MANITOBA HYDRO'S

NEEDS FOR AND ALTERNATIVES TO (NFAT)

PREFERRED DEVELOPMENT PLAN

Technical Conference

HELD AT:

Manitoba Hydro

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Pages 1 to 260

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Regis Gosselin	)PUB Board Chairman
Marilyn Kapitany	)PUB Board Member
Larry Soldier	)PUB Board Member
Roger Cathcart	)PUB Consultant
Josee Lemoine	)
Sven Hombach	)
Larry Buhr	)
Hollis Singh	)PUB Executive
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Ed Wojczynski	)Manitoba Hydro staff
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Gloria Desorey	)
Meghan Menzies	)
Bill Harper (via chat)	)
David Lamont (via chat)	)
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Paul Chernick (via chat)	)
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Patrick Bowman	)
Melissa Davies	)
Marci Riel	) Manitoba Metis
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APPEARANCES (cont'd)

Erick Matthiesen (via chat)) Pattern Energy

Bruce Duggan)Providence

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--- Upon commencing at 9:12 a.m.

MS. PATTI RAMAGE: Good morning, everybody, and thank you for coming today. We greatly appreciate you coming on a beautiful July day. It was tough, I'm sure, for many to leave their cottages and homes this morning, but we're hoping for a really good couple of days.

The purpose of this session, from Manitoba Hydro's perspective, is to educate. It's -- there's some self-interest there, because we're hoping that by conducting these sessions, it will reduce the number of IRs.

So part of that is in order to achieve that on, one of the things we'd really like to see is that people ask questions. Don't wait until the speakers finish their topic to ask your question, because you might get lost along the way if you don't have that point answered.

So, please, if you do have a question, get your hand up so that the people who are joining us remotely hear your question. We will have someone come to you with one (1) of these portable mics so that they will catch it and the court reporter today here catches it.

The court reporter will be transcribing today's session. It's not under oath. Nevertheless, we will have that available to you so that you can revisit what we've talked about and -- and if you have any questions. I'm not sure exactly what arrangements have been made getting those transcripts out, but it may be a possibility that we can answer some of those things Wednesday. Hollis, you...

MR. HOLLIS SINGH: It will be on the PUB web site.

MS. PATTI RAMAGE: It'll be on the PUB's web site. Okay. That's perfect.

As I say, the goal is to educate. We're going to have a -- at least one (1), maybe more, people here today speaking who have never testified in a regulatory proceeding, never actually seen a regulatory proceeding. I have given them -- attempted to give them -- them comfort by saying the questions will not be cross-examination.

They're -- what we're looking for is questions of clarification on the materials that are here, as opposed to jumping ahead to what is next. So we'd appreciate it if everyone could stick to that and let me keep my word to these people that it'll be on what they know.

And I -- I think with that, maybe I'll turn it over to Ed. And he has a few words to say, introductries, comments.

MR. ED WOJCZYNSKI: Yeah, thanks, Patti. I'll try and keep my comments very short. It's going to be a long day today, a long day on Wednesday, and the less time you hear from me, the more time you'll have available to hear the stuff you're really here for.

Just a quick comment. On behalf of all the Hydro staff who are involved in this, including the -- the ones here, including the people who are not here in this room, we welcome you. And just a comment, that we live and breathe this material. And so each one of us who's going to be presenting will try and avoid getting into the super detailed, technical stuff that we talk to our technical peers about and try and make it at a -- at a level that people who don't have thirty (30) years or ten (10) years of background in the company can understand and be -- and help you understand what it is we're trying to say.

So if sometimes we lapse into terminology that doesn't quite work for most people, please stop us and get us to explain it. We'd be very glad to do that. I have the super-interesting job of giving you some of the housekeeping items here.

Washrooms are located between the -- the elevators. If you go to either door, exactly on the other side of this wall there's a hallway, and there's women's and men's washrooms right there.

The fire exit is on the north stairway, so out that -- north is that way, by the way, for those who don't have compasses on them. And there's a stairwell just down the hall. But if anything happens, of course, which I don't expect will, the Hydro staff will escort you.

Breaks are scheduled in the morning and the afternoon. When -- lunch will be provided. We have -- the agenda was sent out by email earlier. But, Dawn, we printed extra copies. Are they here yet? They're coming. We will have some extra copies of the agenda for the two (2) days that we'll hand out in case you don't have yours with you.

I think you just heard from Patti about the workshop being recorded and transcribed. If you -- if you'd like to ask a question, could you raise your hand? And then we'll -- we'll -- one (1) of the staff -- we have two (2) travelling mics -- will bring the mic to you.

And I think, as Patti explained,

otherwise, there are least two (2) people right now who are on the external audio connection. And this way, they'll be able to hear your question. And then obviously who gives the answer will also have to have the mic.

And the last comment, cell phones, the traditional please put them on mute. So obviously you're going to do what you have to do, but if you could have the -- the ringers off, please.

What we thought we would do is go around and have some quick introductions of everybody. It's a small enough crowd we can do that. We thought perhaps we'd start with the commissioners, and then go around the room.

MS. MARILYN KAPITANY: I'm Marilyn Kapitany. I'm a Board member at the Public Utilities Board. And I'll be on the NFAT panel.

MR. REGIS GOSSELIN: It's Regis Gosselin. I'm also a member of the -- the Board.

MR. LARRY SOLDIER: Larry Soldier. I'm also a member of the Board.

MR. HOLLIS SINGH: Hollis Singh, executive director and secretary to the Board.

MR. BOB PETERS: My name is Bob Peters. I'm legal counsel to the Public Utilities Board.

MS. ANITA SOUTHALL: Good morning. Anita Southall. I'm also counsel to the PUB.

MR. SVEN HOMBACH: Good morning. Sven Hombach, from Fillmore Riley, also counsel to the PUB.

MR. ROGER CATHCART: Roger Cathcart, accounting advisor to the PUB.

MS. JOSEE LEMOINE: Good morning. Josee Lemoine. I'm the project manager for the NFAT with the PUB.

MR. PATRICK BOWMAN: Good morning. I'm Patrick Bowman, with InterGroup Consultants. And I'm here with the MIPUG group.

MS. MELISSA DAVIES: Melissa Davies, from InterGroup Consultants, also here representing MIPUG.

MR. BRUCE DUGGAN: Bruce Duggan, from Providence's Buller Centre for Business. Oh, and I'm on 50by30.

DR. PETER MILLER: Peter Miller, Green Action Centre.

MR. BILL GANGE: Bill Gange, counsel to Green Action Centre.

MR. LARRY BUHR: Larry Buhr, Engineering Advisor to the PUB.

MR. BYRON WILLIAMS: Byron Williams,

Public Interest Law Centre, representing CAC (Manitoba).

MS. GLORIA DESORCY: Gloria Desorcy, from the Manitoba Branch of the Consumers' Association of Canada.

MS. MEGHAN MENZIES: Meghan Menzies, also with the Public Interest Law Centre, representing CAC.

MS. MARCI RIEL: Good morning, I'm Marci Riel. I'm from the Manitoba Metis Federation.

MS. ALANA LAJOIE-O'MALLEY: Alana Lajoie-O'Malley, I'm the director of the Campus Sustainability Office at the University of Winnipeg, and I'm with 50by30.

MR. BILL HENDERSON: Bill Henderson, Public Affairs, Manitoba Hydro.

MR. DAVE BOWEN: Dave Bowen, new gen construction, Manitoba Hydro.

MR. RALPH WITTEBOLLE: Ralph Wittebolle, division manager of new generation construction, Manitoba Hydro.

MR. TERRY MILES: I'm Terry Miles, with power planning in Manitoba Hydro.

MR. CHRIS ALLERTON: Chris Allerton, Manitoba Hydro IT services.

MS. MARLA BOYD: Good morning. I'm Marla Boyd, with Manitoba Hydro law department.

MS. JOANNE FLYNN: Good morning. Joanne Flynn, with power planning at Manitoba Hydro.

MR. DAVID CORMIE: And I'm David Cormie at Manitoba Hydro.

MS. PATTI RAMAGE: And I'm, again, Patti Ramage, Manitoba Hydro law department and I'll be here Mondays and Wednesdays if you're looking for something to do those days.

MR. ED WOSJCZYNSKI: And there are two (2) people right now on the external connection, David Lamont from CAC and Erick Matthiesen from Pattern Energy. Are there any others, Nicole, right now?

So before we actually start the presentations, are there any questions or comments at the outset that people would like to ask for -- about the process or anything before we get started?

(BRIEF PAUSE)

MR. ED WOJCZYNSKI: Going once... Going twice...

MS. PATTI RAMAGE: Does everybody -- we have two (2) dial-ins right now, or access. Does that meet everyone's expectations, in terms of are they thinking their -- their consultants should have contacted us?

MR. ED WOJCZYNSKI: Bill Harper you're expecting?

(BRIEF PAUSE)

MR. ED WOJCZYNSKI: Yeah. Okay. The question was what -- but what about Bill Harper coming on, and the answer is that he isn't on right now, but we expect him to come on and he has the information. Any -- does that work? Does that work for you? Okay. You're asking about Paul Chernick. He's not on yet either.

Okay. Okay. And when you people come on, Nicole will notify us. And as the moderator I will sort of announce that, I guess. We have -- someone else just joined us?

(BRIEF PAUSE)

MR. ED WOJCZYNSKI: Antoine, with MIPUG.

MR. ANTOINE HACAULT: Sorry. Hello,

everybody.

MR. ED WOJCZYNSKI: I'm looking at -- are you concerned about not having Bill right at the beginning here right now, or -- or the other individual, who I can't remember right now? No? Okay. So I guess we should get going, unless there's anything else. No? No comments from anybody? Okay.

So our first presenter is -- the agenda actually says that the first item is going to be presented by Dave Cormie, but it's going to be both Dave Cormie and Joanne Flynn doing the overview of the Manitoba Hydro system. But Dave is the one who is going to kick it off.

Okay. You have a lapel, right?

MR. DAVID CORMIE: Yes, I think everybody can hear me.

MR. ED WOJCZYNSKI: So the travelling mic, we'll leave it with Barb, and she'll bring it to anybody who wants to ask a question or make a comment. So that's why we ask you to raise your hand. Oh, yes, the presentations, we will provide those. They're -- they're just finishing be printed and being brought down, so you will have them shortly, hard copies in front of you, very soon.

PRESENTATION RE: OVERVIEW OF MANITOBA HYDRO'S SYSTEM:

MR. DAVID CORMIE: Okay. Normally I'm under oath. I understand from Patti's remarks I can say anything I want now, so...

Like Ed said, there's nothing that we can't explain better. If we have -- if -- if our presentations are -- are going off into jargon, stop us and we'll explain. It's -- it's a good time to -- to get the fundamentals understood, and questions are -- are completely part of this presentation.

Yeah, I'm David Cormie. I'm the division manager of Power Sales and Operations at Manitoba Hydro. My responsibilities include Manitoba Hydro's activities in the export market and power system operations, the management of the energy resources. Joanne and I are going to tag-team this morning. We've got quite a few slides to go through, and we thought it would be good just to -- to trade off every -- every once in a while.

So, with that -- oops. Can we go back? There we go. The first presentation this morning will be about the -- the power system, the system of generating stations, transmission lines, reservoirs, and -- and then we're going to talk about the -- the characteristics of a power system. And Joanne will --

will speak to that, including our planning objectives and our criteria. And there has been some -- some questions about the impacts of the preferred development plan on Lake Winnipeg. And so we're going to -- to talk a little bit about -- about that -- that subject.

Firstly, we need to make sure that we're all talking in the same -- in jargon. If you're in the gas, you have to know about joules. If you're in electricity, you need to know about megawatts and megawatt hours. As a homeowner, you may read your bill from Manitoba Hydro, and your bill is issued to you in kilowatt hours. If you -- and you pay about six (6) or seven (7) cents a kilowatt hour for your electricity.

But at the -- at the power system level, we don't talk in kilowatt hours. They're too small. But if you have a half a million customers and each customer is using 10,000 kilowatt hours a year, you have five hundred thousand (500,000) times ten thousand (10,000), pretty soon you're starting to talk about trillions of watt hours, or billions of kilowatt hours, and it's just too complicated to -- to talk about the units of measurement in -- in those terms.

So at the power system level, the units that we use are megawatts and megawatt hours. And so I want to talk firstly about what a megawatt is. A megawatt is a million watts. Imagine one hundred thousand (100,000) 1,000 watt light bulbs. That's a meg -- a megawatt. And in terms of what it is, it's the maximum rate of power output, just in the same way that what's the capacity of the engine in your car? It's measured in horsepower.

If you asked about your car, they'd say, Oh, it has a 200 horsepower engine. It can put out 200 horsepower if you put the pedal to the -- gas pedal to the floor. That's the maximum amount of power that that car engine can produce.

Well, in the same way, in the -- in the power system, if all the generators were running at full output, that would be -- that would be the capacity of the Manitoba Hydro system, and we would measure that in megawatts. And that number is around 6,300 megawatts. So 6,300 million watts, that's the capacity. That doesn't talk about energy; that's just the capability. It's the capability of the engine to produce -- produce power.

As I came up in the elevator this morning, the sign on the wall in the elevator said, "Capacity of the elevator: twenty-two (22)." You can get twenty-two (22) people in that elevator. That's the capacity of the elevator. Do you ever have twenty-two (22) people in an elevator? No. You can't squeeze them in there. But theoretically, if you put twenty-two (22) people in that elevator, it could carry twenty-two (22) people. That would be the capacity of the elevator.

So the other -- the other unit that we talk about it is -- is the energy. And energy is measured in -- it's the capacity times time. So if you had a hundred watt light bulb and you ran it for ten (10) hours, you would produce a hundred times ten (10), that would be a kilowatt hour, or a thousand watt hours. And again, if you take everybody's electric bill and you multiplied it by the number of customers, we would be talking about billions of kilowatt hours consumed in electricity.

At the wholesale level, at the planning level, we don't talk in terms of kilowatt hours, but that's how you get billed. We talk about it in terms of -- of gigawatt hours or megawatt hours. If you hade a hundred-megawatt unit running for twenty-four (24) hours, it would produce 2,400 megawatt hours of production in a day.

The -- the analogy in a car is how many litres of gas does your car use a year? Well, it's the

-- it's the gas that you use to drive the engine. Well, in my family we probably use about 2,500 litres of gas a year. And that's different than the capacity of the engine. The capacity of the engine is 200 horsepower. But when I run it for all the times that I need over the year, I'll use 2,500 litres of gas.

So the energy produced is the amount of energy that's generated by the -- by the power system in a year. And for Manitoba Hydro's system, when we have average water flows, it's around 32,000 gigawatt hours, or 32 million megawatt hours, or 32 billion kilowatt hours, or 32 trillion watt hours.

This -- and we don't want to talk in those terms, so we have these abbreviations. And -- and the units of measurement are when you're talking about an -- an hourly scale or megawatt hours. But when you start aggregate -- aggregating them over the month -- when you start aggregating over the month, you start talking in gigawatt hours.

So the power system might produce 2,000 or 3,000 gigawatt hours a month. Over the year it'll produce around 32,000 gigawatt hours over the whole year. And even this number is getting big. So there'll be a few slides where we actually show it as 32 terawatt hours.

So we're going to kind of -- you know, when you have a graph and you're trying to put those big numbers on the side of the graph, there's not enough room so, you like to just put the important numbers. And -- and when we talk in terms of -- of gigawatt hours, it's just simpler to talk in terms of terawatt hours.

So the -- the power system generates around 32,000 gigawatt hours or 32 terawatt hours. Manitoba consumers in a -- in -- last year will consume around 25,000 gigawatt hours, 25 billion kilowatt hours. And so you can see there's a difference of around 6,000, 7,000 gigawatt hours. That's the surplus energy in the system, and that's the energy that goes to the market.

In an average year, Manitoba Hydro can sell between 10,000 gigawatt hours, and in a high-water year it can be as high as 14,000 gigawatt hours. But those are the kind of -- those are the units that we're generally going to talk about. All -- Joanne's planning is all done in -- in gigawatt hours for the energy and megawatts for the capacity. And so when you look through the supply and demand tables, those are the units that -- that we're going to be -- that we're going to talk about.

A couple of other things. You'll notice at times we'll be talking in term -- in metric terms when it comes to the facilities. Some dams have been designed in terms of metres, and -- and cubic metres per second. The legacy system of Manitoba Hydro is still imperial units. So when we talk about Lake Winnipeg, we're talking in term of elevation in feet above sea level. But when you talk about elevation at the Keeyask Generating Station, you might see metres.

So there's still this mixture of units that -- and it's just what the licences are written in. And if the licence is written in metric, we still regulate the reservoir in metric, the power system. So you'll -- you might notice that as we go through the presentation as well.

Is there -- is there something I need to do to keep this thing from falling asleep?

(BRIEF PAUSE)

MR. DAVID CORMIE: So what is Manitoba Hydro? In the context of North America, we're a medium-size utility. What's unique about us is we're predominantly hydroelectric. There are very few utilities like Manitoba Hydro in North America: BC

Hydro, Quebec-Hydro, Manitoba Hydro. A high proportion -- a very high proportion of -- of electricity produced from -- from water.

Because we're a hydro utility on the prairies, we have huge volatility in the water supply. That means we go from extreme drought to extreme flood, and you've seen that this year. Big rainstorm in Alberta; all of a sudden the Saskatchewan River goes from being a trickle to being in a massive flood. And that -- and -- and so the variable is -- is huge. And for a utility in North America, we have the greatest variability in water supply.

(MOVED TO SLIDE 5)

MR. DAVID CORMIE: Now, if you're fortunate, you have a bunch of reservoirs that catch that water. And -- and it really doesn't matter how it arrives, as long as it's rising. And if your reservoir's big enough, you can hold that water and then meter it out over time in order to shape the supply water in to match the demand of electricity.

We're not that fortunate because the amount of storage we have relative to the volatility is -- is pretty -- pretty small. If -- if you gave me my druthers, I'd -- I'd have another -- twice as much storage in the system. And then we would be able to manage the flows properly. But we don't. Quebec-Hydro has much more storage relative to its water supply voli -- variability than we do.

