. They're going to replace the entire school bus fleet in Virginia by electric buses, and they're going to use the batteries in the electric buses as backup for their system. Okay. I hope to work with them and see how that use case works out.

Lots of interest in long-duration, long-term storage; people looking at eight hours, 12 hours, and even days. If you have a lot of solar, you may want that. Difficult to make a business case here. Will probably need a mandate to make that work.

Hydrogen, ammonia, these things can store energy, too.

So we are winding up. Some resources for you. We are working with the Energy Storage Technology Advance Partnership which has many of the states under its -- under its -- in its group. And we are doing regular webinars in order with the Clean Energy Storage Association. These are available for free to anybody who wants to learn more about the storage. Generally, when we do something new or when a new project comes online, we throw in a webinar and explain it and have the experts in the field explain it. They are -- they are archived. You can look them up on the internet. They are available at all times.

DOE has established and maintains an international energy storage database which has some 2,000 energy storage projects archived there from more than 60 countries. It’s a good resource to look at projects that have actually been built and where they are. Again, it’s free and available on the internet.

Recently, we have started an energy storage policy database where all the states that have policy activities are -- they’re all contained in there. And, again, it’s free and it’s clickable. You just click on the state and say what you want to look at. And the original documents are all in there so you can -- you can access whatever you need.

So with new technologies, I expect cost to go down, and hopefully safety and reliability will increase. With every successful project, the value proposition will continue to be better understood and will increase and, among other things, more jobs here in the U.S. will be created.

Thank you. I appreciate your listening and your interest in the field, and if you have questions, we will be happy to try and answer them.

CHAIR MITCHELL: Questions from Commissioners? Commissioner Hughes.

COMMISSIONER HUGHES: The various costs that you presented, do they include disposal costs, and could you talk a little --

DR. GYUK: In -- generally, no. What you usually hear about is -- well, first of all, when you see that wonderful curve of lithium getting cheaper and cheaper, that's cells only. Okay. It doesn't have the balance of plant and it doesn't have the power of electronics in it. Okay. And those are not going down so fast.

Disposal almost uniformly is not included. Okay. I'm not aware that any company will -- now, they will tell you that, oh, it'll be worked on. I mean, I don't want to badmouth any company. If you find one that gives you a contract and a number, wonderful for them. And I hope in future they will do that routinely.

COMMISSIONER DUFFLEY: So about a year ago I went to an Energy Storage Association meeting, and Lockheed Martin mentioned that they had obtained some patents and were working on a flow battery that contained more environmentally friendly constituents. I didn't hear you mention that, and I was just wondering if you had a status on that.

DR. GYUK: I believe the Lockheed Martin one -- Lockheed Martin was the company that was running Sandia National Laboratory, so I think it goes back to my project or my group's project, vanadium redox battery, which we have -- which we have worked on for almost six years and which is now in a virtually commercial position.

COMMISSIONER DUFFLEY: So it's almost ready to go to market; is that what you're saying?

DR. GYUK: Well, let's put it that way. It already went to market, and then they found some glitches, so it's now being reengineered. And this is true for a lot of different batteries. Okay. I mean, it took lithium ion a long time to get to the market, you know. And it’s nice to get a Nobel Prize for it, but that doesn’t mean it’s perfect.

CHAIR MITCHELL: I think I understood you to say that at this point the resilience benefits associated with energy storage are really unmonetized, but they don’t appear to be unquantifiable, at least in the presentation or in the analysis or examples you’ve walked us through. Is that the case? I mean, if you all are quantifying resilience benefits, could you help us understand how?

DR. GYUK: We try our best.

CHAIR MITCHELL: Okay.

DR. GYUK: Okay. You know, one way to do it would be to say, well, you know, if you ask an insurance company to guarantee that the lights won’t go out, you know, how much -- how much insurance would you have to pay? And can you put in a storage unit for the same amount? And if the answer is yes, then you have successfully monetized it.

But the point is, you know, if you’re talking about, I don’t know, coastal flooding or something like that, you know, if the disaster occurs, it’s a lot, but everybody is figuring, well, it’s not going to hit us yet or I won't be hit or whatever it is. That's why it's so difficult because there's a lot of probability worth into the -- into resilience.

CHAIR MITCHELL: Okay. Thank you. You also mentioned in your presentation discussing sort of the building blocks that are critical for successful deployment of energy storage. And one of them you -- one of them was regulatory -- I'm going to find your exact words -- hang on one second --

DR. GYUK: A benign regulatory environment.

CHAIR MITCHELL: Right. You said something to that effect, but what do you mean by -- how do you define that? What do you mean by it?

DR. GYUK: well, that's basically working out tariffs that are not punitive for storage.

CHAIR MITCHELL: Could you elaborate on that?

DR. GYUK: I suggest you ask that question to Patrick again, but the point is there are situations where -- well, with renewables you know that in general you get tax credits, you get -- you get all kinds of things. With storage you don't. Okay. We had -- one of our early projects we were -- there was a substation. The substation needed to be enlarged. That's expensive. Okay. Because they were customers that were -- that needed more electricity than was coming through the substation.

The trouble is the substation, you basically have to double it. You know, you can't change it incrementally. So what we did -- this was -- this was with AEP -- we suggested putting a megawatt of storage. A megawatt would have covered the extra requirement for, let's say, three to five years and it would have solved the problem, and then if you need yet more, you could eventually build up the substation.

Well, we knew that we had benefits from arbitrage, but we could not count the arbitrage benefits because they were not allowed -- the market did not allow them that. Okay. They could do the -- they could recover expenses from deferring the, you know, deferring the expenses, but not from the arbitrage, so direct payment was not allowed. That's because of the PUC structure. In other places you can.

CHAIR MITCHELL: Okay. Thank you.

DR. GYUK: You want multiple benefits, but you want to make sure that all of those benefits can be charged, or at least as many as you find suitable.

CHAIR MITCHELL: Okay. Any additional questions from Commissioners?

MS. JONES: Hi, Doctor. I've got a quick one for you. On the Sterling, Massachusetts project, if I understood correctly, the grant money was so that -- was to encourage resiliency type projects.

DR. GYUK: Yes.

MS. JONES: And the project ended up making money with arbitrage and with hitting peaks.

DR. GYUK: Yeah.

MS. JONES: So if the project is being run to do that, to do the arbitrage and to clip the peaks off, how could you know that when the tornado comes through and you really need it for resilience that the battery is charged and ready to go, that it hasn't been depleted?

DR. GYUK: They usually tell you a day in advance when the tornado is coming, so you make -- make sure your battery is full. You get all the resiliency benefits. You don't lose any.

MS. JONES: Thank you.

DR. GYUK: But it's a very good question because, you know, you cannot run it blindly. You have to pay attention to what's going on around you.

CHAIR MITCHELL: Okay. Any additional questions from Staff?

(No response.)

CHAIR MITCHELL: Okay.

DR. GYUK: I might add that Staff or Commissioners should feel free to get back to us whenever they please. It doesn't have to be done formally; email, you know. Our interest is to get storage deployed, and if we can help with it, we'll be happy to do that.

CHAIR MITCHELL: Well, thank you very much. And thank you again for being here today. We appreciate your time.

DR. GYUK: My pleasure.

CHAIR MITCHELL: Okay. Mr. Balducci, you are up next.

MR. BALDUCCI: Great. Good afternoon, everyone. Good afternoon, Commissioners. Thank you for inviting me to speak here today. I'm happy to come and present some information on the fundamentals of energy storage valuation, some of the work that we're doing at Pacific Northwest National Laboratory under the leadership of Dr. Imre Gyuk who just spoke.

There are roughly 5,000 employees at the Pacific Northwest National Laboratory out in Oregon and Washington, 5,000 scientists and engineers and support staff. And I lead a team focused on energy storage analytics at PNNL, and you can see some of their names there. They include physicists and economists and several different colors and flavors of engineers. So it's not just me standing -- sitting here before you, but an entire team that I represent, including Kendall Mongird who is turning the slides and is a key contributor on several of the projects that we’re undertaking at the moment.

So we are evaluating energy storage systems in many different forms across the country. The models and methods and tools that we are employing were paid for by the U.S. Department of Energy under Dr. Gyuk’s program, but we are now bringing in much more funding from many different organizations. We've received an enormous amount of interest from states and utilities. Just currently we’re negotiating contracts with five private utilities, and we’re doing work with utilities across the United States presently.

We’re evaluating lithium-ion battery systems, flow battery systems, pumped-storage hydro. We have small-scale pumped-storage hydro, 5 MW, 30 Mwh, at five locations across the United States for Shell Energy North America and we’re evaluating large scale pumped-storage hydro systems, too, one in Wyoming and one in Washington State. And so you can see collectively that we actually have an enormous amount of power and energy capacities for all the different systems that we're currently evaluating.

You can see about 1.6 GW and 18.2 GWh of energy stored at those sites, though as is typical of energy storage system, the vast majority of the power and energy capacity is tied to the two large scale pumped-storage hydro systems that we're evaluating currently.

In addition, we're developing hydrogen evaluation tools for the U.S. Department of Energy and the Massachusetts Clean Energy Center, so taking energy off the grid and transforming it into hydrogen using electrolyzers power-to-gas systems, and then also having the capacity to bring it back into the form of electrical energy through hydrogen fuel cells as well. And all of the sort of transportation uses and industrial gas uses and interactions with the energy markets is built into those tools as well.

We're effectively focused on four sort of sub-thrust areas. The first one is the economic. So we're defining the value associated with energy storage services provided by energy storage systems of all shapes and sizes and chemistries. And we are -- have built these methods, models, and tools in a way that's quite flexible, so they can be applied anywhere in the United States, as Dr. Gyuk correctly mentioned. Markets are fairly straightforward. You have price data, historic price data and forecast price data you can rely on. It’s based on nodes or zones or locational marginal prices. But even if you’re not operating in a market, some unit is providing the same service.

So frequency regulation is being provided by a peaking turbine in many cases, and there’s a marginal cost associated with that, or you have to purchase more capacity resources or resources to demonstrate resource adequacy and there’s a cost associated with that. So these avoided costs can also be modeled, and so using production cost models and relying on Integrated Resource Plans and working with utilities we can define the value associated with all of these services even when operating outside of markets.

In addition to the economics, we’ve done a great deal of work with respect to performance characterization. I’ll get into this in a bit more later. And what we found is that while you may hear that lithium-ion batteries produce 90 and 92 percent roundtrip efficiencies, when deployed out in the field and temperature effects are factored in and it’s AC to AC, so you figure out the losses associated with the power conversion systems and you're engaged in economic operation, so the duty cycles might not be ideal, then the roundtrip efficiencies even for lithium ion can begin to drop into the low 80s and sometimes into the 70s.

The flow battery systems that hold a great deal of promise in terms of reliability and their number of cycles, so their ability to survive for long durations for many years, the round-trip efficiencies are even more -- there's more deviation there and they can actually get down into the 40s in terms of the roundtrip efficiency, which is to say when you charge and discharge the system, under some conditions you could lose 60 percent of the energy in the roundtrip.

So understanding this and then building it into your economic models is extraordinarily important. You don't want to bid into a market thinking you're getting 90 percent roundtrip efficiency when, in fact, you're getting 70 percent roundtrip efficiency. And so we're building all of these lessons into our economic modeling.

The next area is distribution system integration. These energy storage systems don't isolate in a vacuum -- they don't operate isolated in a vacuum, and so you have to factor in their impacts on the distribution system, both positive and negative. So there's improvements in resiliency, which for short duration outages we do monetize. There's also improvements in terms of hosting capacity for DERs and photovoltaic and solar units, but there could be cost as well because if you discharge a system fully, the feeders may or may not be able to actually accommodate the full discharge power of the energy storage system, and so all of this has to be accounted for.

And then the last area is controls. And so, you know, all the modeling work that we do and all the simulations and all the economic assessments are really planning tools. I mean, effectively we're defining what we expect the values to be. We simulate their operations. We try to make them as realistic as possible. We've built in uncertainty, imperfect foresight with respect to prices, but the reality is, is that in real-time it's more complicated, and so capturing those values in real-time requires tools and control systems and so we help in the development of those as well. So we've developed a taxonomy of energy storage values.

And do please feel free to interrupt me at any time if you have specific questions for each slide. And so, you know, I was speaking with one of the Commissioners before the hearing, and he raised the question of distribution level value. And you're quite right, most integrated resource planning processes, of course, don't include distribution level values or don't accurately capture them through that process, but they are significant value, and they include benefits like deferring investments in distribution systems, improving resiliency, reducing outages, and also improving the efficiency of the distribution system through Volt-VAR control or conservation voltage regulation. You can obtain both real and reactive power from energy storage systems so they can effectively, you know, improve the efficiency of the distribution system.

Similarly, at the transmission system, just like in the case of Nantucket Island, there can be huge benefits associated with deferring investment and transmission assets like transmission cables, and then also in reducing congestion. As each of you probably know, in markets, congestion is built into the price of energy, so to the extent that you're relieving congestion along transmission networks, it allows power from throughout the region to get to where it needs to be with less limitations and at lower cost. And so that can drive down cost throughout the region by alleviating congestion along transmission corridors.

Bulk energy services, including capacity or resource adequacy, and energy arbitrage which is, of course, buying low and selling high in energy markets.

And then there’s all the ancillary services engaged in trading in market operations, including regulation, load following, spin/non-spin reserve, the standby reserves, and black start service, voltage support, and those sorts of services.

Once again, even if operating outside of a market, there is a cost associated with providing each of these services to the utilities operating in your state. And there are models, production cost models and capacity expansion planning tools and other models that can be utilized to assign a value in terms of avoided cost for each of these services.

And then finally, behind the meter we have customer services. Shifting of energy can result in reduced demand changes, reduced time of use pricing and, of course, outage cost reduction as well.

So we’ve conducted an extensive literature review, about 40 to 50 studies of energy storage across the United States, and we published this in the Energy and Environmental Science Journal about a year ago. And what we see here is that these values do vary greatly from one location to the next, and so these values are not uniform. The value here in North Carolina would be quite different than the values that are evident in the Pacific Northwest or in California or New York or New England, depending on the availability of resources and, of course, the profile of the generation fleet, load-shifting patterns, the extent to which renewables, intermittent renewables are expanding in your area.

In a place like the Pacific Northwest we have very high renewable portfolio standards, but we have legacy hydro, and so that legacy hydro drives down our cost because it adds a great deal of flexibility and low-cost generation capacity. But as those renewable portfolio standards begin to impact our utility investment decisions, as they will be in the coming years -- Washington is going to a hundred percent RPS, and California is, and Oregon’s is quite high as well -- then on the margin, these investment decisions will be much more expensive. You can’t just simply rely on the legacy low-cost hydro.

And so higher cost renewables will come into the fold, and then the intermittency associated with that will generate balancing requirements -- we'll get more into that in a few moments -- but those costs can be quite significant as well. And so even in one location they change over time.

In California you're probably aware of the so-called duck curve. And so as the net load, you know, soars in the afternoon, effectively there are these significant ramping requirements, and battery storage systems have been mandated for addressing that and there is a new market product, the flexible ramping product, that is generating significant opportunity and cost in that region as well. So it varies by location.