So the -- the large volatility in -- in water supply means that our hydro generation varies. It can be as low as -- okay, I'm going to use the word 'gigawatt hour' -- 1,500 gigawatt hours in a low year of how much hydro we could have. But in a really high year it can be as high as 37, 38,000 gigawatt hours, so more than double the minimum, so lots of volatility. And -- and that -- that's a unique characteristic.

We're physically remote in the -- in -- in the electric system. North America is divided by a line, and there's the Western Interconnection and the Eastern Interconnection. And that dividing line is the border between Alberta and Saskatchewan. And if you were to draw that line due south all the way to Texas, everything west of that is the Western Interconnection and everything east is the inner -- Eastern Interconnection. And this chart shows that -- that dividing line. It's right here.

So you can see Manitoba Hydro is sitting up here in the northwest corner of the Eastern

Interconnection. I mean, not a lot of people up here. We're -- we're sparsely populated. Most of the load is in -- in north -- in the Eastern Interconnection is down here south of Chicago, south of the Great Lakes. And so relative to where all the generation is and where all the electric demand is, Manitoba Hydro is isolated up in the north -- northeast corner.

The connections across the -- oops. The connections across the east -- the -- the interconnection between the Western Interconnection and Eastern Interconnection are shown on this chart. There's these little arrows that you can see. But there's a couple of hundred thousand megawatts of generation on -- on the Western Interconnection and -- and more than that on the Eastern Interconnection.

But the megawatts of transfer capability across the regions is small, measured in a few thousand megawatts. So you've got these two (2) huge electric grids that are very lightly connected. The connection between Alberta and Saskatchewan is 150 megawatts. Alberta load is 10,000 megawatts, Saskatchewan and Manitoba are another six (6). So there's not a lot of room for trade to go across that border. So we're -- as I say, we're remote when it comes to the -- to the Eastern Interconnection.

We are surrounded by predominantly summer-peaking thermal utilities. To the west, Saskatchewan, most of their energy comes from burning coal and natural gas. To the south, over most of the electricity in -- in Minnesota is produced with coal and natural gas. Northwest Ontario, lots of hydro in Northwest Ontario; but as you go farther south into -- into Southern Ontario, more hydro, more nuclear, and they were just in the process of shutting down the last of their -- their coal utilities.

Summer peaking, most of our neighbours, including Saskatchewan, Saskatchewan's peak demand is almost the same as their winter peak demand, but most of our neighbours have a -- their maximum demand for electricity in the summertime as a result of air-conditioning load.

Manitoba Hydro has its maximum demand in the wintertime because of heating load. We have about a thousand megawatts of electrically heated homes. And -- and that's -- you know, that's -- that's pretty -- like I think Quebec-Hydro has a winter peak as well, with lots of electric heating. So that makes us -- that makes us a little bit unique in North America.

And we're -- we're -- we describe ourselves as transmission constrained. If you look at that map, you can see all these big red lines. These are the major high voltage lines across North America. And you can see that Manitoba has only one (1) major high voltage line connecting us to Central Minnesota. And -- and there's not enough transfer capability there to meet all of Manitoba Hydro's need to connect into the market. So we describe ourselves as transmission constrained.

If you compare that to utilities down south of the Great Lakes, lots of transmission lines. They don't have issues of transmission instabilities. They don't -- they're -- most of their transmission limits are because the -- the lines are thermally limited. That means if -- they get to the point where they start to melt, and they'll sag into the trees.

And so -- yes, Byron...?

MR. BYRON WILLIAMS: Dave, it's Byron Williams, just in -- in terms of the transmission constraints within MISO, we've heard that one of the -- the challenges is the rich wind-producing plains of North Dakota, etcetera, there's not a lot of ability to move that power into the more lucrative Eastern marketplace, so it has a dampening influence on -- on prices within -- within MISO.

And I just wonder, I guess two (2)

questions. One is if you could comment on that. And, secondly, at some point in time will -- will Hydro be providing information relative to any transmission constraints within MISO as compared to between Manitoba and MISO?

MR. DAVID CORMIE: We are -- we are going to speak about congestion later on, Byron. But I can -- I can speak to the fact that -- that, historically, transmission was -- was -- is -- was -- was well developed within the region.

So on this -- on this map, you can see there's areas of different colour. Those would be the transmission regions, and within those regions there's probably about seven (7) or eight (8) NERC regions. Within those regions electricity flow was -- was really well -- well managed and there was lots of capability.

But between regions -- so if -- if Manitoba wanted to move its power out of the old map region into Wisconsin or in -- into Illinois, you would be moving out of the -- the upper Midwest region into other regions, and it's those seams issues. There's not enough -- not enough transmission.

Cause the regions were designed to be standalone regions of -- of power supply and demand, and not a lot of effort was put into connecting the regions. So when you start talking about moving wind from, you know, the plains of North Dakota through Minnesota, into Wisconsin, down into Illinois, the transmission grid was never designed for that purpose. Inter-region transfers were -- who's -- you know, who's going to pay for that? And it was never -- it was never an issue. S

o now that is becoming an issue because to develop the renewables, there's millions of megawatts of wind generation potential in Minnesota and North Dakota and South Dakota. There's millions of -- or hundreds of thousand megawatts of load in the -- in the Northeast United States. How do you get that across the regions?

And -- and this transmission grid that we have was never designed for the bulk transfer of -- of power. So what the US wants to do is develop this -- like an interstate highway for electricity, to develop the infrastructure on electricity like the gas system is.

And you notice that because -- in the gas system that there's very diff -- little difference in price in natural gas across the United States. It might be a -- a dollar or -- or, you know, a few cents per gigajoule basis spread between the pricing points in the United States.

That's because the transmission system has been built for continental transfers of natural gas. It hasn't been that way for electricity. In 1998 we had power prices of three thousand dollars ($3,000) in -- in California, and we're sitting here in MAPP, and I'm trying to sell it for a hundred dollars, right. Why can't I get three thousand (3,000)? Well, there's no transmission.

So the transmission system was never developed for Manitoba Hydro to sell power into California. And that's the -- that's now the objective, is to develop that transmission grid to allow these interregional transfers.

And that will be -- that's the way that renewables will be -- will be brought on line, because like hydro, renewables need to be developed where they are. You can't -- you can't decide where you want your hydro plant to be. It has to be at the place where the water falls, and the same with wind. Wind is in North Dakota. The load is in New York. How do you get it there?

MR. BYRON WILLIAMS: Thank you.

MS. MARILYN KAPITANY: Dave...?

MR. DAVID CORMIE: Yes...? Yes...?

MS. MARILYN KAPITANY: Could you just confirm: Did you say that there are a thousand megawatts of electrically heated homes in Manitoba?

MR. DAVID CORMIE: About that, yes. There's -- so -- so every degree that the -- that -- that it gets colder, we have about twenty-five (25) more megawatts of electric demand. So imagine -- and the -- and the heating kicks in at about, I don't know, let's say 15 degrees Celsius.

When it's fifteen (15) outside, you'll probably -- your heat will start to come on. So imagine -- imagine going from 15 degrees Celsius to minus thirty (30); that's 45 degrees. Forty-five (45) times twenty-five (25), is like a thousand -- a thousand megawatts. So you -- there's about a thousand megawatts of load. And that's mainly because rural houses don't have access to natural gas. Farm -- farm homes.

(MOVED TO SLIDE 6)

MR. DAVID CORMIE: So the power system that Manitoba Hydro has is made up of a -- a set of generating stations and transmission systems that -- that connect the generating stations to the load. We have about 500 megawatts of -- of hydro generation just east of the city on the Winnipeg River, but the -- but the vast majority of -- of Manitoba Hydro's generating assets are in the North, and -- and -- and the -- and the bulk of those are on the Nelson River near Kettle, Long Spruce, and Limestone.

In total we have about 6,200 megawatts of -- of capacity, about 5,200 megawatts of -- of hydro, about 3,700 megawatts of that generation at the Lower Nelson, about -- over -- over 70 percent at -- at -- as the Nelson River drains into the sea on the Lower Nelson. We also have about 5 -- 500 megawatts of thermal generating stations at Brandon and Selkirk. We have some combustion turbines at Brandon.

We have a hundred-megawatt unit at Brandon that can -- that burns coals. And we have a hundred megawatt, or 130 megawatt unit at Selkirk that burns natural gas. But -- but the -- the coal and the -- or the -- the natural gas units in Manitoba Hydro are very expensive to operate relative to the cost of purchasing power. So they -- they run very infrequently for economic reasons. They mostly run for training, proficiency runs, and -- and are there for emergencies.

We also have power purchase arrangements with neighbouring utilities, where we have the right to buy 500 and -- 500 megawatts of capacity, and we -- we include that in -- in our -- our supply.

The -- the transmission system is there to bring the electricity from the generating stations to the load. Most of the load in Manitoba, probably 80 percent of the load, is within 50 meg -- 50 miles of the US border.

And so the transmission system is made up of -- of two (2) major systems. One (1) is the HVDC system, and that's -- that's the Bipole 1 and Bipole 2. And that's shown on this chart as this line here. And then there's an AC system. And the AC system also connects Northern Manitoba to Southern Manitoba, and power can be brought south on that as well.

We have under contract two (2) wind farms: one (1) at St. Joseph, Manitoba, and one (1) at St. Leon, Manitoba. And Manitoba Hydro entered into power purchase arrangements with these companies, and -- and they -- they've installed 250 megawatts of wind turbines. But from a -- go ahead. Question?

MS. MARILYN KAPITANY: So 250 megawatts, but then is says zero, in terms of the supply that's --

MR. DAVID CORMIE: Yes.

MS. MARILYN KAPITANY: -- part of our 6,265 megawatts?

MR. DAVID CORMIE: Right. So the question is: So why do we show on the table here a zero as the supply? Well, the capacity of the turbine is two hundred and fifty (250). So when the -- when the wind is blowing the hardest, and all the units are running, the station will put 250 megawatts out. But Manitoba Hydro only counts capacity that's available at the time of the system peak, on a guaranteed basis.

When is the system peak? Well, it's in January; it's minus twenty-five (25), minus thirty (30) out. When it's minus twenty-five (25) and minus thirty (30), the wind rarely bl -- doesn't brow -- blow for certain. There's -- our experience is it's only blowing about half the time, so we can't count on that capacity to serve the load. So we -- from a capacity perspective, although there's 250 megawatts installed, it's not something that you can depend on.

And the other complicating factor is that all these turbines shut down when it gets to be 30 degrees. They -- they are not able to run when it's colder than that. So if -- if the peak temp -- if the peak demand occurs when it's minus thirty-five (35), and it's -- and the -- and the turbines shut down when it's -- when it's thirty (30), they're not available to run, even if it was windy. So there's a low -- there's a -- there's a low correlation between power output at the time of the system peak from -- from a wind farm. So from a planning perspective, we do not count the -- the capacity.

Fortunately, Manitoba Hydro is -- not fortunately, but the -- the characteristic of our system is that we're building for energy, not for capacity, so this is not really an issue for us that -- if we had an extra 250 megawatts of capacity, would it do anything to our plans? Probably not.

MR. ED WOJCZYNSKI: Dave...?

MR. DAVID CORMIE: Yes, Ed.

MR. ED WOJCZYNSKI: Maybe a clarification on what Dave said. I think, Dave, you're referring to the front end, but later on in our sequence, when we become capacity short, then that does become an issue, the issue of capacity and energy.

MR. DAVID CORMIE: Okay. I'm -- I haven't looked at the latest --

MR. ED WOJCZYNSKI: Yeah. Yeah. I mean, you're dealing with the front end of the sequence, the operating, we're talking --

MR. DAVID CORMIE: Yeah. Okay.

MR. ED WOJCZYNSKI: -- about the thirty-five (35) year sequence. We eventually become capacity short, so --

MR. DAVID CORMIE: Okay.

MR. ED WOJCZYNSKI: -- then that does become an issue.

MR. DAVID CORMIE: Sure.

(MOVED TO SLIDE 7)

MR. DAVID CORMIE: The -- the Manitoba Hydro system is hydraulic. I'm sorry, question?

(BRIEF PAUSE)

MR. BRUCE DUGGAN: So I take your point with only two (2) wind farms. That's kind of a minor capacity. But if you had twenty (20) wind farms, would you still say that you had zero capacity from wind?

MR. DAVID CORMIE: You know, if all the wind farms were in the same location --

MR. BRUCE DUGGAN: Well --

MR. DAVID CORMIE: -- and it's -- it's not windy in the same location, you would have no capac -- but if you had a diversified -- if you had a diversified wind portfolio with the -- with -- with the wind turbines spread across a wide region so that when -- you know, when it -- when it wasn't windy in one (1) area -- so from the MISO footprint, in -- in the MISO world, they only accredit 10 percent of the capacity, even though the MISO wind is spread all over a -- a large region.

But for a -- for a local area like Mani -- Southern Manitoba, where our wind is concentrated, I -- I don't think there's enous -- enough diversity there that -- when it's thirty (30) below in Winnipeg, it's thirty (30) below in Altona and thirty (30) below in Winkler and thirty (30) below in -- in St. Leon.

So the weather -- weather is continental. And --

MR. BRUCE DUGGAN: Yeah, I -- I get that.

MR. DAVID CORMIE: -- you really have to go to a broad -- go to a broad footprint before you get the diversity associated with winds.

MR. BRUCE DUGGAN: So you're saying that this is a standard practice for -- for how wind is treated by all utilities?

MR. DAVID CORMIE: Pretty well. But there is -- there is credit given to the wind capacity in the MISO market. At Manitoba Hydro, we can't count it for our capacity needs, but it -- it is, you know, we can -- we can accredit 10 percent of that -- that capacity and sell that, because now we're selling to a summer capacity market. And generally it's windy in the summer. There's no temperature limits associated with cold -- cold wat -- cold weather.

The -- the purpose of this chart is to show the extent of Manitoba Hydro's watersheds. The water rises out west in -- in the Rocky Mountains and it flows east towards Lake Winnipeg. Lake Winnipeg is the low point in the watershed, so water from Northwest Ontario, from the northern -- northeast corner of South Dakota, flows north up the Red River to Lake Winnipeg. Lake Winnipeg catches the runoff from -- from this -- this vast drainage basin.

It -- it goes into Lake Winnipeg and then Lake Winnipeg is the regulating reservoir. Yes?

MS. NICOLE FITKOWSKI: I have a question from an external guest, Erick Matthiesen. He says:

MR. DAVID LAMONT (VIA CHAT): For the past two (2) winters the St. Joseph wind farms has never been taken offline for solely temperature-related reasons, as indicated by the presenter.

MR. DAVID CORMIE: That may be true, but the question is whether we can count on them being online at the time of peak and that's the criteria.

So this -- this chart shows the -- the watersheds. The -- the percentages is -- is -- are -- are designed to show the percent of hydraulic energy that comes from that watershed. So you'll see a 20 percent in the centre of the Saskatchewan River Watershed.

So 20 percent of Manitoba hydraulic energy, that wat -- that energy rises on the Saskatchewan River. The Winnipeg River is 39 percent. So although the Winnipeg River footprint is relatively small, most of the lar -- it has -- it carries the largest burden with recov -- when -- when it comes to supplying electricity, because the water in the Winnipeg River flows through all the generating stations on the Winnipeg River, then it goes into Lake Winnipeg, and then it flows through all the generating stations downstream. So there's more head developed for -- for Winnipeg River water.

The watershed is brou -- is very -- is very expansive. That means that there's diversity in water supply. So if it's -- if it's dry in one (1) region, it's likely that it's going to be raining in another, and they -- it tends to be offsetting. And -- and -- but there -- there are times when we have drought everywhere.

(MOVED TO SLIDE 8)

MR. DAVID CORMIE: This chart shows the history of the water supply going back to 1912. Manitoba Hydro is very fortunate that we have a hundred-year record. What we're showing here is the variability from year to year expressed as a percent of average. The -- the average line is shown at a hundred percent.

And so you can see that there are years of low flow and there are -- there are years of high flow. And -- and, fortunately, we've been in -- in the last ten (10) years we've had average or better than average river flows, and so we have ups and downs.

What's important from a power system perspective in designing the future, as well, we have to be able to supply electricity even in the lowest water year. So we look at the historic record and we find the year in which the water flows are low. And if you -- you can see that this period here, after the 1930s, ending in 1939/1940, is the lowest flow on record.

We call that the dependable flow. That's the flow that you can depend upon. You can depend on that flow being exceeded all the time. So from a planning perspective, that's a very im -- important period.

We had a drought in 2003. We didn't come as low as the -- as the dependable flow figure, but I think we came within about 3 percent of -- of the -- of the number. So it was very close.

Now, there have been -- there have been changes to the watershed over time. And from Manitoba Hydro's planning perspective, we have -- we've adjusted back in time so that the flow record that we use reflects the current use conditions.

So people in -- in Alberta and Saskatchewan are now irrigating. So we assume that that irrigation is -- was -- had -- we go back and adjust the record as if that irrigation had taken place all the way back to 1912. And that -- that's the flow record that we use for planning and operating the power system.

Oh, I need to go back.

(MOVED TO SLIDE 9, THEN WENT BACK TO 8)

MR. DAVID CORMIE: I want to go back because this dependable flow issue is -- is really important. Dependable flow is the flow that we use and assume that will produce the hydro power for our firm customers. I don't want to be able to say to you, You know what, we're relying on -- on non-dependable flows to supply your electricity, and, you know what, we're not having a good water year, so we're going to have to stop providing you with electricity.

So our firm customers, whether in Manitoba Hydro, our domestic customers, or our export customers, are all served out of dependable flows, out of -- out of dependable energy, energy that will be there all the time.

The corollary of that though is that whenever you have more than dependable flows, you're going to have surplus energy. And --

MR. ED WOJCZYNSKI: Dave, hang on. Someone wants to ask a question.

MS. ALANA LAJOIE-O'MALLEY: Just regarding water supply, are -- are you guys looking at all at any impacts -- future impacts from climate change in water supply? Oh, sorry, Alana Lajoie-O'Malley, 50by30, of Winnipeg.

MR. DAVID CORMIE: The question was

about climate change. Yes, we have a very extensive program in climate change and we -- we've got a lot of material to show on that. I don't know if it's part of this workshop, but we'd be glad to -- to show you our -- our activities in that area. But we are -- we are studying climate change and involved -- and -- and looking at the impacts on the water supply in the future.