And we can see that although arbitrage was the first use case defined for energy storage system, it makes the most sense, it tends to be one of the lowest value of all the use cases for energy storage systems.

Frequency regulation is a higher value stream for energy storage systems. And what we find is that transmission and distribution deferral is extraordinarily variable, but can be enormous locationally, but in many locations is of very little value. Next slide.

So now I'm going to go through several of the use cases and effectively how we assign value to each of them.

So for capacity or resource adequacy, effectively, this is ensuring that you have enough power throughout the year to meet peak loads, plus a reserve requirement. Capacity markets have been established in several regions throughout the United States, including California and New England, and so through a forward-capacity auction and then ultimately a forward-capacity market, the prices are set.

Note that, you know, energy storage systems are very effective at addressing both capacity and frequency regulation, and so when market prices are high, sometimes energy storage services systems and new operators of generators can actually be victims of their own success because as they bid into these markets to absorb these high prices, the supply curve shifts outward, the new market equilibrium price falls significantly, and effectively the bottom can fall out of these markets. So for a place like ISO New England, it was trading at roughly $11 per kW per month, and then many more generators and energy storage systems entered the market, and the market has recently crashed down to about $3.80 per kW per month.

Now, for the regulated utilities, the vertically integrated investor-owned utilities, this is capacity based on the cost of a new entrant or the next best alternative which tends to be a peaking combustion turbine. Now, those turbines cost about 150 to 200 kW -- dollars per kW per year, but you back out the flexibility services associated with them, and then you have to determine through a loss of load probability analysis the incremental capacity equivalent of a battery system. Know that it's not as capable of providing capacity as, say, a traditional generator.

So if you have an energy-to-power ratio of say 2, and you only have to cover four hours, you're only going to capture half or less than half, potentially, of the value. So if the value is trading at $120 per kW per year, a two-hour battery may only capture $60 of that because it's not going to be quite as reliable as a generator. Once again, it's -- it may not be fully charged when called upon as necessary, and its energy-to-power ratio only allows it to ride through for a couple of hours, and you have to account for all of that. And typically it's done through a testing process or through the IRP process. Effectively, the incremental capacity equivalent is defined.

The second use case is frequency regulation. Energy storage, of course, starts here through FERC Order

755, the Pay for Performance Order. The full value of energy storage was captured because there's a performance component. And to the extent the generator cannot provide the services effectively as the energy storage system, the value is derated; whereas, an energy storage system usually captures 95 percent plus of the benefit.

And in addition to the capacity that's bid into the market for the hour, there's a mileage or service component. So as energy is cycling in and out of the battery system, think of it as string that's moving up and down and then you pull the string taut, all of the energy passing into and out of the system, the energy storage system, is compensated for that as well. So it's effectively the summation of all the green bars in the chart that you can see there.

And once again, in PJM there was a REG-A and REG-D signal that the energy storage systems followed quite successfully, and some of the early entrants made a great return on investment, but once again the PJM market collapsed. And then the AGC signal was altered by PJM in a way that has led to excessive degradation of the energy storage systems, and so the return on investment for new entrants is not nearly as promising as for old.

And so that's a challenge for energy storage systems. You know, they’re looking at current market conditions, trying to predict the future to the extent that long-duration contracts are through an integrated resource planning process that can capture not only the marginal value, but the long-term value of driving down the cost associated with the frequency regulation is a -- is a great value to the energy storage providers or the utilities purchasing energy storage systems.

The next benefit stream is renewable energy time shift and capacity firming. I already mentioned the CAISO duck curve. CAISO has implemented a ramping product, because as all the solar comes offline in the early evening and then folks come home and turn on their lights and their appliances, we’re seeing the net load curve thrust upward quite quickly.

And so what CAISO realized was that through traditional capacity, plus frequency regulation and standby resources, that these resources collectively might not have the ramping capability required to respond to such an extreme event that was actually taking place, you know, every day, every weekday during the summer months. And so they implemented a flexible ramping product that allows the bidder to not only bid in the price of providing the service, but also the ramp rate, so the megawatts per minute that they can actually ramp up.

And so all of this is taken into account through this product, and effectively a demand curve for this extreme ramping capability is developed on a -- in a real-time basis, and it’s a real-time market at five and 15 minutes. And so that’s a significant cost.

You know, we found that through a national study that we performed for Dr. Gyuk there, that for every, you know, megawatt of renewables that you put on a system -- or excuse me -- for every 6 MW of renewables that you on a system, it required 1 MW of balancing. And so when you’re comparing the cost of solar to a traditional generator, that’s not exactly an apples-to-apples comparison because the intermittency associated with renewables carries cost associated with that. And so energy storage systems provide significant value in this regard.

We evaluated nationwide. It was a 6 to 1 ratio. But then on the margin, because there’s existing balancing capacity, it was a 10 to 1 ratio. So for new wind and solar coming on the system, and this is national, we did evaluate it at a regional level, you know, and I can provide that report to you, so it will differ from one region to the next, but nationally it was a 6 to 1 and 10 to 1 ratio.

And then, of course, renewable energy capacity firming. There are some areas placing ramp rate limitations. And I can tell you in the Pacific Northwest that if you interconnect to the Bonneville Power Administration transmission lines, you have to pay $15 per Mwh in firming cost because of the intermittency associated with that. And you can see the line without energy storage, and then -- and then with it, if you can add it. Effectively, it can smooth out the intermittency associated with the generation, renewable generation, and there's a significant value associated with that.

Okay. The next benefit is outage mitigation. We can measure this from the perspective of the utility or from the perspective of the utility's customers. And when we evaluate it from the perspective of the customers, it's in terms of what's called value of lost load. And so when the lights go out, it doesn't mean much to residential customers, about 3 to $4 per hour, on average, based on interruption cost studies performed by the Lawrence Berkeley National Laboratories. Small commercial industrial customers a bit more. Effectively, they have to, you know, turn down their ovens and turn off their lights and they lose their customers that are restaurants. But for large commercial industrial it can be tens of thousands of dollars, as high as $150,000 per hour on some of the cases that we've evaluated. So significant value associated with loss of load.

And what we'll do is we will model it with perfect foreknowledge and with no foreknowledge. So without foreknowledge we would be operating in, you know, all of our various use cases, and then whatever energy happens to be available in the energy storage system on a -- at a time when the outage strikes, and we -- in our simulations we place the outages based on the value of lost load for the customers that could be islanded with this -- with this energy storage system, and then also based on historical data around outages.

So on Nantucket Island there were 704 outages over 10 years, so there it was a significant benefit stream. Elsewhere, it's often, say, two to three outages per year on a typical feeder, and we can effectively create a statistically average year of outages.

Then we place those randomly throughout the year, and then our model simulations attempt to address them. And then we evaluate the value or the cost of the outage with and without the energy storage system and look at the change in terms of the value of lost load to those customers.

The problem with resiliency and the reason why it’s not well known is that there are enormous costs when there are long duration outages. An entire community ceases to function. So there are direct -- indirect and induced economic effects associated with all of the factories shutting down or all of the businesses shutting down. But there’s also risk to life. There’s the value of a statistical life. There's injuries that take place. There are public safety concerns.

And so, you know, the way we think about this, at least when I’ve written about this, what I have suggested is that it should be unexpected value analysis. So it’s a multi-hazard risk assessment. What are all the things that could go wrong and what are the full costs associated with each of those things? So we’re doing something like this for a study in Eugene, Oregon, but it’s quite incomplete because of the ability of the energy storage system to keep the operations center open and how that changes the outage duration, and who is affected under these multiple hazard assessments is incredibly complicated, and the utility doesn’t have good answers for that. No one does, really. And I know there's a project at Sandia National Laboratories under Dr. Gyuk's leadership, attempting to assign some values to these key elements.

But for the Eugene system, you know, we're looking at snow and ice, so on an average year there's about 120 percent chance. So on average there would be 1.2 events that would cause sort of catastrophic outages for this Eugene Modern Electric Board. With respect to flooding, it's a very low probability for Eugene. And then there's the Cascadia subduction zone earthquake event that would be incredibly disastrous for the region.

But then the ability of the energy storage system to keep the operation center open and its impact under such an extreme scenario is quite challenging to estimate, but we do have reasonable estimates, something like one-tenth to one-fourth of 1 percent on an annual basis of one of those catastrophic earthquakes hitting Eugene. And so we're digging into it, but assigning a full value associated with that is quite challenging.

Okay. The next slide is transmission and distribution deferral. And effectively, you know, if you defer an investment in a transmission line or a distribution substation, you know, it's going to be about 2 percent more costly each year, so if you defer investment in it, it's going to be a bit more expensive 10 years from now, you know, 1.02 raised to the 10th power. But when accounting for it from a utility perspective, and the denominator of the present value perspective is something more like 1.06, it's going to be based on their weighted cost of capital which is going to be closer to 6 or 7 percent. So it's 1.06 raised to the 10th power.

And so we evaluated a distribution substation, and we can see here that effectively by deferring investment in this distribution substation by six years, it reduced its cost by about 25 percent from 10 to 7.5 million. And for the submarine cable for Nantucket Island it was closer to $110 million because it was roughly a $200 million dollar investment that you could defer for 13 years.

So that is highly location specific. In the majority of cases there is zero value associated with distribution or transmission value, but for a select number of locations it is the number one use case and of enormous value. We usually go through a screening process, that there's 10 or 12 potential investments that you can defer at the transmission and distribution level, and this is how you defer it, does it apply here. And most of the time it doesn't, but in some instances it's a significant value. And, of course, this wouldn't be captured in a traditional planning process, integrated resource planning process. And so it's important to think of these values more broadly.

Now, I've gone through all these use cases, but you can't simply evaluate them individually and then add them all together. You have to simulate operation of the battery system. Effectively, there's multidimensional competition for the energy in the storage system. If you use it in this hour, there's less of it available in the next hour and the hours that follow, and then you cannot provide all services simultaneously. Sometimes you can provide -- you can meet the needs of multiple services in a given hour, but in many cases you cannot. And so, you know, what we find is that, you know, when consultants evaluate the benefits individually and add them together, you're typically overstating benefits by roughly 30 percent.

Another thing we do is we don't assume perfect foresight with respect to prices or with respect to load and conditions. We assume imperfect foresight, and then we predict what those prices will be, but then use the actual prices for the clearing process. We find you typically get an additional 10 to 15 percent of the value when you do that. And so, you know, these additional analytical steps are required to produce defensible, scientifically defensible, and I think realistic numbers.

And so you can see here in this chart here to the left, the energy prices in the first panel, if all you were doing was buying low and selling high, in the energy market you can see the duty cycle there for the 5 MW battery system. In the early morning hours it's charging. That's why it's negative. You're pulling energy off the grid. And then around lunchtime and in the -- in the evening hours you're discharging to take advantage of higher prices during those hours.

But then as you layer in each additional benefit, balancing distribution deferral and Volt/VAR control, the signal or charging and discharging duty cycle changes, and so this is what the battery system would be doing to optimally engage in economic operation. And you can see that once it does that, some of the arbitrage benefits would effectively melt away at that point because you can no longer capture those. You are chasing higher value frequency regulation benefits.

And effectively, what our models will do is effectively have a running ticker each hour of the value

-- a buy value stream that it's being generated, and at the end of the year tell you the number of hours you would be optimally engaged in the provision of each service and the value providing each of those services.

So the first case study I want to run through is the Salem Smart Power Center. This was a shovel-ready project that was funded under ARRA. At the time it was extraordinarily expensive, about $20 million plus. And when you built in all the rate impacts, if it were to have been built into the rates, it would have been closer $28 million. The cost of it today would be much lower, closer to, I think, 6 or $7 million, so that shows you the significant degree to which we have been successful at reducing the prices associated with, particularly, lithium-ion battery systems.

Also, there were some components associated with this project, you know, a $3 million building that today would be unnecessary. And so even with respect to the power conversion systems, the balance of plant and the interconnection costs, some of those costs have been coming down, but not to the degree to which the battery system costs have been coming down.

So you can see here it was a 5 MW 1.25 Mwh system, so an incredibly shallow system with an energy-to-power ratio of 0.25. It was to act as a -- the provision of ride-through capacity in a high-reliability zone to aid in the elimination of outages for a few high-value customers, including a call center and the headquarters of the local National Guard.

The utility identified a whole host of potential use cases, but after we evaluated those use cases, we broke them down to nine specific use cases and then, in truth, there were fewer than that that were of real value to the system. And so despite the fact that we may have 15 to 20 use cases defined, typically the number of use cases evaluated for each system is more in the three to seven range. You can't simply -- once you start providing more than that, it gets sliced quite thinly and there's very little value that's remaining.

Now, what you'll see here is that if you simply added all the benefits together, you would generate about seven and half million, but when co-optimized, so effectively simulating operation only taking advantage of the technically achievable benefits, it falls to 5.8 million, so you can see that it's a much lower value.

The energy or the return on investment ratio was quite low given the very high cost of the system, but if you're investing today at the relatively lower costs that are evident in the marketplace, you could, if sized correctly, generate a positive return on investment ratio. And so one of the points we make here is that it's important to fully evaluate the technical potential and the economic potential of an energy storage system prior to deployment, prior to design, because as you can see here, even with today's prices the return on investment ratio was below 1, at about, I think, .78, but if sized correctly with an energy-to-power ratio of 2.0, they could have yielded a positive return on investment at 1.24.

Effectively, at 0.25 there's such limited energy that it really can't serve in the provision of ancillary services. It has very little energy to provide frequency regulation or spin on spin reserve. It cannot provide hardly any capacity if it's a four-hour product, for example. I mean, effectively you'd have to divide the benefit by 16 in this case to make it an incremental capacity equivalent. And so that has to be worked through and should be worked through by the utilities prior to building it into an Integrated Resource Plan or deploying or designing the system.

So the Nantucket Island Energy Storage System Dr. Gyuk already highlighted, and I will get into quite a bit more detail here.

It’s a small resident population of about 11,000. It’s a playground for the rich during the summer months and the load soars to 50,000 for about -- 50,000 MW during about a two-month period. But it’s really just a 2 to 300-hour period where you really have to focus to ensure that the N-1 contingency requirement is met.

And so it’s -- rather than investing in a third cable that could cost upwards of $200 million, an energy storage system can provide that capacity, in this case combined with a combustion turbine generator can provide that service, but then be freed for the other 8,560 hours in the year to perform other services. And so it was just a very unique and powerful opportunity here for energy storage. And so we evaluated a small number of nonmarket and market operations to a very successful degree in this case.

So the benefits of local operations, you can see here to the right that we modeled load and then predicted load out into the future, projected it out into the future for a number of years. And so the load is evaluated in sort of an extreme scenario as sort of a 95 percentile extreme scenario so that ensuring that we’re quite conservative.

What we found that basically in this year, the first year in which the load would be expected to exceed the N-1 contingency without the availability of the energy storage system and that it would only require energy from the battery system for four hours this year. And then in future years we projected and then predicted the hours during which the energy storage system would need to be available to ensure that you're meeting that N-1 contingency scenario.