So we have --

MR. ED WOJCZYNSKI: Hang on a second. Maybe just to help answer that, in the submission there will be a reporting on our climate change program, the research that's been done and the implications.

(MOVED TO SLIDE 9)

MR. DAVID CORMIE: So if you -- if you were to look at that flow record in ninety-four (94) of the ninety (90) -- ninety-four (94) out of the ninety-seven (97) or ninety-four (94) out of a hundred, there is surplus energy available. And what -- the question is: What do you do with that -- with that surplus electricity?

Well, this is where interconnections come in. It's one (1) of the uses of the interconnection. You can now generate that extra hydro energy and you can -- and you can sell it into the external markets.

This chart shows the interconnected capacities. There are two (2) sets of numbers here. The numbers on the -- on the chart, those are the -- those are the -- the maximum flows that that -- those transmission lines can carry. So the 2,175 megawatts, that's how much power that -- that transmission system can -- can export to the United States. But not all 2,175 megawatts can be used for commercial purposes. We have to back off from that to -- to create some trans -- transmission space so that Manitoba Hydro can deliver its reserve obligations, and -- and also to accommodate unscheduled power flows that would occur on the transmission line.

So let's say that there was a -- a generator suddenly went off a line in Manitoba, so there's a lack of power. Where does the electricity come? It surges up from the United States. And so the power system operators have to maintain some transmission capacity in reserve for these unscheduled flows.

So you can see on the chart it says, "1,950 megawatts." That's the number of megawatts that can be scheduled on. The difference between nineteen fifty (1,950) and twenty-one seventy-five (2,175), these are for these unscheduled flows, including Manitoba -- the ability of Manitoba Hydro to make delivery of -- of electricity.

So there's -- so that -- that's -- there's always this confusion over, Well, what number do we use? Well, use the -- from the -- from the scheduling perspective, what -- what is used in moving electricity to market are the -- are the numbers shown with scheduling limits.

Then there are times when transmission lines are taken out of service for maintenance, so the scheduling limit goes down. And if the -- if a storm were to damage the line, we -- we would be without that transfer capacity for a while.

So the -- the interconnections were built in order to maximize the value of the surplus and energy and capacity. And so every -- almost -- with every large plant that we build, when we built Kettle, when we built Long Spruce, when we built Limestone, incremental transmission capacity was added because the power system was now capable of generating more surplus electricity because of the -- of -- as you add a hydro unit, you -- you add firm power and you also add surplus power. And the surplus needs to go to market.

Yes, Peter...?

DR. PETER MILLER: Why the large discrepancy between the import and export capacity to the US? And is there any fix, in terms of reliability, you know, for -- for Manitoba's system that could increase the import capacity?

MR. DAVID CORMIE: Well, as -- as I said, we are on the periphery of the North American electric grid. And if we were in the heart of the Midwest of the US, where all those big red lines were shown, those numbers would be essentially the same. But because we're stability limited, that's the -- that's the capability of the power system to -- to import more.

Our proposed new 500 kV line will have exactly the same import -- additional import capability as the export capability. The both increase by 750 megawatts. But the existing system can't support more than 700 megawatts of imports. And it -- it's just that -- that -- the characteristics.

So there would have to be some significant investment in transmission facilities to -- to move that number from 700 megawatts up. It's -- it's not a limitation in Manitoba. It's a limitation in -- I -- I believe it's in North Dakota and Minnesota.

(MOVED TO SLIDE 10)

MR. DAVID CORMIE: The other asset that we have that we use to operate the power system is reservoir storage. So the -- the water supply mainly comes in -- in the spring and the early summer, like we're -- in the period we're at right now. And that doesn't match the demand for electricity. The transmission connections to the United States aren't big enough to move all that surplus power to market. So at times there is surplus water that needs to be stored in the reservoir for -- for future generation.

Move to a time of greater value or greater need, and if -- if we -- if there's room in the reservoir and the water is being spilled at the generating stations, is it possible to back off the reservoir release and hold some of that water and not spill it but to -- to sell it later in the fall, when -- when water flows are lower or demand for electricity is higher? That's the purpose of the reservoir.

The reservoirs that are -- that are under Manitoba Hydro control are shown in this chart, and it -- this shows a history of storages activity since 1977. The -- the pink or the -- the beige area shows the range of storage activities.

The black line indicates the average. And so you can see -- shift -- the black line -- you can see on the black line it starts out in spring at around -- on average about 5 terawatt hours, or 5,000 gigawatt hours, in storage. And on average it rises to about 11 and 11 1/2 terawatt hours by this time of year, in the middle of July.

So about 5,000 gigawatt hours goes into storage on average in Manitoba reservoirs, bec -- because there's more water supply than there is demand for electricity, so that extra water goes into the reservoir.

And then that 5,000 gigawatt hours is drawn out of those reservoirs, over the -- over the -- the remaining months of the -- of the year so that the reservoirs, on average, are drawn down over the wintertime. And -- and by the end of March, they're -- on average, it's back down to -- to five (5). So the five (5) was put in, in the spring, and it's slowly drawn out over time, when the water supply is less than the demand, and there's a -- there's a need for that electricity.

You can -- yes, Byron?

MR. BYRON WILLIAMS: Excuse me. Byron Williams. Just wondering how vulnerable Hydro is to changes in the regulatory approach to storage on Lake Winnipeg? For example, there is a CEC proceeding coming up relating to the regulation on Lake Winnipeg.

And -- and just curious how, if at all, that might affect Hydro?

MR. DAVID CORMIE: Lake Winnipeg is a -- a critical asset. Over half the live storage in Western Canada is in Lake Winnipeg. And so the -- the 8 terawatt hours of storage there is -- is extremely important. And I -- I've got some slides later, Byron, to talk about Lake Winnipeg. Yeah. Yeah.

So the key reservoirs in -- that Manitoba Hydro operates in Manitoba are Lake Winnipeg, Cedar Lake, and Southern Indian Lake. There are other reservoirs in -- in Western Canada, but these are controlled by other agencies. So on the Winnipeg River, there's Lake of the Woods and Lac Seul. Those are controlled by the Lake of the Woods Control Board.

But that storage is effective for our use, because the -- the way they manage that water affects the flows on the Winnipeg River. And in Saskatchewan there's Lake Diefenbaker, and there's the reservoirs in the Rocky Mountains. And on the Churchill River there's the -- the -- Reindeer Lake. So this chart just refers to the -- to the reservoirs that -- that Manitoba Hydro controls.

These re -- reservoir operations are subject to limits. And so we have Water Power Act licences for these reservoirs, and they tell us how low the reservoir can be drawn and how high it can -- it can be filled.

In the case of Lake Winnipeg, Lake Winnipeg is also regulated for flood control. And you'll see on this chart, a -- a zone called 'flood zone'. That's when Lake Winnipeg goes above the elevation seven hundred and fifteen (715), when the reservoir is now being used to -- to manage the flood on Lake Winnipeg.

That water is not available for hydro generation. And you can see we can put in -- about 6,000 gigawatt hours will go into storage, but the licence requires us to spill that water away. We can't -- we can't operate that part of the -- of the reservoir for -- for hydro power. And we'll -- I'll talk about that in a little while.

Is this were Joanne steps up? No. No. Okay.

(MOVED TO SLIDE 12)

MR. DAVID CORMIE: The characteristics of a hydro system. So we talked about the large water variability. We're energy constrained because of the size of our interconnections; we can't call on that huge capability of the generating systems south of us to -- for energy, because of our transmission system. It is quite limited. We can only import 700 megawatts. We like to import much more than that.

We have resource diversity, so we have lots of different generating supplies: we've got wind, we've got hydro, we've got coal, we've got natural gas. And there are transmission limitations, and those have to do with the import and export capability.

The other characteristic is long lead times. It takes a long time to build a hydro plant, and these involve significant investments.

Energy-constrained system, our power system is designed to meet the -- the power demand in the lowest low period. And that's what this -- the -- this critical flow period. What is the dependable flow?

(MOVED TO SLIDE 13)

MR. DAVID CORMIE: It's also designed to meet the peak load. So if, for some reason, we had to put twenty-two (22) people in that elevator, we could get them in there. But in the case of megawatts, our peak demand is in the wintertime, and so we have to have enough capacity so that when the winter peak hits, when it's minus forty (40) out and everybody's calling for heat in their homes, there's enough capacity in the system, or purchased capacity, that that power demand can be met.

The -- another characteristic of our system is that there's surplus energy available in almost all the flow conditions.

(MOVED TO SLIDE 14)

MR. DAVID CORMIE: Resource diversity. We've got a -- a mix of generation types in times of drought and high fuel prices. So although in a normal year we don't have most of our energies produced from hydro, in the critical year, over 20 percent of our energy supply will come from non-hydro. It'll -- and I think in the drought of 2003 we were -- probably over 30 percent of our supply was coming from -- from non-hydro.

As I said, we have a mix of resources. And -- and the important thing is that some of those resources can be brought to Manitoba over the interconnections.

(MOVED TO SLIDE 15)

MR. DAVID CORMIE: Hydro generation is remote. Like all renewables, the resource is where it is, and you need transmission lines to bring power from the generator to the load. Lack of transmission means congestion. So if you have a generator and you don't have a matching capability on transmission, then you have congestion.

So if Bipole 1 and Bipole 2 goes down, sure, we have 3,600 megawatts of generators in Northern Manitoba, but how do you get the -- how do you get the power to Southern Manitoba? The -- the DC system is down. So that's the reason we're building Bipole 3, so we have an alternate path.

So you have congestion unless new transmission is built to handle, in the case of surplus power, to the -- to the export market. And congestion exists today in our exports to Ontario. Congestion occurs when all the wind turbines in North Dakota are operating at full load and we're trying to export maximum power in the United States. There's not enough transmission capacity into Minneapolis for both of us to sell, so prices go down. Prices can go negative. The other day, it was minus three thousand dollars ($3,000) a megawatt hour. That -- just telling everybody there's too much power, stop generating.

There's very limited ability to move power across Canada and the United States. And we talked about that earlier on, about the -- the region was -- the regional transmission is -- is robust. Interregional transmission is very weak. And -- and the best demonstration of that is we can hardly export anything east into Ontario or west into Saskatchewan compared to what we can do going south.

(MOVED TO SLIDE 16)

MR. DAVID CORMIE: I don't know if I really need to explain more than this except that you'll notice that those other Canadian utilities, like BC Hydro and Quebec-Hydro, that have large surpluses, have done what Manitoba has done. They're strongly interconnected north/south. They're not interconnected east/west. And the reason that they're not interconnected east/west is because there's more value in connecting to the south. There's a bigger power demand there, a greater ability to absorb the surplus that is available.

It's very difficult for -- for Saskatchewan to back all their generators down and absorb anything but a small portion of the surplus that Manitoba Hydro may have. So if we're going to invest in transmission, we want to build south to where there's a big enough market to absorb the surpluses.

(MOVE TO SLIDE 17)

MR. DAVID CORMIE: Here we go. Did I -- I probably used up half your time.

MR. REGIS GOSSELIN: David, there's a couple -- a couple questions, please. I just wanted to -- you mentioned that there was congestion to Ontario. Did you mean that there was -- that line is limited to Ontario?

You could sell more power if that line was -- had more capacity? Is that --

MR. DAVID CORMIE: Right. The way the market works in Ontario is that Manitoba Hydro is able to participate in the market, to offer their energy in, but they'll -- they constrain Manitoba generation off if there's oversupply.

Normally what they would do is they would say, Well, who's -- you know, we would be -- we would be on an equal footing with Ontario generation in Northwest Ontario. They don't do that. They say, Manitoba, you keep your power and we'll -- we'll let Ontario generators go first.

So there's not enough transmission capacity connecting Northwest Ontario to Southern Ontario so that all the power that's available for Manitoba could reach -- ultimately reach the market. So there's congestion.

Hydro One is building a new line from Sudbury across northern Lake Superior to Thunder Bay, and -- and that congestion should go away in about 2018 so that Manitoba Hydro should be able to inject and physically deliver power because if there's surplus in Northwest Ontario, it will be -- it will be able to reach Southern Ontario.

MR. REGIS GOSSELIN: Now, the line that goes from Manitoba to Saskatchewan is located where?

MR. DAVID CORMIE: Well, there's actually five (5) lines. Yeah, there's two (2) at Flin Flon and three (3) south of that. But -- but most of the transfer capability between Manitoba and Saskatchewan is tied up with returning Island Falls power. So Saskatchewan Power has a generating station in Northern Saskatchewan. They wheel their power through Manitoba and they eject it back into Southern Saskatchewan, in Southern Manitoba, so...

And then the rest of it is essentially reserved in case a large generating unit in Saskatchewan trips, and they -- they need to be able to have transmission to -- to accommodate the surge of power that would come in from Manitoba. So there's very little capacity on those lines that's available for commercial transactions, so...

MR. REGIS GOSSELIN: There was an announcement a few weeks ago by Premier Wall and Premier Selinger about --

MR. DAVID CORMIE: Yes.

MR. REGIS GOSSELIN: -- a new agreement. Could you -- could you explain that one to us?

MR. DAVID CORMIE: Saskatchewan has some mining load in Northern Saskatchewan, and they would like to serve that with a purchase from Manitoba Hydro. And so we're working on -- on a transaction with them to do that.

MR. REGIS GOSSELIN: And the Ontario line runs from where to where? Like the one going from Manitoba to Ontario, where does it run?

MR. DAVID CORMIE: There's two (2) 230 kV lines, and if you're -- if you're in the Whiteshell you'll -- and you go to Seven Sisters, there's the Whiteshell terminal station, those two (2) lines go east from -- from Seven Sisters and they go -- they go to Canora.

MR. REGIS GOSSELIN: And the AC/DC line that you referred to with respect to transmission that goes from north to south, it's running along to the Bipole? Is that --

MR. DAVID CORMIE: No, no. It -- I -- I -- that -- that was just a simplified schematic. There's a whole network that goes from -- from Thompson down the west side of the province through Neepaw -- Neepaw, Brandon. There's an integrated electric network that -- the -- I think the best thing is to look probably in the back page of the annual report. There's quite a detailed schematic showing the major high voltage lines.

I asked that question, Why are you showing just one (1) line on the chart? Oh, we wanted to represent the AC network. But there is -- there is an ability to -- to move Northern power into Southern Manitoba by switching Kelsey units onto the AC system, or to -- or moving power through Western Manitoba.

MR. REGIS GOSSELIN: Now, you made a reference to critical flow period. And could you explain that, please?

MR. DAVID CORMIE: The critical flow period is the -- is the period when river flows are -- historically have been the lowest. So I think -- I think the critical flow period for Manitoba Hydro is probably about eighteen (18) months long.

It starts, I think, in the spring of 1939, and it goes all the way '39 and all the way through 19 -- 1940. So it's -- it's longer than a one (1) year period. And that's the flow period that -- that is used to determine the dependable hydro energy.

MR. REGIS GOSSELIN: Now, looking at the -- at this chart that reflected the -- the various water supplies available, I think it's slide 10, it's showing a white line at the bottom, where it -- I guess it represents the -- the minimum that was available at -- at certain years.

MR. DAVID CORMIE: Yeah, that -- that's dead -- dead storage. It's -- it's not -- it's -- it's not used. It's not available. It -- it's kind of saying, Where do we start measuring from?

Well, we can measure from sea level. Those are just the nominal minimums. In 2003 we -- we had Lake Winnipeg at seven eleven point two-five (711.25) so it was essentially bumping along the bottom. Even though, you there's water from seven eleven (711) down to seven-o-nine (709) it's just not -- not available for use, either for licence or you can't get the water out of storage.

So I think our historical records and scientific -- shows what's usable, and I think that chart is a good demonstration of what's available in the low-flow year, and what's -- or what's -- what can be used in a high-flow year.

MS. NICOLE FITKOWSKI: Erick Matthiesen has a question. It says:

MR. DAVID LAMONT (VIA CHAT): Can you provide any more details on the geographic distribution of demand, i.e., Greater Winnipeg area, Southern Manitoba, Northern Manitoba?

And then he says:

"Same question for generation north versus south."

MR. DAVID CORMIE: I believe there's a

presentation this afternoon on load, and maybe Lois can best speak to that at her presentation, if that's all right?

MS. JOANNE FLYNN: Okay. I'm Joanne Flynn, and I'm the division manager of power planning for Manitoba Hydro, and I will carry on with the section here on planning objectives and criteria. Maybe. Okay, here we go.

(MOVED TO SLIDE 18)

MS. JOANNE FLYNN: Okay. So the main objective in -- in planning is to secure resources for the future needs for Manitoba and, as required under the -- the Manitoba Hydro Act, as well as to meet the firm committed sales that we have in existence at the time we're doing our planning.

And this is to do so at the least net cost to Manitoba customers. And so what that means is, we don't only take into consideration the cost, but also the benefits of the various development plans. Now -- and -- and also consideration for environmental and social impacts.

Now, because the load growth is forecasted to continue, adding generation is not a discretionary investment for Manitoba Hydro. But -- and that is because doing nothing is not an option. We are obligated to meet the load.

(MOVED TO SLIDE 19)

MS. JOANNE FLYNN: Okay. So the generation planning criteria is what -- what we must comply with when we do our planning. And having planning criteria is consistent across the electrical utility industry. And it's consistent also with NERC requirements. NERC being the North American Electric Reliability Corporation.

And NERC requires utilities to carry capacity reserves. And the capacity reserve carried by Manitoba Hydro is 12 percent of forecast firm peak load. And what this does is, it recognizes that there is uncertainty in both load growth and equipment ava -- availability, and so allows for high loads and for equipment breakdown.

Now, Manitoba Hydro, as a predominantly energy -- or, sorry -- predominantly hydro system, also has an energy resource planning criterion. And this is what -- what we've been talking about -- what Dave Cormie has been talking about when we've talked about that critical period. So there must be sufficient energy supply available to meet firm energy demand in the event of a repeat of the lowest water conditions on record. And the sources of dependable energy that we do count on are sourced from hydro, thermal, wind purchases, and imports.