So with that analysis and then projecting into the future, you can see the number of deferral years estimated at 13. The benefits of local operations was estimated at 122 million. Most of that was the transmission deferral benefit, but the other was outage mitigation, 704 outages over 10 years. We went through a screening process and reduced all the outages that the energy storage system could not mitigate, and that actually eliminated something like 80 percent of the outages. We broke it down to a smaller number. We modeled the entire distribution system for Nantucket Island and then simulated the relevant outages with and without the availability of energy storage.

And so we could show that under ideal circumstances, that the battery system could eliminate roughly 46 percent of the customer minutes of interruption on that island, so an enormous benefit. Now, I say ideal because when we performed the distribution system analysis, we learned two things. One is that you could not fully export both the combustion turbine generator and energy storage system power simultaneously. You would effectively overwhelm some of the lines on the island. So we could target specific investments in reconductoring to enable the full discharge of the systems. And then the other thing was that all the switching on the island had to take place manually. And so we take about an hour to do all of that, and through some automated switching you could reduce that to five and potentially one minute of outage before all the power is restored. And so an enormous benefit in terms of showing the value of each of those investments and the costs of them, showing that you could effectively improve the economics by about 2 to $300,000 annually through those investments which, of course, were quite a bit lower than that, so a significant value.

Now, in addition to nonmarket operations, National Grid wants to engage in market operations, so some of you may rightly be recognizing that if they rate based this asset, which they did, that currently they would not be allowed to also participate in the energy markets. But FERC has issued a memorandum suggesting that it was open to operating rate-based assets in energy markets and encouraging utilities to propose the use of such systems in energy markets. And so National Grid wants to use this as a test case and be the first one to take advantage of this opportunity, then pull those benefits back to their customers because the reality is, is that they only need this asset for a very limited number of hours each year.

For those of you who are also well schooled in how markets operate, you’ll also recognize that you can’t toggle into and out of markets. That’s not allowed, and you could face penalties for effectively what’s called economic withholding. But through a combination of rules and ISO New England, they can use this system to provide local reliability services and establish an opportunity cost associated with not providing that service, build that into their price and effectively make the battery system economically unattractive to ISO New England. That’s all perfectly legal. And we’re confident that if they can predict when the N-1 contingency scenarios will be occurring, that effectively they could pull the system back for providing that service.

The other thing is in response to FERC Order 841, ISO New England is now offering something called a CSF. And so this is a storage facility, a continuous storage facility that acts as a generator would, as a demand-side resource would, or as a regulating resource would. So in markets across America, some of the complaints are that energy storage systems are treated like any other generator, but they have unique attributes.

So, for example, an energy storage system, if it's a 10 MW system, it can provide the full 10 MW of regulating capacity because it can go 10 MW up and 10 MW down, whereas a generator cannot. It effectively would have to provide, you know, 5 MW up and 5 MW down. It has to function at the 5 MW level of output and then cycle up or down. But an energy storage system can provide twice the regulating capability. It also can respond to the subsecond level, so it’s always spinning, effectively, so it should be available for providing that spinning reserve as well.

And so you can see these three signals here in the top graph to the right, that if it was providing services as a generator, you can see it discharging there. If it’s responding to as a demand-side resource, you can see it absorbing energy down. And then in ISO New England it can also follow an energy-neutral AGC signal, and that's the one that's cycling up and down. And those are all combined into a single signal and it's compensated for all three market services. And so we bid into that system.

So in the next slide you'll see when it's all added together, it's $146 million in present value benefits, revenue requirements of the combustion turbine generator plus the battery system. The battery system was 6 MW, 48 Mwh system, at a cost of about $31 million. It's a Tesla battery system. The full revenue requirements are about $94 million, with a return on investment ratio of 1.55.

So if you go to the next slide, you'll see the results of several of our recent studies. You can see the Salem Smart Power Center and how, as currently constructed, that didn't function well. With the PSE Glacier, the return on investment from the perspective of the utility was quite poor at about 0.44, but when you built in the value of lost load, it was an isolated community with poor reliability in a mountain near the Canadian border, and it almost penciled out at that point. It really provided a great service, and there demonstrated the capacity to island the entire downtown core of that very small city. It's about 30 businesses and about 40 residential customers, but the battery can do that. It can effectively isolate an entire community or a large segment of Nantucket Island in this case.

For OPALCO Decatur Island we're evaluating the deferral benefits associated with reducing stress placed on a submarine transmission cable. So this is a $40 million cable, and effectively during peak periods we can reduce voltages and stress placed on that cable. And we built an electrothermal model to evaluate the benefits of doing so, and by doing so you can defer investment in that cable by about four years. And so those are enormous cost assets, and so a great value there.

And then Avista Turner, I'll call your attention to that. That is Schweitzer Engineering Laboratories. It would be located effectively in the parking lot of that facility. And when there's a voltage sag of a significant enough degree and duration, the machines shut off, and once they're off, they're off for three hours minimum. And the cost of that is $150,000 an hour, and that takes place about twice a year on average, plus there's -- even though they have two feeders serving that site, there is an outage about every two to three years, and so enormous savings to that high-end manufacturer.

So moving on to the cost of storage, you've heard about the lithium-ion prices and how they've been falling. You know, with lithium ion, it's being deployed in the consumer electronics area, in the automotive area, and less so in the grid space, but because of those advancements that are taking place, the manufacturing and technology and the resource appropriation, the costs have fallen significantly. And so you can see the costs falling below, for an entire pack, below $200 per kWh in energy capacity. So if you have a 1,000 kWh or 1 Mwh system, the cost of that would be -- would be $200,000 in this case.

But that's only roughly half of the cost. There's also power -- a conversion system cost or the inverter shifting the energy back and forth between AC and DC, and then the balance of plant cost and then the construction and commissioning cost. You still have to build a concrete pad if you don't place it in an existing substation or an existing building site. You still have to build a fence. You still have to get the finance team involved, the lawyers, the engineers. You have to interconnect it. You have to control it. And all of those have costs, and those costs aren't falling as quickly as the costs associated with the battery systems.

Kendall there, Kendall Mongird, recently led a study to evaluate the cost associated with six battery chemistries broken out by those four components that I just mentioned, and then also for non-battery technologies, including pumped-storage hydro, compressed air energy storage system, ultracapacitors, and one other which I'm sure I'll remember in a moment. But, you know, what we find is that, of course, lithium ion is the least cost technology at this point for a 1 MW, 4 Mwh system. You would expect to pay roughly, you know, 4 to $500 per kWh all-in cost.

But you'll see there two things. You know, first of all, the roundtrip efficiency, it's higher than the other technologies, so it's functioning very well, but it also degrades quite a bit quicker, and if you don't -- if you're not careful in how you operate the system, it can degrade quite quickly. If you operate it efficiently, it will degrade at about one-half of 1 percent annually. And its life cycle -- its life is only about 10 years, and that's under sort of the best possible conditions. Sometimes you'll get a 20-year warranty, but when that takes place it's because there's effectively interim investments that are included in that, so they have to effectively address the degradation throughout the life of the unit and replace the entire battery pack after 10 years, typically. And so some of that is built into those contracts that you receive.

For a flow battery system, you know, effectively, you know, there's electrolyte in big tanks, so if you're talking about a long duration storage battery system, it is very promising because you just have to make the tanks larger, more electrolyte, you know, passing by a membrane that is, you know, effectively energizing the electrolyte, and so you can scale it at a very low cost. But its base system cost is much higher. Also, its roundtrip efficiency is lower and more variable than lithium-ion battery system costs, so that's a concern as well.