(MOVED TO SLIDE 20)

MS. JOANNE FLYNN: So in terms of -- I'm going to talk about the hydro first of all, but -- and there is -- there is three (3) classifications that we talk about: dependable energy, which is energy produced by the system under the lowest flow conditions on record, so this is drought conditions; average energy, which is the average of energy produced from all historic flow conditions, so -- so this is truly an average across each one (1) of the flow conditions; and maximum energy, which is energy produced as a result of the most favourable flow conditions on record, which basically means we're in flood-like conditions.

(MOVED TO SLIDE 21)

MS. JOANNE FLYNN: So here again we've

got, this time, identified the critical flow period. And I think we've heard -- we've heard about this from Dave. So what we're doing is, we're designing for the critical period for energy from hydro resources. And as was mentioned earlier, a surplus would occur, except when the flows are at or near these critical systems. So, basically, ninety-seven (97) out of a hundred years, we'd have some form of fur -- of surplus.

And then when we do our planning, any forecast deficiency of dependable supply over demand signals a need for new resources. And this again is, we are planning to serve Manitoba load and any firm load commitments only from those dependable resources. So the difference between that line at the -- sort of just above the 40 -- 40 percent level, and above all of that would be surplus energy.

(MOVED TO SLIDE 22)

MS. JOANNE FLYNN: Okay. So the -- the energy sources, we just talked about hydro. And so when we look at it from a planning perspective, we include the dependable inflows, which is sort of the -- the chart that you've been seeing as a representation of inflows, plus the use of -- plus the use of reservoir storage.

From the thermal perspective, so for the coal and natural gas, it is the station output as if it's operated continuously, but then derated for outages and maintenance.

In terms of wind energy, wind energy is -- is calculated at 85 percent of the average annual wind generation in terms of what we are counting on as dependable energy. And this is to put it on sort of that same level playing field as the hydro is. We look at hydro from the critical period perspective and we look wind. It's -- it's difficult to predict exactly how much wind you're going to get out of the system. And this 85 percent of average annual wind generation is a representation of a 95 percent level of confidence in -- in the amount of wind that will be generated over the long-term, because these are all over a thirty-five (35) year period.

And then purchased energy, which is according to the generation planning criteria, something that we can rely on to a degree, must be on firm transmission, available on -- under contract. And there are -- there's some that we can also count on from organized power markets.

(MOVED TO SLIDE 23)

MS. JOANNE FLYNN: So surplus energy by design is a graphic representation of the effect of -- of adding generation. So the number of years in gigawatt hours are the scale. You see the firm load represented. And then if we add an increment of new generation, what you see is surplus energy in -- in the blue there that is labelled as "minimum" and "predictable." This is the dependable energy. This is below that critical flow period line on -- on the chart. And it's added just in time to meet firm load. And it shows a couple of increments coming in.

What we also get when we add that increment is we get an amount of surplus energy which is unpredictable. From year to year, we don't know how much of it will be there. And as -- as we add more the increment gets -- the increment of surplus energy gets bigger.

So that is why we say we have surplus energy by design. It's actually driven largely by the water variability.

(MOVED TO SLIDE 24)

MS. JOANNE FLYNN: Okay. So this chart is showing us if we continue to -- to build hydro resources out in time, and this shows us going from basically 1970 to 2090, and this isn't saying that there's any commitment to do this kind of thing, but this is showing if we ran all of the hydro potential out in time and built it all, this is the effect it would have in terms of surplus energy and dependable energy.

So you can see historically Kettle, Long Spruce, Jenpeg, Limestone being added, and the surplus energy being 8 terawatt hours to the median level and an additional 6 terawatt hours above that. As we put in Wuskwatim, Keeyask, and Conawapa, you see that surplus energy growing from 6 -- from 8 terawatt hours to 12 and 6 terawatt hours to 10. And then if we continued to develop hydro over time, it would grow to 15 terawatt hours and 14 terawatt hours so that it -- there's almost as much dependable energ -- surplus energy as there is dependable energy. And the value we get out of building the hydro plants is also to be able to take that surplus energy to market.

(MOVED TO SLIDE 25)

MS. JOANNE FLYNN: So then this is where the interconnections become valuable if you're going to build the hydro. What did -- what did the interconnections then give us?

Firstly, it provides market access both for the export of surplus power and the import of a diversed (sic) source of power. As Dave mentioned, the -- the interconnections to the markets we're connected to have different basis of resources, predominantly thermal at this time.

They also allow us to do capacity sharing due to load diversity. We talk about the south being a summer peaking load and Manitoba being a winter peaking load, and therefore, we can share some resources in order to be more cost effective. But we can't do that without a transmission line, without interconnections.

As well, risk mitigation, in terms of load forecast. There's uncertainty in the -- the forecast for load. And having a transmission line allows you to have -- to manage that uncertainty, whether it's too high or too low, more surplus to sell or a source for import.

The same is true for the climate change. Where there's uncertainty in the future as to whether there'll be more water or less water, or an increased variability in the -- in the events that may occur in terms of drought and flood, an interconnection allows you manage those, as well.

In the short term, it allows us to deal with emergencies and enhances grid reliability. So it allows -- and Dave talked about the transmission and the capacity of the transmission and having room on it to -- to hold an amount in reserve to deal with things like emergencies.

And the last point on this is that because we are moving predominantly hydraulic energy into the market, there's -- would be a decrease in overall regional greenhouse gases. They would need to -- they would need to run their thermal generators less.

(MOVED TO SLIDE 26)

MS. JOANNE FLYNN: So in terms of market access, then we just take a quick look at price. And so a typical summer day and a typical winter day is depicted here, and you see there's a shape to the day in both seasons. So the spot market price is highly variable and dependent on quite a number of factors, so the range in price can go from minus two thousand (2,000) to plus two thousand dollars ($2,000) a megawatt hour.

So it is -- it is difficult to just pick a typical price. It's always changing. There's pri -- different prices in the on-peak versus the off-peak, and what we end up typically depicting are just averages which don't really represent the variability that you see in the -- in the market price.

Meanwhile, the marginal cost of hydraulic energy is in that five dollar ($5) range because it is invest -- the -- the large spend for it is up front, and the operating costs basically consist of -- of water rentals. Hydro is a flexible resource and -- and can be backed off and ramped up as required.

(MOVED TO SLIDE 27)

MS. JOANNE FLYNN: So this picture is a picture of the spot price in the MISO market at a particular five (5) minute point in time. There's tremendous variability across the region, and the price for Manitoba energy is at the border.

In this particular shot, the price is at minus two thousand two hundred and forty-six dollars and forty cents ($2,246.40); not the best time to be selling. But the price is location and time dependent, so you also see the price at the Minnesota hub is at seventy-three dollars and seven cents ($73.07). So with firm transmission we can move the delivery point and get the price at a different node. So the value of us having transmission positions in the MISO market also gives us a greater opportunity to take advantage of different prices in the market.

(MOVED TO SLIDE 28)

MS. JOANNE FLYNN: Okay. So investing in hydro, they are large -- large upfront investments with the majority of the cost in civil structures providing a fixed cost, once constructed, and low stable operating cost that provide a basis for stable rate increases. In addition, large plants can satisfy many years of Manitoba load growth.

(MOVED TO SLIDE 29)

MS. JOANNE FLYNN: As well, hydro plants take an extremely long time to get into place.

So exploration work can occur decades before a plant is -- is built, as can varying degrees of engineering work and environmental work along the way. And then going through negotiations, approvals, licensing, before we get to the construction period, which are also lengthy, it's not unusual to see twenty (20) years before a large hydro plant would be in place. So half a career for people or more. And what we are looking at are in-service dates of Keeyask at 2019 and Conawapa at 2026.

(MOVED TO SLIDE 30)

MS. JOANNE FLYNN: So the preferred development plan that we're talking about is this one with Keeyask in 2019/'20, Conawapa in '26/'27, a new 500 kV US interconnection in 2020, and a number of sale agreements.

(MOVED TO SLIDE 31)

MS. JOANNE FLYNN: Now, as we go through our resource sequence comparisons, we use a consistent methodology to evaluate any new addition that we look at. So it -- it doesn't matter whether it's hydro, thermal, wind, or purchases, the same methodology and the same models are used to evaluate the resource additions.

So this is standard practice across the industry, and it's been used over time by Manitoba Hydro at -- I think -- I'll call it as long ago as the 1990 PUB capital plans hearings and through to 2003 Wuskwatim ones, as well

So with that, I will turn it back to -- to Dave.

(MOVED TO SLIDE 32)

MR. DAVID CORMIE: Yeah. So there's this -- this issue of -- of impacts. If you change something, you add a new generating station, you add a new transmission line, you change the size of the Manitoba load, a power system changes. There's what we call 'system impacts'. The whole power system is operated as a -- as a unit, and -- and the various pieces will react depending on -- on what -- what changes you occur.

So when we add a generating station like Conawapa, there will be -- there will be a change to the power system, because you have the -- you may have the same water supply, you may have the same load but now you may dispatch the -- the generating system in a -- in a different manner.

And system impact could be -- it could affect the water levels on Grand Rapids. It could affect the water levels on Lake Winnipeg. It could affect the amount of energy that you're purchasing, because you're added now a low-cost resource, and why would you need to go to market. You may -- so the -- the -- from -- we -- we need to look at the impacts on the entire system from adding -- adding new -- new generation.

Now, when you add new generation in combination with the new interconnection and new export and import contracts, it becomes even more complicated. And so we have computer models that look at the interaction and dispatch the resources based on -- on the new resources being there, the new load requirements being there. And we can measure the -- the differences in -- in water levels in -- in how much energy that you purchase, how much -- how often the gas turbines run now.

And, so those are the things that -- that -- where the power system is affected by adding one (1) resource, it'll affect the way the other resources are -- are used.

Now, those impacts can be physical -- oh, the water level is a little bit different than I remember it being. The financial impacts can be huge. Manitoba Hydro has now borrowed -- I don't know what it's going to be, $18 billion. There's going to be an impact from that on the -- on the finances of Manitoba Hydro.

There is going to be environmental changes: less greenhouse gas emissions. We're going to -- if we change the -- the water regime maybe there's an environmental impact. And there's going to be a rate impact, so you go through the financial process, you go through the regulatory process, and -- and you know that if -- with different scenarios you have different -- different rate scenarios.

But remember, we are doing this in a dynamic world. And so the impacts of -- of adding the new generation are -- are only one (1) of the many variables that are occurring. And -- and what -- in our modelling we can -- we can fix a lot of the variables and say, Well, let's just change the -- the hydro system and see what -- the impacts on those. And, so we can go through various scenario analysis to -- to show what the impacts are on the power system but it's a -- it's complicated. It takes a long time to run the hydraulic models and then go through the -- the finical process.

And these -- these are not really trivial calculations that you can do overnight. They -- they take a long time to -- if that's the new sequence, the new scenario, what -- what does it involve, and what are the impacts in all of these four (4) areas?

(MOVED TO SLIDE 33)

MR. DAVID CORMIE: The -- the question that we were asked is: What's the effect of the new generation on Lake Winnipeg? Firstly, Lake Winnipeg is a -- a huge lake; it's the twelfth-largest lake in the world. And -- and it's not only impressive that way, but it's also impressive in that it's half the live storage in the Nelson-Churchill watershed. There's about eighteen (18) ma -- major reservoirs. Seventeen (17) of them comprise 50 percent of the storage. Lake Winnipeg is the other 50 percent, and that's just because of its -- its huge extent.

We have a licence to regulate Lake Winnipeg from the province. And there's a -- a -- historically, there was a water level range from as low as 709 feet, up to 718, so there was a 9 foot range. Now that range has been reduced to 4 feet for the purposes of power, between elevation seven-eleven (711) and seven-fifteen (715). So as long as the water level's be -- in that 4 foot range, Manitoba Hydro can regulate the outflows for power purposes.

When the level goes above seven-fifteen (715), the licence tells us now the dam at Jenpeg has to be opened wide, and you have to let as much water as physically possible down the river. And -- and that's when the -- the flood management rules in the licence kick in.

So right now, we know with the flood that's coming from Alberta, Lake Winnipeg's at seven-fifteen (715); we're at maximum discharge. And regardless of the benefits or disbenefits to power, that water has to be moved down the river. And -- and there's a lot of water being spilled in the power system. But that's to provide flood relief on -- to the -- the people around Lake Winnipeg. And those rules are all set out in our Water Power Act licence.

Now, we don't actually regulate the water level on Lake Winnipeg, so the water level at every point in the lake is whatever the wind is doing at that moment. What we regulate is the outflow, so we control how much water leaves the lake. And if more water is leaving the lake than is flowing in the lake -- the -- the lake, the level of the lake will drop because you're taking extra water out of storage.

If the -- if the opposite is true, like's happening now, more water is flowing into the lake than even can be passed at maximum discharge, the level of the lake will rise. So over the next few weeks Lake Winnipeg might get up to seven fifteen point two (715.2), or point three (.3). As that flood wave from Alberta is coming in, we're absorbing it, and then passing it downstream.

But the Lake Winnipeg regulation project is successful in managing the floods because we built channels at the north end of Lake Winnipeg, shown in that -- in that red box, so that we can get 50 percent more water out of the lake now than was possible in a natural condition. And so that 50 percent more water provides the flood benefits to Lake Winnipeg.

In the wintertime, that 50 percent outflow capability is beneficial to Manitoba Hydro. Because, in the winter, when our power demand is high, when all those a thousand megawatts of electric heating load are high, we can get more water out in the winter. So the -- the outflow capacity in the winter gives us the be -- Hydro the benefit. The outflow capacity in the summer provides the flood control benefit on Lake -- to Lake Winnipeg shoreline owners.

So Lake Winnipeg is a hugely important asset for Manitoba Hydro. It's -- 70 percent of our hydro generation is downstream. And when Lake Winnipeg is in that hydro range, we can adjust the flows to meet the -- the power demand pretty precisely. Once we build Keeyask and Conawapa, it's importance becomes even greater. It now represents -- regulates the flow to almost 80 percent of the -- of the hydro capacity in the system.

(MOVED TO SLIDE 34)

MR. DAVID CORMIE: So a little bit of background on Lake Winnipeg. What won't change with Keeyask and Conawapa, the licence isn't going to change. We're operating under an interim licence. The Clean Environment Commission has been asked to hold public hearings into Manitoba Hydro's request to finalize that licence.

We've been operating the lake under standard terms and conditions since 1976. Those conditions haven't changed. We're not proposing to change those conditions when we apply for a final licence. All we're doing is taking it, changing the name of the licence from "interim" to "final". The province has asked the Clean Environment Commission to go out and hold public hearings, get public feedback on Lake Winnipeg regulation, because it is a very controversial subject.

So the -- but we don't expect the terms of the Water Power Act licence to change. It'll -- it'll convert from a -- an interim to a final licence, but it'll do it under -- under exactly the same terms and conditions that we have now.

What also won't -- won't change with Keeyask and Conawapa is our -- our approach to regulation. As we see floods coming, we don't wait for the water level to get to seven-fifteen (715) before we go to maximum discharge. It rained massive amounts in Alberta; almost instantly we started increasing the outflows from Lake Winnipeg so that we can provide the maximum amount of flood protection to the people on Lake Winnipeg. So our approach is to continue to anticipate our -- and -- and meet our flood management obligations.

And we have obligations to all the stakeholders around Lake Winnipeg. And our approach is to enter into dialogue, explain to them what -- what Manitoba Hydro is doing with regard to regulation, what things that we control and what things are -- are natural. For example, with the issue of erosion around Lake Winnipeg. That's not something that Manitoba Hydro's in -- is responsible for, but there's a perception that erosion is -- is affected by Lake Winnipeg regulation. And -- and so we go out there in a -- with a very comprehensive outreach program, meeting with the -- with the communities to explain. And we're going to continue to do that in perpetuity, because we have the responsibility.

What will change is the outflows and levels. But the main driver in outflows and levels is the water supply. Why are we at maximum discharge out of Lake Winnipeg now? Because there's a big flood coming, not because Manitoba Hydro chose to do that.

So the hydrology will drive what the outflows and -- and levels are to the most regard. If the -- if in -- inflows to the lake are high the lake will fill up because there'll be surplus. If outflows are -- inflows are low, we'll be -- we'll be cutting back flows.

Now, to the extent that we have some flexibility within that range of seven eleven (711) to seven fifteen (715), there will be slight variations in -- in those. But those changes in water flows will be minor as long as Manitoba Hydro builds an interconnection, so that the surplus energy can go to market rather than go into storage.

So imagine building a generation station like Conawapa, all of the sudden, having 40 percent more surplus from Conawapa but having no place to sell it to. Well, then what would you do? You would -- you would put it in reservoir storage and the lake would fill up. But -- so you -- if you had a sequence when you built a big power plant that doesn't -- and you haven't addressed the issue of what are you going to do with the surplus, there will be large changes in -- in -- could be large changes in the water regime.

So it's important, from a water regime perspective, and especially for Lake Winnipeg, to have -- to bring not only the generating station to the table, but the -- but the ability to manage the surplus.

(MOVED TO SLIDE 35)

The -- the history of the water levels is shown on this chart. We call this a -- the tunnel chart. And what this does is it shows for the -- starting about 1977 to date, the green area indicates the range of water levels that have been experienced with regulation. The red line in the middle is the average water level.

And you can see that the range is between seven seventeen (717) and about seven eleven (711) and seven eleven point four (711.4), seven eleven point three (711.3). So the range is, you know, about 5 -- 5, 6 feet.

The grey area shows the range had there not been regulation. The water levels would have been as high as seven nineteen (719), and the low levels would have been in -- in -- would have been lower. So what regulation has done is kept the water levels in a -- in a tighter band.

And you can see that without regulation the average water level, shown by the blue line, would be significantly higher than the level that actually was recorded by about a foot. So Lake Winnipeg regulation has lowered the average level.

And if you look at the history of water levels from '77 to date and you compare those to the history of water levels from 1912 to 1977, the average that has -- has -- that we've recorded and the average that was recorded prior to the project are almost the same. That red -- that red line is not significantly different. So the reason that there hasn't been a significant change in the average water level in Lake Winnipeg is because every time we built a large hydro plant we built interconnected, and there was no need to use more storage than was naturally being used in a state of nature.

And so on a daily basis, there may be slight changes in outflows, but we don't expect there will be a big impact on Lake Winnipeg as a result of building new downstream generation stations, as long as we have the transmission capability to manage the surplus.

(BRIEF PAUSE)

MR. DAVID CORMIE: I think we used up a coffee break.

MR. ED WOJCZYNSKI: So as Dave and Joanne have used up the coffee, and I think we're going to go overtime and there's no sleep for anybody tonight.

Seriously, for any last questions on these two (2) presentations before we take a break?

Maybe a quick question for you. We are running late. Maybe some feedback. Is there any commentary whether this is the right level of detail, too much detail? We've still got most of two (2) days to go, so we can tailor our approach to this based on any feedback. Or should we more or less keep on going like we are, maybe shorten the lunch break a bit, something like that? Any -- any comments from anybody?

Okay. So I'm not hearing any objections. I'm hearing that the level of detail is about right, and -- but we may -- we're going to have to shorten lunch, probably. So we'll plan on shortening lunch. And why don't we take a ten (10) minute break right now and come back at 11:00.

MR. DAVID CORMIE: Hey, Ed, we started fifteen (15) minutes --

MR. ED WOJCZYNSKI: Yes?

MR. DAVID CORMIE: -- late, so we're right on time.

MR. ED WOJCZYNSKI: Okay. Ah, that's good. Okay.

MR. DAVID CORMIE: It's not the presenters.

MR. ED WOJCZYNSKI: Okay. That's good to know. Thanks for that one (1), Dave.

Okay. Nonetheless, we're still going to have to take ten (10) minutes for -- for the coffee. and we'll see how we are at lunch time; maybe we can have forty-five (45) minutes.

--- Upon recessing at 10:50 a.m.
--- Upon resuming at 11:00 a.m.

MR. ED WOJCZYNSKI: Before the break I had indicated that perhaps we should perhaps cut back on our lunch. But upon further reflection and hearing that some of the attendees here are going -- are having some meetings at lunchtime, what I'm going to purpose to you is instead of cutting back on the lunch break, that we stick to an hour. And if we need extra time we go a little bit later than four o'clock. An advantage of that, it occurs to me, is that this is fairly dense material. It's getting piled on you overhead after overhead, and having a bit of a break over a long -- a full break over lunch might be better so that you can actually understand what -- and have a brain left for this afternoon.

So -- so why don't you think about that and we'll -- we'll see where we are at the end of the morning and revisit that. And maybe you just give that a little bit of thought, what your preference is, and I'll probably propose that at the end. And as we go on, it's back to the Joanne and Dave show. And Joanne...?

PRESENTATION OVERVIEW OF MISO MARKET:

MS. JOANNE FLYNN: All right. Do we have a presentation?

(BRIEF PAUSE)

MS. JOANNE FLYNN: So what I can start with is -- because this -- this presentation is -- is the overview of the MISO market. That -- MISO is the Midwest Independent Transmission System Operator, who's going through a name change at this time and has renamed themselves to be the Midcontinent Independent System Operator as of June of 2013, but they are the same organization.

(MOVED TO SLIDE 2)

MS. JOANNE FLYNN: And what they are as a transmission system operator is, firstly, a regional transmission operator, which is an -- an entity that has responsibility for grid operations, short-term reliability, and transmission service; in this case for the midwest market, or what they're calling the midcontinent now.

And in addition to that they act as a market operator for wholesale -- for wholesale power. So they have two (2) responsibilities, one (1) for reliability and one (1) as a market operator.

(MOVED TO SLIDE 3)

MS. JOANNE FLYNN: So the scope of operations is -- is shown in slide 3. So -- and these are the -- the two (2) separate perspectives. The membership in MISO looks different from a market perspective than it does from a reliability coordination perspective. And Manitoba has a reliability coordination agreement with MISO and is shown as a member on the bottom map.

So you see -- see Manitoba shown on that map. Whereas, for -- from the market perspective, Manitoba's an external market participant and not considered to be within the footprint of MISO.

So the generation capacity therefore has two (2) different numbers. One (1) for the market operation separate from the reliability coordination one. So a hundred and thirty-one thousand five eighty-one (131,581) for the market, a hundred and forty-three seven sixty-five (143,765) for reliability.

As well, historic peak loads market just under a hundred thousand, reliability just over a hundred thousand. And so that includes eleven (11) states and -- and Manitoba. And the region serves 39 million people.

(MOVED TO SLIDE 4)

Okay. So just another note on the -- I guess the -- the size of MISO is that there's work in progress that will add another fifteen thousand five hundred (15,500) miles of transmission and 30,000 megawatts of generation to MISO called -- the MISO South Integration, which you can see on the -- on the slide.

But it's not expected to have a huge impact on what -- what's now sort of the northern main part of MISO, because the connection between the historical size of MISO and the MISO south region is only a thousand megawatts. But that is -- they expect to have that integrated into their footprint by

December of this year.

(MOVED TO SLIDE 5)

MS. JOANNE FLYNN: Okay. So the installed generation cap -- capacity in MISO. So now this is from the market perspective. And what you see is that in the MISO footprint coal is about 48 percent of the capacity; natural gas and oil, 32 percent; nuclear, six (6); renewables, consisting of wind, hydro, and 2 percent of other, making up the rest of it. And the capacity in megawatts in the little table there beside it.

And I'll go through a couple of these to show kind of the makeup and how -- what -- what the source of energy is within the MISO market.

(MOVED TO SLIDE 6)

MS. JOANNE FLYNN: So this chart does have some -- this table does have -- have some cryptic names on it so I'll just take a moment to explain that.

So there's three (3) markets from the eastern part of the US on here: the Northeast, which is the first column, PJM, which is

Pennsylvania/Maryland/New Jersey and New York, there's also Ontario: the California/ISO, that's the CAISO; and MISO.

So when you look across the US, you see that 42 percent -- now we're talking energy, not capacity -- 42 percent of the energy supplied across the US is from coal -- this is 2011 information based on the actual energy generated, not installed capacity -- 26 percent is natural gas and oil; hydro, 8 percent; nuclear, 9 percent.

When you contrast that to MISO, MISO is a high coal-reliant region. So 75 percent of the energy in 2011 was from coal, 5 percent from natural gas and oil, 1 percent from hydro, 13 percent from nuclear, 5 percent from wind. And those -- those percentages change by year, by month, as the generation mix changes and depending on the requirements for a particular year, and certainly a particular month.

(MOVED TO SLIDE 7)

MS. JOANNE FLYNN: So we look at January of 2013 to bring some more current information into it. And you see the MISO energy supplied by fuel type in January of 2013, 71.2 percent for -- for coal;

gas at just under five (5); wind at almost ten (10); nuclear, thirteen point six (13.6). Those -- those are the big ones.

If we look at April, you see the coal percentage has dropped from seventy-one (71) to sixty-eight (68), and the nuclear one has dropped a bit, as well. Gas is up a little bit.

(MOVED TO SLIDE 8)

MS. JOANNE FLYNN: Now, the springtime is usually a time of year where there is outages taken by the thermal plants for maintenance because loads are lower. So there's -- it does have an effect on the -- on the supply provided. So every month will have a different mix of resources that gets used, but pretty constantly across MISO will be a predominance of -- of coal.

(MOVED TO SLIDE 9)

MS. JOANNE FLYNN: Now, in terms of the MISO -- yes, a question.

MR. BILL GANGE: Is the 1 percent of MISO that's hydro, is that -- is that entirely from

Manitoba?

MS. JOANNE FLYNN: No, this, I believe, is the resources within -- within the MISO footprint itself. They do have a little bit of -- of hydro in there.

MR. DAVID CORMIE: Manitoba -- Manitoba Hydro generation and load is not in the market, right. Remember? So -- so from a reliability coordinating perspective, we are, but -- but Manitoba Hydro does its own dispatch of its own generation and it meets its own load. We don't rely on MISO to do that.

So these MISO statistics are about the -- all the generation and load in the -- in the US in the MISO footprint.

MS. JOANNE FLYNN: Okay. So when looking at things from the market perspective, first of all, we need to be aware that there's a high percentage, approximately 95 percent of the generation in MISO, owned and operated by vertically integrated utilities. And it is the utility that has the obligation to serve load, not the market.

So when there is a need for new resources, the utility looks at when they're required and how to get them, either through construction or through bilateral agreements with other utilities.

So in the end, from a market perspective, there isn't a large reliance on the market to provide -- to meet the load. That is still the responsibility of the utility. But MISO does have the responsibility for dispatching all of the resources. So all of the resources and the load are recognized in the market, but the -- the requirements are already met. It's like the -- the generators and loads are entered into the market, but really a utility is serving its own load.

So that means that the market is effectively a balancing market. There will be some shortfalls, some minor reliance on the market to supply for periods of time, but not for the majority of the energy and -- and capacity that is required to serve load.

(MOVED TO SLIDE 10)

MS. JOANNE FLYNN: So then how is the -- how is the mar -- how is the energy or electricity priced in the market? And there's two (2) main components for the electricity price: the variable production cost and the capacity charge.

So the variable production cost is the

cost of producing the energy. And in a thermal system, this is largely fuel, natural gas costs or coal costs, and in the future would be expected to include the cost of carbon credits.

The cost of energy is captured in the day ahead of real price real-time markets so that we would expect that to be reflective of variable production costs. And the US also has -- in -- in their system the costs flow through to the customers through fuel cost rate adjustments. So they're -- so they are allowed to recover those costs from -- from the ratepayer.

From a capacity perspective, which is the fixed costs or capital costs, this represents the cost of having a plant available for generation just sitting there, ready to go.

So the cost of -- of capacity then is not captured through the energy price but through either bilateral sale arrangements or the planning reserve auction revenues that actually are quite new to the MISO market. So the cost of capacity is not incorporated in that day-ahead and real-time price that you see from the market.

And the -- the production -- the variable production cost is what a generator would be expected to offer their generation into the MISO day-ahead market at.

(MOVED TO SLIDE 11)

MS. JOANNE FLYNN: So how do they arrive at the price? So generators offer their output of their units into the market based on this variable cost of production, fuel cost, variable O&M, and emissions permits, if -- if that's part of their profile.

The market operator uses security-constrained economic dispatch to stack the orders from lowest to highest in cost. And -- but the security-constrained part of that brings in their reliability responsibilities. They're not going to select generators that are on the other side of a transmission constraint.

So if there are limitations on line capacities, they have to take into consideration the physical limitations of the system. And this is where congestion comes from. So you may have a lower-cost generator on the other side of the transmission constraint, but you're going to have to dispatch a higher-cost generator, because you can't get that energy to the -- to the load.

So after doing this, security-constrained economic dispatch, so once they've taken into consideration the constraints of the system, they will stack the offers from lowest to highest. And each generator who runs gets paid the market clearing price for that hour. And that is representative of the variable or marginal cost of the most expensive generating unit that is needed to meet the load requirements in that hour.

(MOVED TO SLIDE 12)

MS. JOANNE FLYNN: Okay. So the next slide is a -- a schematic of an illustrative supply curve. And we've got two (2) examples on here, so it really would be easier to see the screen on this one, but...

(BRIEF PAUSE)

MS. JOANNE FLYNN: Well, I guess just to start with, you can see the different offers. This -- this example has a number of offers stacked from lowest to highest.

And basically, the first example is for 700 megawatts of load. And you see the -- the load line in the dashed black line, the one that's at the lower price there. And what that means is the clearing price, to meet that load, would take you to that generator and it would be in that -- you've got dollars per megawatt hours there on the Y-axis, so in that range of fifty dollars ($50) a megawatt hour.

A higher load -- if the same -- if the generators offered in at the same costs, a higher load would require us to go up the -- the offer stack one (1) more generator. And then the market clearing price for a 900 megawatt load would be at seventy dollars ($70). So all the generators that bid in and were cleared to run -- so that's everybody lower in the stack -- is expected to run now, they will get paid the market clearing price of seventy dollars ($70).

And that's the energy component in the price. And as Dave mentioned earlier, there would be congestion costs on top of that, as well as losses. So the -- the prices actually consist of three (3) components, the energy, congestion, and losses. And that's what creates the difference across the footprint in the pricing.

(MOVED TO SLIDE 13)

MS. JOANNE FLYNN: So the next slide is one that I showed you not that long ago. And again, just a reminder, summer -- a summer day versus a winter day. There's going to be all this variability in the -- in the price, even across the day from -- from going from the off-peak hours through to the on peak and -- and as you go from zero to twenty-four (24) hours, back down into -- into the off peak.

So this does is it creates those points in time where Manitoba Hydro could purchase in the lower-cost hours and sell in the higher-cost dol -- hours. And it also shows you that there isn't what we -- what we refer to as an on-peak/off-peak differential. So the differential between the pricing in the on peak and the pricing in the off peak.

(MOVED TO SLIDE 14)

MS. JOANNE FLYNN: So the next slide on monthly variability, I -- I had actually wanted to try and show the variability across all eight thousand seven hundred and sixty (8,760) hours in a year, but it just looks like one (1) big, blue blob when you try and do that.

So -- so the monthly information gives you the same sense that every hour is marked on there. This is the month of July 2012. So this is in chronological order. So you can see how the price is changing constantly, depending on the demands on the system and the load that requires -- that -- that needs to be served.

So we'll talk about the price in July being twenty-nine dollars and twenty-seven cents ($29.27), which is an average across all seven hundred and thirty (730) hours for the month. But what really is the price? At any given point in time it can be very different, and the price ranged in that month from seven dollars ($7) a megawatt hour to a hundred and sixty-eight dollars ($168) a megawatt hour, which is a huge variation in price.

MR. DAVID CORMIE: Now, I think the -- the important thing is -- to note is that -- that all load isn't served at that price. That's just the last -- the last little bit of load that's served at that price. Most utilities, like Northern States Power in Minnesota, have long-term fixed price contracts in place. So 95 percent of the -- 95 percent of the energy that is going to load is -- has been fixed.

This is just what the last megawatt -- the last -- the last 5 percent of load is being served.

So we -- that -- it's -- can you imagine if you were a utility and all your -- all your load was being served by this volatile price, well, how do you manage that risk? What happens if it stays up at two thousand dollars ($2,000) for a month? Like you can't do that. So they enter into a long-term fixed-price contacts either with -- you know, for their fuel or for a purchase agreement with Manitoba Hydro so they can -- they can minimize their exposure to this risk.

So less than 5 percent of the energy that goes to serve load is charged to the utilities at that market price. It's -- it's a -- it's a small -- it's a small percent. But that's the price signal that -- that MISO needs for economic dispatch so that the -- the -- so that there's a balance maintained between supply and demand in a -- in the -- in the five (5) minute market.

MR. BYRON WILLIAMS: It's Byron. It's really a follow-up to Dave's question, but I'm sure you can answer it more competently than -- than he can. Just -- just teasing.

When you -- when we use the term 'long-term contract', what are -- what are we talking now?

How long do long-term contracts -- would we expect the -- kind of the longest limit of those to run now, ten (10), fifteen (15) years? What...

MS. JOANNE FLYNN: Yeah, I mean, we -- we did have some in the portfolio that were thirty (30) years long. But basically -- Dave should answer this but base -- but I'll do it anyway.

Basically the -- the contacts are sort of in that ten (10) year range. But depending -- it could be ten (10) to twenty (20) years, depending on what type of product and -- and what -- what the customer is looking for, as well. So they are long term. When we talk long term, we really do mean long term.

(MOVED TO SLIDE 15)

MS. JOANNE FLYNN: Okay. So the next slide takes us into looking at costs by decision horizon. So this is from the utility point of view, somebody who has the obligation to serve.

And we've talked about the operating horizon. So it's very short term. So the decisions that are made in the operating hori -- horizon are ones where you're not making resource decisions. Your resources are set. Now you're going to operate with what you got as best you can.

So capacity costs are considered sunk. So whatever resources you've got, you use. Embedded capital costs are not in the energy price to reco -- they're rec -- recovered by other means than this MISO market price. That's what Dave was just talking about, that most of the utilities will have long-term arrangements in place, either for their own generation or for power purchase agreements with -- with other utilities that have surplus, like us.

So thermal generators will offer into the market a variable cost of production, and that variable cost of production would normally set the floor on the market price. So it shouldn't be going any lower than their variable cost of production.

When you look at the long-term planning horizon, now this is a point where the utilities have looked at it and they're going, Okay, load is still growing; we have -- or we have aging infrastructure, whatever their reasons are, they need to make some sort of investment in new generation.

So the capacity costs haven't been incurred yet. So now they're relevant to what we're looking at. The capacity costs aren't incurred, so they'll be considered along with how much it will -- it is expected to -- to cost a generator to operate.

The other thing they're going to consider is, what is the plant going to be used for? Are they looking for a resource that's going to run pretty much continuously, so a base load type of -- of plant? Or are they looking at something that's just going to fill in those peak hours that you saw on the price graph for a day?

Is -- are they looking for more of a peaking type of resource? So one (1) would be more -- more equivalent to using a -- a peaking type of -- of generation type, versus -- or a generator type, versus one (1) that is traditionally a base load generator type.

The other things they need to consider is the cost of transmission. We've been talking about, either you can have your resources close to the load, as long as you can get your fuel supply there, or you have to have your generators where the resource is, like wind; you have to put the wind where the wind is, and transmit the generation -- or, the generation, the energy to -- to the load.

And it's important to get the cost of the firm fuel supply in place as well. Natural gas is an example. You want to be sure that you -- you have access to the natural gas, and there's a cost associated with that.

DR. PETER MILLER: Peter Miller. What about throwing another turbine into a dam as an addition to capacity?

MS. JOANNE FLYNN: Well, when -- when the generating stations are designed, they're des -- designed to the optimal -- to the optimal size, based on the water regime that is there. So if you can put another unit on -- but it's a question of whether there's a cost effectiveness associated with putting that extra unit on. Because that's what a lot of time is spent doing in the engineering side of things, is figuring out what is the -- what is the right size of the generating station for the -- for the flow of the river that's -- that it's being built on.

MS. NICOLE FITKOWSKI: Erick Matthiesen has a question.

MR. DAVID LAMONT (VIA CHAT): I noticed MISO in January and April had approximately 10 percent energy from wind. How does MISO plan for wind?