With respect to pumped-storage hydro, I would mention that, you know, this is 97 percent of the energy storage capacity. Worldwide, these tend to be enormous systems, very low cost in terms of the dollars per kWh at about 165. The energy-to-power ratio tends to be much higher, you know, something like 10 to 16 to 1. They can -- they can operate for 50 years in some cases so they're a very long-lived asset, but they are enormously expensive, in the billions of dollars in terms of cost.

And so there have been no new large scale pumped-storage hydro units built in the U.S. in the past 20 years. And there are significant permitting requirements if it’s an open-loop system because it’s interacting with the natural environment, and that is enormously expensive. And so because it’s not providing baseload energy, it’s difficult to demonstrate and ensure the value of the system.

In addition to all the valuation and the cost analysis that we’re doing, we’re also conducting extensive battery testing at Pacific Northwest National Laboratory. Typically, we start with electricity prices and very specific conditions at a site, build in the energy storage specifications, and we develop a series of duty cycles that mirror the economic operation of the battery system. So what does arbitrage look like at this site for this system? What does the frequency regulation look like? You know, what does capacity -- the provision of capacity services look like for this energy storage system at this location?

We go through the DOE -- OE test protocol, then we mirror the economic operation, go back through the test protocol sometimes multiple times. We collect 80 to

140 data tags per second in some cases, pass through a filter where we’re monitoring performance, and effectively we have a number of parameters that we’re monitoring and our coefficients for each of those parameters and how they affect roundtrip efficiency and the state of health of the battery system is updated continuously. And so we can predict with great accuracy how different types of battery systems can perform, and they perform quite a bit differently than you would expect based on manufacturer specification and what you read in industry literature.

So the next slide, Kendall. You'll see that we recently evaluated four battery systems through the Clean Energy Fund. Two were vanadium flow battery systems, a technology that was developed at Pacific Northwest National Laboratory and then was commercialized through the UniEnergy Technologies' systems, and then two lithium-ion battery systems, systems as small as 1 Mwh, expanding out to 8 Mwh in energy-to-power ratios from 0.5 to 3.6.

The roundtrip efficiencies for the flow battery systems were lower than the flow -- than that measured for the lithium-ion battery systems and much less variable, so we’ll get on to that in a bit more in a moment, but -- whereas, the lithium-ion battery systems typically are in the high 70s to low 90s in terms of the roundtrip efficiencies, the flow battery systems, in fact, did fall into the 40s and 50s in terms of their roundtrip efficiency based on how you're operating it.

So not only did the roundtrip efficiency differ by chemistry, it will differ by duty cycle for the same battery system. So for the Puget Sound Energy Glacier lithium-ion battery system, basically these are the roundtrip efficiencies. Each one of these little boxes represent one week of testing in each of the various use cases.

So for the lithium-ion battery system, as the temperatures began to fall, you can see that the roundtrip efficiencies also fell. And then depending on the use cases, it varied quite a bit. So if there were significant standby between the charging and discharging, then it absorbed more standby losses. If the power output level was quite low, then the auxiliary loads were a larger share of the overall calculation. And so these were some of the factors that influenced the roundtrip efficiency factors.

So we've built this all into a single tool, and what you'll see there in that chart to the right is as --

the lines converge over time, so when we initially started testing battery systems, we would build duty cycles for a one-week period, and then within two days we would be outside of state of charge limitations. We'd have to stop the testing and restart it after calibrating to get the battery back to the state of charge that we had expected.

After we developed this model and started using it, then we found that we could go weeks without having to recalibrate. And even if we were engaged in a very complex duty cycle with a significant degree of ramping, we could predict it quite accurately. We've also found that this capability has allowed us to greatly enhance the value from the services provided by the energy storage system.

When it's charged, we charged it in the most efficient way possible, and when we discharge, we know exactly the roundtrip efficiency for each of our market and nonmarket operations so we're not blindsided by poor performance.

And effectively, the four -- the four variables that were statistically significant in terms of influencing roundtrip efficiency are power output level, temperature, the state of charge range within which you're operating, and whether you're charging or discharging. And then over time, of course, degradation also influences it.

So in this slide, effectively, as you can see here, that for this one test for arbitrage, it was very low value stream, but, you know, we obtained up to 50 percent more revenue when we could correctly predict the performance of the battery system. So without enhanced operational knowledge we were all over the place in terms of operation, so we're bidding it in thinking we're getting 90 and we're only getting 65.

And so with that enhanced operational knowledge we really reduced the charging cost and could bid it into the system more cost effectively. Even for a system operating outside of the markets, you'll greatly enhance the value with a -- with a large degree of real-time operational knowledge. And we found that this value proposition is even more enhanced through knowledge of degradation. So we're going to be publishing something very soon covering state of health. And what we found there is that state of health matters a great deal. If you over exercise the battery, you'll burn it out in three or four years. So either you can operate it within the limitations of the manufacturer's warranty -- that's one way to limit degradation -- the other way is enhanced operational knowledge. So with enhanced operational knowledge you could push it a bit to obtain the maximum amount of value, while not degrading the operation capability of the system.

Let’s skip ahead two slides, Kendall, please. With respect to our controls work, I just wanted to mention the optimization performance evaluation tool. It’s like a Monday morning quarterback. You operate the battery system for a month. We then re-operate it for another month and first simulate its operation and see how much better we can do. And what we found is that we can do typically much, much better than you did with your control system for three reasons.

One is a prediction error. If you haven’t built in prediction properly into your accounting -- so you’re bidding it in, making some grand assumptions about prices or not properly accounting for prices, you’re probably getting it wrong. If you don’t have enhanced operational knowledge associated with your system, you may think you’re getting 90 percent when you’re getting much lower than that.

And another thing is there’s often a significatory of logic errors built in. You know, for a utility in the Pacific Northwest they were using a battery system to minimize these balancing payments that they were paying to the Bonneville Power Administration to avoid what were in most cases 10 percent penalties for provision of balancing service, but absorbing 30 percent roundtrip efficiency losses when doing so, so -- taking 30 percent losses to avoid a 10 percent penalty is not a sound economic decision, and so our tool could catch that and their control system didn’t, didn't capture it.

So, you know, what we’ve learned is that siting and sizing of energy storage system is incredibly important. The consideration of a broad set of use cases capturing, you know, optimal set of use cases, while accounting for uncertainty, and accounting for co-optimization based on the utility structure, the benefits will vary quite considerably if you’re operating in and out of the market, and then battery characteristics is important to capture those battery characteristics correctly and efficiently.

Now, the future of energy storage at PNNL, under the leadership of Dr. Gyuk and the Department of Energy, we’re expanding our models to include many forms of energy storage, including non-battery storage. We hope to work with Sandia National Laboratories and EPRI to have a standard valuation -- industry standard valuation model. We now have our competing models and we'd like to have some collaboration there.

We're going to be developing optimal siting and sizing of energy storage and balancing areas, so when trying to answer the question how much and where for a given balancing area, balancing authority, we're going to be working on that over the next couple of years to have a model to enable that -- utilities to answer that question, increasing the performance, safety, and reliability of grid-scale storage.

And then with respect to our policy work -- this is the equitable regulatory treatment -- we're working with states like Hawaii, Nevada, Oregon, and Washington, and addressing some of their challenges, while implementing mandates and new legislative requirements. We've built the DOE Energy Storage Policy Database and we're developing an evaluation handbook, all supporting Dr. Gyuk's program.

And then finally I'd like to acknowledge Dr. Gyuk and Bob Kirchmeier who leads the Clean Energy Fund work. I'll be meeting with your staff this afternoon and my contact information is on the final slides.

And I have a few minutes, and I'd be happy to take any questions you have.

CHAIR MITCHELL: Thank you very much, Mr. Balducci. That was very helpful information you shared with us. Are there any questions from Commissioners? Commission Staff?