MS. JOANNE FLYNN: Okay. Wind can -- in the last couple of years, the -- the rules in MISO have changed so that wind can be offered into the system as a resource. So on a -- on a day ahead basis, they're expected to offer their generators in just like any other generator does. But, as Dave spoke about earlier, when it comes to relying on wind from a capacity perspective, then that is considered separately from a reliability perspective. And that calculation, again, is done, I believe, by the generator submitting information to MISO, and it's calculated based on the peak hours of the day. And I believe it's -- it's somewhere in the neighbourhood of 10 to 13 percent that's being relied on from a capacity perspective.

(MOVED TO SLIDE 16)

MS. JOANNE FLYNN: All right. Moving on to slide -- the one (1), "Illustrative Variable Productions Costs from Existing Generation."

So what this does is, it shows you what the plant characteristics are. Firstly...

(BRIEF PAUSE)

MS. JOANNE FLYNN: Okay. So the typical heat rate across a coal plant -- and -- and I'm going to go through a couple of examples now of coal plants, combined cycles and simple cycles being contrasted by characteristics and costs.

So the typical heat rate in BTUs per kilowatt hour is ten (10) to the twelve thousand (12,000) for a coal plant, seventy-five hundred (7,500) to ten thousand (10,000) for combined cycle, and nine thousand (9,000) to thirteen-five (13.5) for a simple cycle gas turbine.

And, basically, this data is pretty representative of MISO. Over 80 percent of the coal generation comes from plants within that range. Over 80 percent of the combined cycles, as well as simple cycles, come from basically those ranges. So those are representative ranges of what we see in the market.

The non-fuel operating and maintenance cost in terms of dollars per megawatt hour, so keeping the plants running, four dollars ($4) a megawatt hour for coal, seven (7) and ten (10) for the combined and simple cycle. And then the emissions rates are -- are given here in CO -- tonnes of CO2 per megawatt hour. You'll see the coal plant is greater than a one (1) to one (1) ratio, whereas a combined cycle is in that point four three (.43) to point five nine (.59) range with the simple cycle having a higher range than that.

(MOVED TO SLIDE 17)

MS. JOANNE FLYNN: Okay. And now just to -- to show you the impact of -- on costs, on -- on market prices for these three (3) types of -- of generation in a lower sort of midrange and higher cost of fuel. So we are only talking about variable production costs here. We're not talking about a total cost for the generator including capacity; just the variable operating costs.

So the first chart shows you three (3) groupings, no carbon, with fifteen dollars ($15) of carbon, and then thirty dollars ($30) of carbon, and the dollars per megawatt hour on the Y-axis. And so these groupings are kind of stacked in the first no-carbon instance from the coal plants at lower and higher efficiency followed by the combined cycles at lower and higher efficiency, then followed by the combustion turbines, the simple cycles at lower and higher efficiency.

So without carbon, coal is a low-cost generator. These lower fuel graphs are at a natural gas price of three dollars ($3) per MMBtu and at a dollar sixty ($1.60) per MMBtu for coal. So that's considered a lower price for both of those fuels.

You can see as you add carbon, that of these thermal resources, the combined cycle, you see that emissions rate starting to have an effect and -- and giving you the -- the lowest of the prices for the thermal resources if carbon is applied at those levels.

(MOVED TO SLIDE 18)

MS. JOANNE FLYNN: If we go to the next slide, we move up to the midrange fuel price scenario, now we've got a natural gas at five dollars ($5) per MMBtu and coal at a dollar ninety ($1.90) per MMBtu. Again, with no carbon, all that's going to happen is the natural gas price goes up. The coal price does not go up in the same sort of proportion as the natural gas price goes up, and so the coal really looks like a low cost producer.

As you apply the carbon to it at fifteen (15) and thirty dollars ($30) per tonne, you see the prices rise, so that if you were to look at the combined cycle, you would see them in that order of forty (40) to sixty dollars ($60). And when you get to thirty dollars ($30) a tonne for the carbon, then you're getting to -- close to that sixty dollars ($60) a megawatt hour range for -- for the price.

(MOVED TO SLIDE 19)

MS. JOANNE FLYNN: So not surprisingly, when you go to the high fuel pri -- price example, it's just going to look that much more costly. So if there is a concern about carbon in the future, this is sort of what the outcome of that concern would be versus a no-carbon view of the future. So this is at a high -- higher fuel price at eight dollars ($8) per MMBtu.

(MOVED TO SLIDE 20)

MS. JOANNE FLYNN: Okay. This one -- this is an old slide. It's from 2007 information. But I want to use it because it was produced by MISO, and MISO hasn't produced another one since then.

So what this chart is showing is that what the cost of a generator is, is very much tied to how much you expect it to run. So the -- the curves that you're seeing on the slide are representative of the percentage of time the unit will run. And so it goes from -- from zero to 100 percent. And, basically, the higher the percentage of time a generator runs the lower cost per unit you will have.

Now, I will note that -- that on this chart it was recognized that the nuclear capital costs were significantly understated. But this isn't to be looked at in terms of -- of that exactness of representation, but more the shape of the curve.

We would expect a nuclear unit -- and it's there in red -- to -- to be a very high capacity factor plant, so it would run 90 percent of the time or more. So when you look at this chart you would go up from the 90 percent and say, Oh, okay, that's the price per megawatt hour that's most relevant for that kind of plant.

You'll notice wind is on there in green and it sort of stops. It stops around the 35 to 40 percent range and that's because there isn't any wind in MISO that can produce more than 40 percent capacity factor. So the best you can get for a price out of the wind is going to be at that 40 percent capacity factor level.

The other lines on here -- and I would draw your attention to the solid, I think they're blue and black lines, as opposed to the dashed ones, and those are -- those are natural gas generation. And they're for a simple cycle turbine. You don't really expect it to run more than about 25ish percent of the time. If you're going to run it consistently more than that, it would be more cost effective to put in a combined cycle.

So, again, at around that 20, 30, 40 percent range is the best dollars per megawatt hour you're going to get out of a simple cycle unit.

The combined cycle has more flexibility than that. They're often considered also a -- to -- to run in the on-peak hours. So that would be, you know, close to 50 percent of the time, but they can be loaded up to run up to 80 percent of the time. So they have a little more flexibility on that.

So what this chart is trying to show you is that it's -- it's really hard to say what the cost per megawatt hour of -- of a unit is, because it really depends on how you're going unit -- use it. But when we're asked that we usually give sort of those general types of -- of responses. But it's depe -- very much dependent on the capacity factor, how much it's going to run, and also on the -- the capital cost, and the associated discounting mechanism that you use for that.

(MOVED TO SLIDE 21)

MS. JOANNE FLYNN: So one (1) last slide for me and I'll turn it over to -- to Dave.

Other considerations that the US utilities have when they're considering new generation for the future, the -- the EPA regulations -- so this is the Environmental Protection Agency in the US, were quite actively bringing out restrictions on coal generations and new source performance standards, so what -- so providing some -- some very stringent direction on what's happening with -- with coal in the future.

Also, a utility owner has to be -- the owners have to be concerned about the age of their generation fleet, because almost half of the capacity is approaching forty (40) years of age. Forty (40) years is about the life -- considered to be the life of a thermal generating unit.

They're also concerned about diversification, because that protects them against the risks of things like climate change, legislation, these EPA regulations. So they're looking for that kind of diversity.

And an investor-owned utility is also seeking some form of investment opportunities. And in the US their -- their structure is such that constructing new transmission is something that can give them a rate of return.

Okay. I think I'm done and Dave is up. Are there any other questions?

MR. DAVID CORMIE: I guess, Joanne, that last chart of those curved lines, that was the all-in cost, right?

MS. JOANNE FLYNN: Yes.

MR. DAVID CORMIE: Yeah.

(MOVED TO SLIDE 23)

MR. DAVID CORMIE: So we wanted to talk a little bit about the MISO tariff. And our -- and the reason that's important is because when Manitoba Hydro exports title to the electricity transfers at the border to someone else, but there is no load at the border; you have to have transmission lines that connect the border to Minneapolis or the border to Duluth.

And the way that that electricity flows is over transmission lines owned by investor-owned utilities in the United States, but the rates for service for using those lines is covered by the MISO tariff. So those transmission owners, Northern States

Power, Minnesota Power, Great River Energy, they take all their transmission assets, their transmission lines, they give them to MISO and say: MISO, here's our transmission assets. You operate them. We need to cover our costs for running those transmission lines and -- but you can use them to serve load. And -- and if somebody like Manitoba Hydro wants to use them, you have to charge them something so that -- that -- you know, that we -- that we get -- that we get paid, 'cause their -- the cost of their transmission system has to be paid.

So the MISO tariff lays out the rules under which the transmission grid -- the MISO transmission grid is operated.

(MOVED TO SLIDE 24)

MR. DAVID CORMIE: Because MISO is a regional transmission organization. They're an RTO, and -- and that's one of their responsibilities. Transmission owners don't operate them. They own them. They maintain them. MISO collects the revenues and -- and dispatches the electricity over those lines.

So they operate the electric grid. Another thing that they do is -- is like Joanne said, you know, if we -- if we run the generator too much that transmission line will get overloaded. So when that -- when the loads on that transmission line, in real time, get to the point where the line is starting to be in danger, instead of keep adding load to the gen -- to the transmission, they'll start another generator that's closer even though it's more expensive. So they're responsibility is to operate the electric grid.

And -- and then they also have the responsibility under the tariff to provide transmission access. So when Manitoba Hydro says: You know, we got lots of water today. We'd like to get that electricity and sell it into -- into Minneapolis. Can we buy transmission service?

And MISO will say: Well, no, it's full today. There's nothing left; or, Yeah, there's some -- there's some -- some space on the transmission line. Manitoba Hydro, you can buy it.

And so they administer the access to the transmission line.

Reliability coordination is something MISO does. And that's saying that, You know what, that transmission line starts at Dorsey and it goes all the way to Minneapolis, and if you take your end of the line out of service to do maintenance, well, we ought to know about it because that line is going to affect the reliability of our transmission system in -- in the United States. So we've got to be coordinated. So you have a coordination agreement. Let's not take any units out of service that we don't know about, and let's study all these situations.

And so MISO acts as the reliability coordinator to transmission organizations like Manitoba Hydro who are outside the MISO footprint.

And they do efficient market operations. You know, my power traders can only phone so many people to make a transaction. In -- maybe in an hour you can talk to six (6) people. Well, that doesn't work very well. It's not -- not as efficient as if MISO was doing all the dispatch.

So MISO is -- is figuring out what's the most efficient way to operate the generators. So they -- they run the market rather than having what was -- used to be in the old days, a bilateral market. You did it on the phone. You phoned a few people. You found out what's the -- you know, what -- what do you want to charge me for my power? And -- and, you know, that -- that's the way it used to be done.

But now it's much more efficient than that. MISO can dispatch all the generators in the --

in the region and -- and lower the cost of electricity to everybody through efficient market operations.

And they coordinate regional planning. So they make sure that -- that transmission plans that are put in are the right plans, and not something that's just in the interest of a single utility.

(MOVED TO SLIDE 25)

MR. DAVID CORMIE: So the -- all those rules about those -- those six (6) items that I talked about, are -- those rules are laid out in the MISO tariff. It's a document, and it tells everybody how the -- the MISO system will be run.

As part of the tariff, they also calculate how much spare transmission, or unused transmission capability, is on the system. And they do that under an open access transmission tariff.

Open access being everybody can take service. It's non-discriminatory. It used to be Manitoba Hydro could say, We're going to hold that transmission for our own use; you can't use it. So we would be discriminating against somebody like Saskatchewan from using our transmission. You know, just -- just hoard it. Don't let anybody have market access.

Under an open access transmission tariff, it has to be non-discriminatory. Manitoba Hydro has to offer service to everybody on the same, equal terms and conditions. And it doesn't matter whether it's SaskPower, or Manitoba Hydro's merchants, or Northern States Power, everybody has access under an open access transmission tariff.

And we will calculate the available transfer capability on a non-discriminatory basis. If there's a hundred megawatts available, first come, first serve. You just have to pay for it according to the rates that are set out in the -- in the tariff.

And so they -- they evaluate and approve all requests for service. And those requests can be for hourly -- I want transmission service for -- for the next hour, or it could be for tomorrow, or it could be next week, next month, or -- or for a year. There's lots of different time-frames in which you can ask for transmission service.

So if we're in a period of high water, and Manitoba Hydro needs transmission service for six (6) months, we'll go and ask MISO for firm transmission service for six (6) months. They'll run through their computer models and say: You know, there's only 15 megawatts of firm transmission service available. Oh, okay, well, we'll buy that.

And -- or they may say: No, it's all -- it's all been allocated. There's no firm transmission service. Okay. Then we have to take non-firm service.

So they perform transmission impact studies. And in the case of Manitoba Hydro wanting to sell to Minnesota Power 250 megawatts, MISO says: You know what, there's no spare long-term transmission available. If you are going to consider a power sale from Manitoba to Minnesota Power, you'll have to build new transmission. And this is the impact of you trying to sell that power.

And they'll tell you what those -- that transformer is too small, that breaker is too small, you need to have these facilities. And they'll tell you what those costs are going to be to -- on the system, to getting it up to the standard necessary so that an additional 250 megawatts can go to the United States.

And they communicate with all transmission customers on the Internet, in an open fashion. It's -- it's completely transparent. Nobody has access to information in -- in confidence. All of the information that they make available, the transmission, is made available to anybody at the same time, on an -- on the -- on -- it's called 'the oasis'.

So they administer the open access transmission tariff, and -- what's the next thing here -- and they coordinate the use of -- of the transmission system among other regions. So MISO has a footprint, but MISO is connected to PJM. Well, there's flows of electricity between those two (2) regions. So MISO ensures that flows -- or the -- the activities on the -- between regions are coordinated.

And then they operate the energy and operating reserve market. And Joanne went through that. You make your offers on a day-ahead basis. MISO evaluates that. It sets in plan -- it sets in place a plan for how the load is going to be met tomorrow. Everybody gets paid based on that plan. And then they turn it over to the real-time operators, and -- and, if everything goes according to plan, people operate their generators according to that plan.

But if things are different because the load is higher than it's forecast, or generators aren't available to work, there's a real-time market to -- to balance the available supply and demand. And you see prices that we saw in the pricing map as a result of those kind of real-time ev -- events.

And they're the balancing authority for all the load in the MISO footprint. They balance the -- the operation of the generators with the -- the amount of load that there is. And they try and keep that balance within every five (5) minutes. They've got to make sure that every five (5) minutes there's enough generators generating to meet the load.

So when you turn off your switch, your -- in your house, and you stop using electricity, somebody has to actually turn a generator down. They have to -- they have to balance the load, because you stopped using electricity. Well, who's -- who's in charge of making sure that the generator is shut down? That's what a balancing authority does. They stop generating when the load goes down. And when the load spikes they're responsible for bringing the -- the generator online.

Manitoba Hydro is a balancing authority. We balance supply and demand in Manitoba. MISO does it for the MISO footprint. Saskatchewan does it -- is a balancing authority. They balance the supply and demand moment by moment of load and generation in Saskatchewan.

And we talked about the day-ahead and real-time operating reserve market.

(MOVED TO SLIDE 26)

MR. DAVID CORMIE: So what is transmission service? It's the right to use the transmission grid to ship electricity. And there are different types of transmission service available. You, as electric customers, are taking transmission service, but it's -- but you don't have to do anything. Manitoba Hydro provides that service for you. It's called network service and it's built into your rate.

A general service large customer in Manitoba Hydro's footprint pays about 15 percent of its bill to Manitoba Hydro to operate the transmission service so that they get their electricity, and that's called 'network service'.

And you don't actually identify what specific facilities are... So network service is -- it's like a -- it's based on cost-of-service. So if you understand cost-of-service principles where the cost of -- of putting the transmission facilities in place for your network load, it's done on a pro rata cost sharing basis. It's very similar to the principles that we use in rate making in Manitoba. That's how network service is.

And -- and utilities don't have to actually arrange for that. MISO just provides that as a matter of course. And it's used to serve network load, large industrial customers, retail customers. And that's -- and -- and you can -- you can mak -- you can buy that from MISO if your load was in -- in the MISO footprint.

The other type of transmission service that's more relevant to Manitoba Hydro is called firm point-to-point service. I want to ship my power from the border to Minneapolis. One (1) point is the border, one (1) point is Minneapolis, so it's called point-to-point. It's like when you fly on a -- on an airline. You take point-to-point service. You go from London to -- to Toronto, point-to-point service. The same principle applies in electricity and it's used for wholesale power transactions.

So when Manitoba Hydro sells 500 megawatts to Northern States Power we sell it from Dorsey to the border. We take point-to-point service under the Manitoba Hydro tariff for 500 megawatts, and then Northern States Power will take point-to-point service from the border to Minneapolis under the MISO tariff, 500 megawatts of transmission service.

And -- and that's how bulk transmission

-- bulk -- bulk electricity is shipped across the grid, using point-to-point service. There are seven (7) priorities of transmission service. Network service is the highest. So everybody's obligation is -- firstly is to serve their load. So network service is priority 7.

If you're using point-to-point -- point-to-point service is of the same quality. It's used to serve a firm load. And so when we talked about having an import contract, if the import contract is on firm transmission, MISO will use that transmission to serve Manitoba's firm load, giving it the same priority as they use -- as they serve their own network load. So that's why we can call that -- those imports on firm transmission a dependable supply, because it's -- it's -- it has the highest priority of transmission service.

If you can't get a -- if -- if point-to-point transmission service isn't available then you have to go to the -- to the non-firm point-to-point. And there are five (5) different types of priority 1 to priority 5, and that depends on whether you're buying it by the hour, by the day, by the week, by the month, or by the year. The longer the term transaction the higher priority it is.

But what non -- non-firm point-to-point

service, it's like getting an airline ticket with Air Canada and you go there and you say, you know, I want my seat and they, Well, we oversold. You get bumped. So even though -- but Air Canada charges a full price, here you get it at a discount at least.

So the -- the price that you pay is depending on the priority and the next slide actually talks about what those prices are.

(MOVED TO SLIDE 27)

MR. DAVID CORMIE: Who sells it? Anybody who operates -- is a transmission -- has a transmission tariff, like Manitoba Hydro, SaskPower, MISO, or other transmission owners are -- offer transmission service. How much does it cost? We've talked about that. It's built into network services built into your bill point-to-point. It depends on where -- where you're going from and where you're going to. It's like an airline ticket.

It costs fifty-seven thousand dollars ($57,000) a megawatt year to buy point-to-point service from the border to Minneapolis under the -- under the northern -- to -- to deliver it to Northern States Power. So if you were buying point-to-point service for 500 megawatts, you take five hundred (500) times seven hundred (700), five -- fifty-seven thousand (57,000), and that's the cost of providing that firm transmission service.

If you were -- if you were to ship it from the border to Minnesota, they have a different price. It's more -- more like thirty thousand dollars ($30,000) a megawatt year.

So you look up under the tariff. You find the points that you want to go. It's like an airline ticket, and you just -- you can figure out what the rate is. Non-firm, the -- it depends on -- the units are different. Hourly transmission is by the megawatt hour. Monthly is by the month, you know, thirty-four hundred dollars ($3,400) a megawatt month. But again, this is a very low quality service. And you may pay for it but you may never get to use it because you were interrupted.

Can others use your transmission service? So if Manitoba Hydro goes and owns point-to-point, can we do anything with it if we don't need it? Then we can sell it. If somebody else -- we -- and it can be sold in the after-market, or it can be assigned.

So let's say that we bought transmission service because we thought we were going to have a high water year, we don't need the transmission service and we're importing instead of exporting. No, we have a -- we can go to the market and -- and sell our point-to-point service to somebody else and they can use it.

MR. BYRON WILLIAMS: I --

MR. DAVID CORMIE: Yes, Byron?

MR. BYRON WILLIAMS: Thanks, Dave. I just missed the distinction between network and firm point-to-point in terms of priority, so I'm sorry to ask you to repeat, but I -- I didn't quite understand it.

MR. DAVID CORMIE: Network has the same priority as firm -- as firm point-to-point.

(MOVED TO SLIDE 28)

MR. DAVID CORMIE: So what happens at the border? In jargon, we call the border seams. Seams are where one (1) regional transmission organization butts up against another. So this is where Manitoba Hydro's transmission network stops and the MISO starts, or where the Saskatchewan -- you know, the Saskatchewan and Manitoba border.

In Canada, those are at the geographic boundaries. In the United States, it's not. They don't follow geographic boundaries. They -- it's just -- it's depending on where the service territory would be.

So you -- you've seen that map of the MISO footprint. It's -- it doesn't really match any geographic -- sometimes it does -- boundaries but not necessarily. It generally is where -- whether the service territory of that utility goes to the next utility service territory.

So we've got the Manitoba-Saskatchewan seam. We've got the Manitoba-MISO seam. We've got the Manitoba-Ontario seam. There's the seam between MISO and PJM. There's the seam between PJM and New York. So you can move power -- we can move power from Manitoba across into Ontario, across into New York, into PJM. You can follow all those seams. But the question is: Can you afford to buy the transmission service all the way across?

Transmission service is required on both sides of the border because there is no load at the border. We can deliver our -- we can deliver our power to the border, transfer -- title transfer at the border, but the utility who's buying it needs to then move it from the border to their load.

Right now, Manitoba Hydro owns twenty

(20) long-term transmission service reservations under the Manitoba Hydro tariff. So all of the firm transmission capability between Manitoba and MISO is held by Manitoba Hydro, is owned by Manitoba Hydro in Manitoba, so. And we do that under twenty (20) different transmission service reservations. And those are held under the transmission tariff. We pay for them but Manitoba Hydro's transmission company gets the revenue.

So, in effect, Manitoba Hydro merchants are paying Manitoba Hydro transmission. So no cash actually transfers but we buy the transmission service as if we were any third party.

We also own ten (10) long-term transmission service reservations under the MISO tariff. So you can see on this chart there's a blue arrow pointing north in Minnesota, the orange arrow pointing south. The orange arrow pointing south would be a transmission position held by a US entity. But the blue arrow pointing north says Manitoba Hydro owns the transmission reservation for -- in MISO to bring the power from Minneapolis to the border.

So we own it from Minneapolis to the border, and then we own it in Manitoba. So the -- the one (1) -- there are -- there are ten (10) transmission reservations in the US that Manitoba Hydro owns.

We don't own the transmission line. We have the right to use the line. And we have the right to use it on a priority 7 basis because it's -- it's firm transmission. So we can then rely on that transmission in MISO to serve our load in the same way we can rely on our own transmission to serve our load.

All we need then to complete that transaction is to have a generator in MISO. So we need to have a contract with a US generator to commit that power, and then we'll put it on our firm transmission and we'll bring it to Manitoba, and then we'll use it on Manitoba's transmission to bring it into our load.

So you can see that you have to have the package of generation and transmission in order to have firm transmission, and -- and we own transmission service in the United States to do that.

As well, we own transmission service in the United States for exports. So we own about 60 percent, almost -- I think 700 megawatts of the 1,900 megawatts of export capability -- it's in Manitoba Hydro's name. And we control the use of that transmission.

And then on a daily basis there are many short-term transmission reservations. So high water you might want to have more transmission so the power traders will go buy a -- buy transmission service, whatever is available, in order to make sure that our electricity doesn't get curtailed.

Manitoba has a coordination agreement with MISO. So not only do we coordinate the operation and the -- from the relia -- the transmission system reliability but we also coordinate the tariff, the rates, so you don't pay for transmission service twice.

So the tariff of the load applies under our agreement. So let's say that we're importing. Who is our load? Our load is our Manitoba customers. So MISO says, We won't charge you, Manitoba Hydro, for using the MISO transmission system to bring power to the border because your customers are paying for the transmission service already in Manitoba. You only have to pay for transmission service once.

So MISO waives their transmission charges under the coordination agreement. Likewise, when we're serving MISO load the MISO customer is paying for transmission service under their tariff so Manitoba Hydro waives our transmission service so that there's no pancaking of -- of tariffs. And that's very beneficial for -- for Manitoba Hydro to do that because we're exporting way more than we import.

So the -- the value to us of -- of having the tariff in the United States -- or we're exporting way more so the -- the benefit to us is much greater than -- than the -- than the cost of lost transmission service in the -- in the opposite direction.

Okay. I probably confused you a lot about that. If there are any questions after lunch I can tell you about that, unless there is questions now?

(BRIEF PAUSE)

MR. ED WOJCZYNSKI: No questions? No comments on anything that was talked about this morning? Yes, Regis.

MR. REGIS GOSSELIN: David, the -- the -- Manitoba Hydro is an associate member of MISO, and could you explain to me why that is as opposed to say, for example PUB is a member of OMS and -- and you're an associate member. Now -- now, is there some historical basis for that decision?

MR. DAVID CORMIE: We're a coordinating member and we are a market participant. So in -- in a coordinate -- in a coordinating member we coordinate our operation of our transmission system in Manitoba with the operation of the transmission facilities in the United States.

But -- but we haven't turned the actual con -- the facilities over to MISO to operate. We've just agreed to coordinate our activities. And the reason is is because we're in a different country than -- than MISO. MISO is in the United States. So for sovereignty reasons, under the Manitoba Hydro Act, we have to maintain control of the operation of all of the facilities in Man -- yeah, in Manitoba.

So we're -- there's probably not a lot of aff -- effect of that except legally we're -- we're complying with -- with the laws of Canada. But, you know, that's -- we -- we have to maintain control of our -- of -- of our facilities. We can't turn that control over to another jurisdiction.

As far as a market participant is concerned, we behave exactly as any market participant in MISO. So we can -- we -- there are no restrictions on what Manitoba Hydro can do in the marketplace. We offer our surplus in, we can buy out of the market, just as any -- anybody. So we're a full market participant. We use all the financial instruments that the market makes available. Billing and all that is -- it -- it -- you couldn't tell that Manitoba Hydro wasn't in the market.

The other major difference is our load is served from Manitoba generating stations and we determine how much surplus we actually take to market. Wherein, if -- if it was under MISO's control, MISO would decide where our -- where our load was being served from, what generators would be operated. Manitoba Hydro does that independent of MISO.

And that -- although the -- the power traders do the planning for the day -- for -- on the day ahead, the real-time operation and the dispatch is done by the control centre with the sole purpose of serving Manitoba load first, and then whatever is left over the surplus actually goes to market.

MR. BRUCE DUGGAN: Bruce Duggan from Providence. Can you -- I hope this isn't too big a question. Can you talk about how our relationship with MISO compares to say, Hydro-Quebec's relationship with their American counterparts, or BC? Is it typical? Is it unusual? I'm sorry if this is too broad a question.

MR. DAVID CORMIE: Both Hydro-Quebec and BC Hydro have US subsidiaries, or they have subsidiaries that -- that participate in -- in the market. Manitoba Hydro does not have a US subsidiary. We transact at the border, so that's -- that's a -- a difference.

BC Hydro, under their -- in their -- with their PowerX subsidiary, is actually a -- a participant -- is actually -- trades electricity in the United States for non-utility reasons. And so they -- they manage the BC Hydro surpluses, like we do. But then they also manage British Columbia's assets that they own under the Columbia River Treaty in Washington because they -- you know, they are entitled to a certain amount of generation. And so they have to -- they have to be in that market because they own electricity in that market.

And then, thirdly, they -- they enter into -- they're a trading organization. They buy and sell in the market. So Manitoba Hydro doesn't have any generation assets in the United States, so that's what separates us -- differentiates us from PowerX.

Quebec-Hydro is very much like Manitoba Hydro, except that they have a US subsidiary that buys the electricity from the utility and markets it in the United States as an indepen -- as a -- as an independent organization. And they -- they may own transmission assets in order to do that.

Manitoba Hydro stops at the border. And although we -- we may have transmission service reservations in our name -- it's like when you go and rent a car in the United States at the Minneapolis airport, it doesn't mean you own the car. It's -- and -- and you have a rental agreement. That's the same relationship Manitoba Hydro has when we rent the use of the transmission lines. We go and we -- we have these rental agreements. But it doesn't create a permanent establishment for Manitoba Hydro in the US, where PowerX and -- and Quebec-Hydro do.

Both those organizations are -- are probably subject to US regulatory oversight, and US tax laws. Man -- because Manitoba Hydro trades at the border, we're -- our -- we're not subject to -- to regulatory or tax issues in the United States. And that's the reason why we -- we -- we've kept it at the border. We -- we don't want to be FERC jurisdictional, and we don't want to incur any -- any US state or federal taxes.

MR. ED WOJCZYNSKI: Any other questions? We still have six (6) minutes. Our -- congratulations to our two (2) presenters to being so efficient. But, seriously, any more questions?

DR. PETER MILLER: This goes back to Joanne's presentation on slide 20 -- 21. Other considerations for US utilities, under diversification it says:

"Coordination challenges utilizing
more gas generation due to coal
retirements."

What does that mean?

MS. JOANNE FLYNN: So what that is referring to is that same slide talks about EPA regulations at the top of the slide. Where -- where should I be standing? I don't know. Okay. And what that -- what effect that's having on the MISO jurisdiction is that there -- there's anticipated retirements of coal units in the order of 6 to 12 gigawatts across the region, so 6,000 to 12,000 megawatts of coal over time.

And so what that means is there's an expectation that that will be replaced with -- with natural gas generation so that there'll be more natural gas generation running than -- than we are seeing today. And so the -- in the future, that's -- that's what they're looking at. Where's that slide again?

So the coordination challenge is -- is to -- to ensure that they have the gas supply to do that, as well, so -- so it will require some.

(BRIEF PAUSE)

MR. PETER MILLER: What's being coordinated then is gas supply to -- for generation?

MS. JOANNE FLYNN: That -- that's part of it. But it -- it's also just the whole change in their -- their generation mix.

MR. PETER MILLER: Is hydro plus wind a competitor for that scenario?

MS. JOANNE FLYNN: Well, not to the tune of 6 to 12 gigawatts. But they -- they are looking at -- like when they talk about -- when we talk about diversity for the -- for the US -- for the US utilities, they're looking at whatever -- whatever range of -- of resources are available to them. And in some of the states the wind regime is just not that good.

But that is part of the benefit of -- of trying to get a major new interconnection into place, is to allow -- to allow for more of the hydro energy to -- to go into that region.

MR. PETER MILLER: And going into the -- the larger question, can we go more into the capacity business to firm wind?

MS. JOANNE FLYNN: Are you talking about in Manitoba or are you talking about --

MR. PETER MILLER: Yeah. I mean, with

--

MS. JOANNE FLYNN: Oh.

MR. PETER MILLER: Instead of selling base load, how about firming wind as -- as a strategy? Yeah. And this may go beyond your presentation, obviously.

MS. JOANNE FLYNN: Well, we've looked at a wide range of resources. And having -- having wind backed by capacity is -- is one (1) of the -- one (1) of the plans that we have looked at. What -- what we see is that it'll probably take a few more years before it's really cost competitive. So, yes, it is possible to look at -- at using capacity to back wind sometime in the future.

MR. PETER MILLER: On either side of the border?

MS. JOANNE FLYNN: Yeah. Well, basically, it's -- it's -- yes, on either side of the border, I suppose. But basically, in the US, they have a lot of -- of their own wind, and so they're -- they're going to develop the wind there. It's -- it's also combined with it being an economic -- a driver for their own regions. So then the capacity issue becomes a little more complex but can be somewhat dealt with depending on what sort of market arrangements are in place for capacity.

MR. DAVID CORMIE: Peter, the -- the extension to the 500 megawatt sale to Xcel in 2015 was justified as a resource by Northern States Power as exactly what you said. It's a hydro-wind combination, and wind providing half the energy and -- and the purchaser, Manitoba, providing the other half of the energy and the capacity. The mandate in -- in Minnesota is that Xcel needs 30 percent of their retail load served by renewable resources in Minnes -- that -- that are available in Minnesota by 2025, so they're forced to build wind.

And then they said: Okay. And what we'll do is we'll evaluate the wind-hydro combination as a base load resource, and that's -- that's -- that -- that was exactly what -- what you said they were doing.

But they're forced to put in -- put in -- in wind. So having got the wind, recognizing that it has limited capacity value, they have to put a capacity resource. The alternative to that was to put wind with the combined cycle combustion turbine. And compared to the product that Manitoba Hydro offered them, there were significant value to go with the hydro-wind rather than the hydro-gas at the time.

And as far as in Manitoba, when we do the evaluation of wind, we give the full benefit of the -- of the hydro resource to any Manitoba -- any Manitoba wind development. So we're not -- we haven't carved off or sold that -- that capacity to somebody else. We don't sell the physical storage services to out -- outside of Manitoba for firming. It's -- it's just -- it's not done. We reserve it all for the benefit of Manitoba wind, and that's been policy for -- for, I don't know, ten (10) years now.

MR. ED WOJCZYNSKI: Nicole...?

MS. NICOLE FITKOWSKI: Dave Lamont has a question.

MR. DAVID LAMONT (VIA CHAT): I have one (1) question in the previous set of slides. It was said that Manitoba Hydro plans on the basis of the lowest water flow recorded ever on its system. Is that a standard operating procedure for all the utilities? Is it a choice of Manitoba Hydro? Is it a regulation? What is the basis of that position?

MS. JOANNE FLYNN: The -- I'll go back to the -- the NERC requirement for reliability. And in it they recognize that an energy constrained system may wish to have some form of criteria in place that reco -- recognizes the -- the energy constraint of the resource.

And hydro is one (1) of those types of resources. So what is expected is that something like the lowest flow on record as a limit for relying on dependable energy would be used, and there are some similar examples in -- across the hydro utilities. But hydro systems tend to be somewhat unique, but there is a similar type of constraint that would be in place on utilities that are predominantly hydro.

MR. DAVID CORMIE: We're fortunate that we have a long-term -- a record of long enough duration to describe the risk of drought. If you were -- if you were a utility like Quebec Hydro, their water flows starts somewhere in the 1940s, and so, you know, when I started with Hydro they had a very short record, and -- and they had to go into some synthetic -- you know, some probabilist ways of managing the energy risk. But Manitoba Hydro is very similar to other companies who have the long-term records available. That's the basis of their design. It's pretty standard industry practice.

MR. ED WOJCZYNSKI: Got a question here.

MR. BRUCE DUGGAN: Hi, Joanne. You made a comment right at the beginning of your presentation, I -- I think, that -- something like because there's going to be more demand we have to produce more capacity. And --

MS. JOANNE FLYNN: What -- what I -- yes? Is that your question?

MR. BRUCE DUGGAN: No, no. My -- am I remembering it accurately?

MS. JOANNE FLYNN: Not -- not quite, but it's pretty close though. What I -- what I said is because load is continuing to grow, there need to be resources to serve it. So utilities will be looking at generation sources to serve that load.

MR. BRUCE DUGGAN: Okay. Am I right in assuming that we're going to get the rationale this afternoon for why that belief -- I mean, that undergirds the whole process, right?

MS. JOANNE FLYNN: Yes.

MR. BRUCE DUGGAN: That belief undergirds --

MS. JOANNE FLYNN: Yeah.

MR. BRUCE DUGGAN: -- the entire process?

MS. JOANNE FLYNN: It -- so there will -- yes, there will be a presentation on load this afternoon.

MR. BRUCE DUGGAN: Okay.

MS. JOANNE FLYNN: Yes.

MR. ED WOJCZYNSKI: We have hit that time-line, so I suggest unless there's any burning questions now that we take a break for lunch. And given that we actually are on time, I -- I would suggest we stick to the one (1) hour, and -- we'll let's say fifty-five (55) minutes -- and come back at 1:15.

Is that -- is any -- everybody -- does anybody have a problem with that, or other way?

Okay. Lunch. There is lunch available next door, just outside the door on this side where I am. And you can -- actually have two (2) choices. One (1) is just bring it back in here. The other is if you carry down the hallway there's some doors to the outside and there's a patio on the roof there, next to our green roof, by the way. Although, it could do with a bit of water, I think. And so you have a choice of just coming back in here, or going out on the patio.

So I suggest we take our break now. And for those who are on the external, we will come back at 1:15. Thank you.

--- Upon recessing at 12:20 p.m.

--- Upon resuming at 1:21 p.m.