MR. BALDUCCI: We do have a few minutes, so --

MS. JONES: And it's Public Staff that you're going to be meeting with --

MR. BALDUCCI: Yeah. I'm quite happy to --

MS. JONES: -- when we're done. Help me understand the one chart -- let's see -- page 26, I think, seems to indicate that when ambient temperature is high, the battery efficiency is high. Am I getting that right?

MR. BALDUCCI: Let me see here. So -- which number is that? That's --

MS. JONES: Twenty-four (24). I'm sorry.

MR. BALDUCCI: Twenty-four (24). Okay. So let's see here. Yes. The temperature -- did I say the reverse? I thought I said as the temperatures fall, yeah. Yeah. So as the temperature -- lithium-ion battery systems perform well under higher temperatures to a point, but they also have HVAC systems that allow them to keep them from overheating and then had draws on energy, of course. But up to a point they can -- yeah, it would typically -- yeah.

MS. JONES: So how high is high? And if you could help us understand, I mean, North Carolina is sort of known for long, hot, humid summers.

MR. BALDUCCI: Right. Uh-huh.

MS. JONES: Is that a good thing or is that a bad thing?

MR. BALDUCCI: I think it would be a good thing up to a point, but it could ultimately be a bad thing. Now, if the -- if the -- if my staff who work on this were here, they could answer this question more intelligently. But I will tell you this, that the temperature at this site I don't think ever went above, and this is the temperature in Celsius there, so I don't think it ever went above the low 80s. So this is on the Canadian border here, so there were very few cases where if it approaches a hundred, and I'm speaking a bit out of turn, but I would expect the roundtrip efficiency to fall as the HVAC systems kick into a higher gear to ensure that you maintain a satisfactory cooling level for those. The auxiliary loads would rise.

And so there's chemistry effects that are improving their roundtrip efficiency, but then there's going to be thermal effects that I think drive it down ultimately once you get into those very high temperatures. I think that's what they would tell you. Yeah. But we never -- we never reached them there.

MS. JONES: Sure.

MR. BALDUCCI: This was North Washington State on the Canadian border, effectively.

And the other thing I was going to say -- so let me make sure I cover this. So some of the barriers -- you asked a question of Dr. Gyuk and he said ask Patrick, but so with respect to states, you know, with Integrated Resource Planning processes, you know, they're not capturing sub-hourly benefits. Oftentimes they're not capturing locational benefits as well. So either it's being treated as a distribution asset and it's comparing this to, let's say, a substation upgrade, you know, a new transformer or something, but not capturing all of the system level benefits that it can provide. Or in the IRP it's capturing all of the system level benefits, but not any of the location-specific benefits. And also from state to state the interconnection standards can differ quite significantly and there can be barriers there.

With respect to markets, once again, you know, the question is, is it a generator, is it a demand-side resource, is it a regulating resource, and the answer is, yes, it's all of those things. It can provide all of them. It has to demonstrate the capacity to provide all of those services, and there are ways to do it, and FERC 841 is now requiring it of all the regulated markets throughout the United States.

Also, there can be sort of high thresholds, so you can't bid into the market unless you have 1 MW or 2 MW of capacity. And, of course, there are smaller battery systems that are yielding location-specific benefits that could also provide market-level benefits, but it's -- but it cannot participate because of the requirements of the system, the sort of threshold levels.

And then once again, if it's rate based, then FERC historically has not allowed for market participation, despite the fact that it may only be required for the specific service there locally very infrequently. So if it can demonstrate its ability to provide that local -- location-specific service and bid into the market, so you have to do any sort of deration through a performance test or something, it should be allowed to get into those markets. And so With Nantucket Island sort of leading the way, utilities are very interested in pursuing that.

CHAIR MITCHELL: Commissioner Clodfelter.

COMMISSIONER CLODFELTER: I'm going to give this a try, and we'll see if I can get it out. Sort of a summary type question for you, and it's going to be a specific case, our case.

MR. BALDUCCI: Yes.

COMMISSIONER CLODFELTER: Okay. So I'll get to the question, but let me sort of lay out the parameters first of sort of what the case entails. Say we've got just south of 4 GW of installed or interconnected PV solar third-party owned, third-party operated.

MR. BALDUCCI: Uh-huh.

COMMISSIONER CLODFELTER: The grid owner and operator does not own and operate the solar PV.

MR. BALDUCCI: Uh-huh. Yeah.

COMMISSIONER CLODFELTER: Okay. The only price signal that exists in this case is the contract price negotiated between the grid owner and operator, that's our regulated utility, and the solar PV generator.

MR. BALDUCCI: Uh-huh.

COMMISSIONER CLODFELTER: The -- assume that we add storage or that storage is added to a substantial chunk or maybe even all of that installed PV.

MR. BALDUCCI: Uh-huh.

COMMISSIONER CLODFELTER: The regulated grid operator has no control over what kind of storage is added, what technology, what the characteristics are technically or economically, what the costs are of that storage.

MR. BALDUCCI: Uh-huh.

COMMISSIONER CLODFELTER: Assume that that storage is really opaque to the grid operator --

MR. BALDUCCI: Yeah.

COMMISSIONER CLODFELTER: -- in terms of control. There’s no control. Grid operator has no control of that storage. It’s charged off grid. It’s charged on the generator side of the inverter. It never interacts with the grid directly except at the point of the inverter. Should I conclude from that -- and that’s really the model, that’s the case, that’s going to be that way. Assume that’s going to be the way the case goes forward. Should I give up trying to value any service or value stream from that storage other than arbitrage, pure arbitrage? Is there any other way I can in that case -- again, the only price signal I’ve got is the contract price of what’s paid for the energy.

MR. BALDUCCI: Uh-huh.

COMMISSIONER CLODFELTER: Is there any other way I can sort of effectively value any other stream of value from that storage?

MR. BALDUCCI: Yeah. So --

COMMISSIONER CLODFELTER: And if so, what tinkering or what modifications to the case do I need to do?

MR. BALDUCCI: Yeah. Well, I'll try my best to answer that question.

COMMISSIONER CLODFELTER: Okay. Well, I tried my best to phrase the question. I don't know if I got it to you --

MR. BALDUCCI: I totally understand it.

COMMISSIONER CLODFELTER: -- in an intelligible way.

MR. BALDUCCI: Yeah, yeah, yeah. No. I'm definitely following you. Now, why would the third party invest in the storage? Why are they doing that, in terms of is it a requirement of the utility? Are they going to use it for --

COMMISSIONER CLODFELTER: Well, let's just say I don't have an answer to that question other than the fact that we have people pounding on our door who are those generators who say they want to add storage.

MR. BALDUCCI: Well, would they otherwise -- would some of the energy produced by the PV effectively be curtailed or not compensated, or is there a higher compensation rate for --

MR. McDOWELL: Could be curtailed, but the avoided cost that they are paid is very granular now and has a higher value during those peak hours. So potentially it’s part of the arbitrage opportunity, but they could -- it would be a value proposition to them.

MR. BALDUCCI: Right, right. And there is a -- there is a regional energy market, but no ancillary services -- ancillary service market or -- yeah. Right.

COMMISSIONER CLODFELTER: Either.

MR. McDOWELL: Yeah. Either.

MR. BALDUCCI: Well, okay. Or there’s a just a time of use component to the --

MR. McDOWELL: Right.

MR. BALDUCCI: -- to the energy price.

MR. McDOWELL: Right.

MR. BALDUCCI: Okay. All right. Yeah.

COMMISSIONER CLODFELTER: The question is should I just give up trying to sort of value anything other than arbitrage?

MR. BALDUCCI: Yeah. I don’t -- you know, I don’t know if -- so just a few things. So, you know, sometimes it’s a requirement the solar, you know, the storage with the solar would be a requirement because it has a grid impact if you just have intermittent energy hitting the system. Similarly, in the Pacific Northwest they will have to pay $15 per MWh for that solar that they produce if it’s above like 1 MW or something like that because the Bonneville Power Administration is effectively balancing that resource.

I would say this, that there is additional value that could be generated. How it would be captured typically is through third-party agreements with the utilities as opposed to, you know -- because, you know, it could provide some form of frequency regulation or it could provide a capacity benefit, right, because firming up that wind enhances its capacity.

So there are -- there are a number of values that could be generated. How you capture those values from a regulatory perspective, I mean, enabling the utilities to work with this third party to monetize it, I guess, and build it into their rates I suppose would be the way you do it.

MR. McDOWELL: Well, and you hit on part of that formula --

MR. BALDUCCI: Yeah.
MR. McDOWELL: -- earlier when you were talking about the intermittency and what role storage can play --
MR. BALDUCCI: Yeah.
MR. McDOWELL: -- in mitigating that, and that’s real here in North Carolina as well in terms of --
MR. BALDUCCI: Right.
MR. McDOWELL: -- recognizing that.
MR. BALDUCCI: But no one is penalized for making the situation worse?
MR. McDOWELL: In the avoided cost for the standard contracts, yes, there is a -- you could call it penalty or an opportunity there that --
MR. BALDUCCI: I see.
MR. McDOWELL: -- storage could play in.
MR. BALDUCCI: Uh-huh. So could the Utility Commission work with the utilities to allow them to structure those avoided cost agreements differently to take advantage of those other value streams more extensively?
MR. McDOWELL: I think that’s part of the formula.
MR. BALDUCCI: Yeah.
COMMISSIONER CLODFELTER: I think that’s really

what the gist of the question was looking for, is where do we enter -- where do we enter this to try to sort of tinker? Do we enter it at the regulatory policy stage? Do we enter it at the contractual stage, which is really all we've got because we don't have markets?

MR. BALDUCCI: Right.

COMMISSIONER CLODFELTER: So all we've got is the contract negotiation instead of the market. Or is it something that requires technological retrofitting? Or does it require all of those?

MR. BALDUCCI: Yeah. I mean, I guess, you know, I'm not a regulatory expert. Those were the last two people that were here. But, I mean, it's generally -- my conclusion is that there is more value that could be generated, but from a regulatory perspective you have to enable the contracts to capture those values. So if you can do that, it seems like that would be the way to go.

MR. McDOWELL: So Patrick, obviously, there's some robust modeling tools available --

MR. BALDUCCI: Yeah.

MR. McDOWELL: -- to you that have evolved over time and are utilized to do these assessments that you've highlighted here, whether it's at Portland General or some of these others.

MR. BALDUCCI: That’s right.

MR. McDOWELL: Part of what’s advanced, you mentioned operational knowledge --

MR. BALDUCCI: Uh-huh. That's right.

MR. McDOWELL: -- as contributing to that. I read with interest on slide 27 the key lesson there, I think, is of interest, development of control strategies is required to obtain value in real time.

MR. BALDUCCI: That’s right.

MR. McDOWELL: We should not compete in developing real-time control systems; rather, we should propel the industry forward through development of advanced algorithms and this optimization performance enhancement tool. Is that your tool or is that just a general --

MR. BALDUCCI: That’s our tool, yes --

MR. McDOWELL: Okay.

MR. BALDUCCI: -- that we developed under Dr. Gyuk’s program.

MR. McDOWELL: So a lot of these algorithms you have in place, you want to advance those and continue to utilize those both in these specific projects that you’re contracted to. Is that knowledge transferable to all of the states in terms of what the models can produce or do you have to go through your own pilot programs to understand this to develop models of what --

MR. BALDUCCI: Yeah. So, you know, all the work we do is publicly available. We're a national laboratory. We have to make it publicly available. We can't withhold the -- after all, the taxpayers paid for it. Some of our tools are readily available in the public space, and you can sign an agreement, you know, just a legal agreement, it doesn't cost anything, but -- and utilize them, those it's challenging, of course.

You know, all these projects were -- almost all of these projects were funded through public entities, either the Department of Energy or through states, so there's interaction that way.

And then finally, you know, we do have, you know, regulatory funding as well to support, you know, states quite directly. So Jeremy Twitchell was here previously. He leads that space. So through that program if you wanted to access our capabilities and, you know, we come back, we share more information, we share the algorithms, we work with you, that can be done. And I think that there's probably funding available to do that sort of thing. I mean, that's what we're here for, really, is to improve conditions throughout the country, level the analytical playing field, you know, demystify how these systems operate and help, you know, more widespread development to more efficiency on the grid, so yeah, we -- I’m confident we could help.

CHAIR MITCHELL: One question for you. You mentioned in this -- I'm looking at your -- I guess it’s page -- slide number 7, but you mentioned for every 6 MW of renewables requiring at this point in time 1 MW of balancing. How developed is that ratio? Can you tell us just a bit about --

MR. BALDUCCI: It was -- it was a single study that we did --

CHAIR MITCHELL: Okay.

MR. BALDUCCI: -- about six years ago, actually. And what we did was we modeled a 20 percent nationwide renewable portfolio standard. So the idea was what if we had 20 percent renewable portfolio standard? Then we scanned the country. Where would you put, you know, wind and solar to take maximum advantage of the wind speeds and the irradiation and all of those things. And then if you place that in those grids -- and we had, you know, WEC wide, Eastern Interconnect wide, and ERCOT wide production cost models, you know, what would you have to do to maintain grid conditions at current levels, and then we established balancing resources required and then evaluated several different balancing resources, pumped-storage hydro, various battery systems, and combustion turbines. And the battery systems then didn't fair as well, but then forecast out to 2020 and, if anything, our forecasts were conservative. They performed quite well. So battery systems are very efficient doing that.

But that was effectively -- so it was a nationwide study that we developed based on a modeling technique and an assumption of a 20 percent renewable portfolio standard.

CHAIR MITCHELL: Okay.

MR. BALDUCCI: Yeah.

CHAIR MITCHELL: Thank you very much.

MR. BALDUCCI: Uh-huh. And once again, it was 6 to 1 if you were starting from nothing, but given existing resources it was more like 10 to 1 because we had some balancing resources that weren't fully called upon to provide this balancing, right, so on the margin we were saying 10 to 1, and that's nationally, but it was broken down by region. You'd have to look for the Southeast.

CHAIR MITCHELL: Thank you. Any additional questions from Commissioners?

(No response.)

CHAIR MITCHELL: Well, thank you, Mr. Balducci. We appreciate your time today.

MR. BALDUCCI: Yeah. Thank you very much.

CHAIR MITCHELL: Okay. And with that we will be adjourned for today. We will convene again on Tuesday, January 21st, in this same room at 1:00 for our next series of presentations. Thank you very much.

(The proceedings were adjourned.)

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STATE OF NORTH CAROLINA

COUNTY OF WAKE

C E R T I F I C A T E

I, Linda S. Garrett, Notary Public/Court Reporter, do hereby certify that the foregoing hearing before the North Carolina Utilities Commission in Docket No. E-100, Sub 164, was taken and transcribed under my supervision; and that the foregoing pages constitute a true and accurate transcript of said Hearing.

I do further certify that I am not of counsel for, or in the employment of either of the parties to this action, nor am I interested in the results of this action.

IN WITNESS WHEREOF, I have hereunto subscribed my name this 8th day of April, 2020.

Linda S. Garrett

Linda S. Garrett
Notary Public No. 19971700150