MR. ED WOJCZYNSKI: Hello. If we could get started again. Before Dave -- we're going to start off this afternoon with Dave on the export contract fundamentals. But before we do that, maybe, Nicole, could you just mention who is on the externals just for everybody else to know?

MS. NICOLE FITKOWSKI: So currently we have Bill Harper who is still logged in, Dave Lamont, Erick Matthiesen, Paul Chernick, and that's it.

MR. ED WOJCZYNSKI: Okay. Thanks. I guess we just get going. It's all yours, Dave.

PRESENTATION RE: EXPORT CONTRACTS FUNDAMENTAL TO PREFERRED PLAN:

MR. DAVID CORMIE: Okay, is my slide presentation available? There we go.

(BRIEF PAUSE)

MR. DAVID CORMIE: Okay.

(MOVED TO SLIDE 2)

MR. DAVID CORMIE: I wanted to spend a little time this afternoon talking about export contracts in a generic ter -- in a generic sense. And then I'm going to end my presentation talking about the Minnesota Power 250 megawatt sale agreement in a bit more detail.

Whether we talk about the Minnesota Power product, the NSP product, the WPS sale, essentially they're all the same system participation of power. And -- and rather than go into them all in -- in gruesome detail, we'll just deal with the MP contract.

And our -- our customers buy long-term firm power to displace the construction of their own generating facilities. And as Joanne mentioned this morning, when they're making that decision they're considering the capital investment that they may have to make, what it would cost to operate that facility.

And so, you know, Manitoba Hydro just can't dream up a price when we go to market and say, This is the price. It has to be competitive to those alternatives because those utilities are either issuing an RFP, they've got a whole bunch of quotes, and Manitoba Hydro has to be competitive. And -- and if it's not done through an RFP process, it's done -- it's negotiated.

And then the customer will take that product to the market and ask its other suppliers whether they can beat Manitoba Hydro's product and service offering. And to the extent that was done with the NSP sale, nobody could com -- nobody can compete because they don't have the hydro alternative as an option.

And so I just want to start with this chart. This chart shows Manitoba and export demand. I think this was a -- this is a week in June showing hourly loads, starting at midnight on Monday morning, going to midnight on Sunday evening.

And these are all the loads that we were serving. The -- the lower chart illustrates the Manitoba load demand. And you can see Monday through Friday. This dark blue area at the bottom is -- you know, every day of the week, it's pretty well the same in -- in the summer. And then Saturday it drops off a little bit. And then Sunday, less load, as there's less industrial and commercial activity.

And on top of that we've stacked the export sales, and they're generally the three (3) types. These long-term forward contract sales, a customer buys 500 megawatts starting at seven o'clock

in the morning, 500 megawatts. That 500 megawatts is
constant for sixteen (16) hours a day, and at eleven
o'clock at night, it goes to zero. It's a block of
power. And -- and those are -- those are the ones that
are shown as the forward sales. They're the long-term
forward sales.

And then above that I'm showing two (2)
types of MISO spot market transactions: the day ahead,
so the ones that we commit on a day-ahead basis; and
then there's some real time. And you can see the real
time is just, you know, little scraps, The little --
the -- the little bits of power that we have left in
real time that our system control centre may have said
to us, You know what, we can't give you everything on a
day-ahead basis, because we need to hold a bit of that
in reserve. But once you get into real time, the
control centre says, You know what, we're okay; You can
have the last scraps of surplus. And -- so the day
ahead is -- is really it's just a -- a salvaging of the
-- of the load forecast on a certain day. And so you
end up with this -- this profile.

In this case, the -- there's a mix of
long-term forward contracts. The Monday-to-Friday
sales are -- are pretty well constant. And then some
of the contracts, we're not required to deliver on the

weekend, so you can see that they peel back for Saturday and Sunday.

But in a -- what -- what we're -- what we're going to talk about this afternoon are those forward contracts. And you can see that they make up a considerable portion of the summer, or summer load obligation. So imagine in the wintertime, instead of having 2,500 megawatts of Manitoba load, you've got now a thousand megawatts more of heating load, and it's darker. So that -- that dark blue area would -- could be up around 3,600 megawatts, because there's more winter demand.

And so we won't have as much -- many sales in long-term forward sales in the wintertime, because in the summertime, we're delivering our long-term firm power, plus our seasonal diversity obligation. In the winter we don't have the seasonal diversity obligation. So we -- we, in effect, fill in the load profile in the summertime, and -- and back it down a little bit in the wintertime.

But you can see that the -- the other interesting thing is there's -- there's very little long-term firm sales at night. Customers don't need power. If they need power, they could just go to the market. And so our load profile is mainly driven by this five (5) by sixteen (16) -- five (5) days a week, sixteen (16) hours a day, this big block of -- of power that's -- that's sold.

(MOVED TO SLIDE 3)

MR. DAVID CORMIE: So the -- the recent major long-term contracts that are in the preferred development plan are with three (3) companies: Northern States Power, Minnesota Power, and Wisconsin Public Service. The -- the first sale goes from -- is an extension of the existing sale that expires in 2015: 325 megawatts in the wintertime, 370 meg -- 5 megawatts in the summertime.

In the summertime we deliver the energy sixteen (16) hours a day, Monday to Friday. In the wintertime, it's twelve (12) hours a day, at a rate of 325 megawatts. So it's, again, it's just a block -- a block of -- of energy delivered at the border and in -- in those hours.

And then on top of that, Manitoba Hydro has the option, starting in 2020, to sell Northern States Power 125 megawatts of additional power, bringing the total quantity up to 450 megawatts in the winter and 500 megawatts in the summer. And it is

Manitoba Hydro's option, if Manitoba Hydro deems that it has the surplus available, we -- NSP is required to -- to buy that 125 megawatts for those four (4) years.

And I think we have to -- and it's conditional on -- there's condition precedents saying that it's subject to Manitoba Hydro building new -- committing to new generation. So if we are to commit to Keeyask, or it may be a condition precedent that we can waive if -- if we still have that surplus without Keeyask, that we can enter into that 125 megawatt sale.

And those sales go to -- to 2025. Our -- our relationship with Northern States Power began back in 1976, with large blocks of power sales. Right now we're selling about 900 megawatts in the summer and five hundred (500) in the winter. And we expect in 2025 that, for the fourth or the fifth time, we will roll those transactions over and continue to serve them as long as we have surplus capacity available.

What's interesting about the NSP sale agreements is that they're -- they don't consume any dependable energy resources in Manitoba. The -- in addition to the sale agreement, we've signed the seasonal diversity agreement which extends the seasonal diversity arrangement starting in 2015, going to 2025, for 350 megawatts in the -- we'll see them 350 megawatts in the summer and we get 350 megawatts back in the winter.

And the -- and the -- there's clauses in the agreement that say, Under adverse water conditions, Manitoba Hydro can purchase all the energy it needs to serve the sale obligation from Xcel -- or from NSP. So it doesn't consume any -- any Manitoba energy resources to serve the sale. We have the option of buying the energy that we need to fulfill our obligations to NSP from NSP. So in effect, they're self-sup -- they're backstopping the sale under drought conditions.

And -- which is -- which is a great option for Manitoba Hydro, because as our load forecast comes and goes -- some years it's higher, some years it's lower -- we don't run out of energy resources to serve that -- to -- to serve the NSP sale. NSP says, We're so low on energy in the wintertime, we can send you the energy you need to -- to meet your energy obligation back to us.

And so it's -- it's a very good product for Manitoba Hydro. In effect, they've taken on the -- the drought risk associated with energy supply.

The second agreement is a 250 megawatt transaction starting in June of 2020, going to 2035, with Minnesota Power. Joanne spoke this morning about

Minnesota Power -- or about Minnesota utilities and the utilities in MISO.

Minnesota Power is a -- is a great example of a utility that's over 85 percent coal based right now. And their strategy is to transform themselves by 2025 into being 50 percent. So they're going from being essentially 100 percent coal and natural gas to being 50 percent renewable and 50 percent carbon based.

And -- and what -- a major component in their ability to do that is the sale agreement with -- with Manitoba. In addition to that, they're investing in wind resources in North Dakota and buying some transmission to bring the wind from North Dakota to Minnesota.

But this is a company that's clearly concerned about being able to continue to -- to burn coal, the cost of upgrading their coal plants, and -- and has a strategy. And -- and I think we were very successful in getting them to start thinking ten (10), fifteen (15), twenty-five (25) years down the road of having a hydro component in their portfolio.

And even if the -- when the contract ends in 2020 -- in 2035, the transmission line that will be built as part of this transaction will still connect them to Manitoba, and they'll still have access to the hydro energy.

And so the transaction just allows them to invest in transmission to -- to be able to access that hydro energy that's available ninety-four (94) years out, or ninety-seven (97) years out of a hundred. And then they'll -- they'll deal with the capacity issue if it comes up but they've got a pipeline right into the heart of -- of a very predominant hydroelectric utility and they can always count on hydro energy in perpetuity.

So it's critical for them to have this strong connection with Manitoba Hydro, and -- and they've -- they -- they have bought 250 megawatts from us. And this transaction, it's seven (7) days a week, sixteen (16) hours a day, and -- because that's the nature of their base load. They're -- they're large mining loads. The mines work seven (7) days a week. And their capa -- their load factor on their system is very high. It's above 85 percent. So they don't have a big winter peak. They don't have a big summer peak. It's just a cons -- relatively constant load. So they need a resource that's constant over time.

Byron...?

MR. BYRON WILLIAMS: Yes, Byron

Williams. Dave, do you have -- we have moral certitude now about the Canada/US transmission line, like it's -- it's a go to Minnesota Power, or what's its status?

MR. DAVID CORMIE: The -- the commitment to build a new transmission line from Minnesota Power is part of the contract. The contract is signed. It's been approved by the regulator. There will be a 230 -- at least a 230 kV transmission line. The uncertainty that's associated with the line is whether the line gets sized lar -- to be larger than that.

And -- and then as it says here, the contract requires Minnesota Power to build new transmission. And -- and that was an essential part of the transaction, both from Manitoba Hydro's perspective and from their perspective, because they're -- they were looking for an investment opportunity in transmission.

So, you know, the -- the challenge that we have is not just to sell power in the export market. The challenge we have with companies like Xcel, and Minnesota Power, and Wisconsin Public Service is for them to start thinking not just five (5) years out and putting in the next combustion turbine, but start thinking out twenty (20) years, thirty (30) years, because that's the kind of time frame that Manitoba Hydro requires, because our build times are -- you know, are so long. So when we say, You know what, we want you to sign today, and it's 2010, or 2011, we're not going to start delivering until 2020, and the power sale will continue to 2035. They're tal -- now we're talking about time horizons that they never -- they were never faced with before. They -- they need a combustion turbine three (3) years from now, they can put it in.

So we have to get them to start thinking. If they want to have a diversified portfolio that includes hydro, to start doing coordinated generation planning. And that's what we've been successful with, with Minnesota Power and Wisconsin Public Service. And -- and it's not -- it -- it -- and -- and -- so there's a bunch of constraints they have. We have a bunch of constraints. And it's how the companies can work together to -- to optimize the entire package for both -- both sides.

DR. PETER MILLER: Do either of these require Keeyask rather than wind or something?

MR. DAVID CORMIE: The -- the sale agreement with Minnesota Power is subject to Manitoba Hydro committing to building a Keeyask, Bipole 3, and a major new transmission. If for any reason we chose not to build Keeyask, we -- we didn't build Bipole 3, or we could build a -- a US interconnection, the transaction falls off the table in 2016.

So there -- there -- Manitoba Hydro holds a condition precedent that allows us to walk away from the transaction if for whatever reason we choose not to build either any of those three (3) projects.

Now -- and you -- and you can understand, given Minnesota Power's alternatives are short lead-time alternatives, if we went to them in 2016 and said, You know, we couldn't get it through the regulatory process; we couldn't get Keeyask built; for some reason the Bipole couldn't be built, or we couldn't get the new inter -- international transmission line built, they would say, Okay, we have another alternative. We can build a -- we can build a -- a combustion turbine, or build wind, or -- or they'll do something different.

So the -- the agreements are all structured to give Manitoba Hydro the say on whether the generating station is built. These agreements don't require Manitoba Hydro to build anything. But if we choose to build it, these agreements will -- will proceed.

DR. PETER MILLER: And another question: Is the -- are there any provisions for renewing these contracts beyond those time frames?

MR. DAVID CORMIE: No. No, those contracts expire on those dates. The other transaction with Wisconsin Public Service...

Yes?

MS. MARILYN KAPITANY: Sorry, just before you leave that, did you say that the Canada/US transmission line was going to be the responsibility of Minnesota Power, so they would build and pay for that--

MR. DAVID CORMIE: They will build -- they will build, at a minimum, a line from the border to Duluth.

MS. MARILYN KAPITANY: To Duluth, okay.

MR. DAVID CORMIE: Right. And Manitoba Hydro will built the transmission line from Winnipeg to the border.

MS. MARILYN KAPITANY: Okay.

MR. DAVID CORMIE: And we'll pay for that. The -- the -- there is an option that we're all exploring, is to build a bigger line than is necessary for that sale. For -- for a 250 megawatt sale you only have to build a 230,000 volt line. We've identified that building a 500 kV line, twice the voltage, had more time -- four (4) times the energy carrying capacity than a smaller line. And that -- and if you're going to build Conawapa, you need to have a big -- a -- a big transmission line.

MS. MARILYN KAPITANY: And so who would pay for that transmission line?

MR. DAVID CORMIE: Well, that -- that's --

MS. MARILYN KAPITANY: -- from the border to Duluth?

MR. DAVID CORMIE: From the border? We're -- we're negotiating that right now. There -- it's -- there -- if it were to be built, Manitoba Hydro will have to put up some of the money until the point in time where there are enough sales in the United States to use that extra transmission service.

The -- the initial sale with the Wisconsin Public Service is for a hundred megawatts. And it goes -- the -- the agreement goes from 2021 to 2029, although energy deliveries under it go from 2021 to 2027. So there's -- but the -- but the transaction goes on for an additional two (2) years for transmission reasons.

But Manitoba Hydro already -- and -- and Wisconsin Public already own network service from the border to -- to -- and so we're utilizing that existing trans -- transmission service, firm service, to make this transaction. And so we're -- we're still in the process of -- of dis -- of -- of negotiating with Wisconsin Public Service on any additional sales above the hundred megawatts that would come off of Conawapa. And that --

MS. MARILYN KAPITANY: Okay.

MR. DAVID CORMIE: The -- the critical aspect in -- in those discussions are what is the cost of additional transmission above the cost that Minnesota Power is willing to invest, so taking the line from 250 megawatts to -- to 750 megawatts. And --

MS. NICOLE FITKOWSKI: Da -- Dave, I have --

MR. DAVID CORMIE: Yes.

MS. NICOLE FITKOWSKI: -- Dave Lamont, who has a question for you.

MR. DAVID LAMONT (VIA CHAT): Do the price terms of the contract reflect market clearing prices in some manner?

MR. DAVID CORMIE: The -- these transactions provide that there will be transmission service provided in the US by these companies and to the extent that that transmission service is not necessary to serve the sale. So you've got a sale that goes for sixteen (16) hours a day. Well, what about at night, the extra -- the next eight (8) hours?

These companies are required to make that transmission service available so Manitoba Hydro can sell energy on that transmission and they will buy it. So we have the right to sell energy on that transmission, and they are obligated to buy it. But it's at market price, and it will be sold back into the market.

So, in effect, we're getting to use the transmission service that these companies are putting in place to facilitate market transactions when we have surplus energy. So we have the right to use it if we want to. If we don't have -- if -- if we don't need it, we don't have to use -- we don't have to put energy on it. But those -- those surplus -- or those additional energy transactions are an option for us.

So there is -- there are times when -- when we have the right to take energy to market on firm transmission and get market price for it. Okay, I'm probably running short of time.

Why do we have export contracts? Well, we need to define in legal terms the product, the quantity, the price, and the term.

(MOVED TO SLIDE 4)

MR. DAVID CORMIE: What is the power? Well, it's system participation power. And generally, on the quantity, it's so many megawatts for so many years. And it starts at one (1) hour in the mor -- in the day and it ends at another hour in the day. It defines what the price is and what the term is.

And these transactions start out generally with an MOU, where you agree to discuss the possibility. And generally, an MOU just puts terms and conditions around issues like confidentiality, We're going to talk about this transaction and -- and we're -- and we're going to respect each other's need for -- for confidentiality.

And that generally leads to a term sheet where you've agreed to the major terms and conditions, like price, duration, how many megawatts it is. And then finally, we'll then -- after you've signed the term sheet, at some point later, you'll end up at the very formal power purchase agreement that's subject to -- to approval.

The -- it sets out all the terms and conditions of the -- the contract sets out all the terms and conditions. And, you know, these things --

you know, when I started, you could have a con -- a long-term contract that might only be five (5) pages. These things now go on for hundreds of pages, and they -- they define all the terms and conditions, the transmission arrangements.

Remember, we talked about how transmission service -- and what do you do, who's going to provide service, what happens if that service is interrupted, all the scheduling and curtailment rights, when are you going to order your power. You have the right to curtail. Under what cu -- circumstances can you curtain. All the issues about billing and payment and what currency are you going to pay your bill in. And how do you maintain creditworthiness, dispute mechanisms, defaults, issues of bankruptcy, issues of confidentiality, and conditions, precedents, and approvals.

And -- and Byron was talking about that su -- subject to Conawapa -- well, or TS. Well, we have conditions precedent in there that says, This transaction's not going to go anywhere if we don't build Keeyask; it'll just stop. So it's a condition precedent.

Another condition precedent, or approval, is it's subject to regulatory approval in

Canada, both by, you know, the National Energy Board, or -- and in the United States, they -- they have to get regulatory approval in Minnesota. Things like, we need an order in council in Manitoba to get the contract approved.

And so all those condition precedents are laid out in the agreement. And then there's just pages and pages of general terms, general commercial terms, associated with a -- a good contract.

(MOVED TO SLIDE 5)

MR. DAVID CORMIE: The supply and -- and purchase obligations deal with the issue of capacity. How much capacity are you going to supply? And in the case of the Minnesota Power transaction, it's 250 megawatts. But there are no reserves. Generally, that's the difference between a firm power product and a system participation product. Firm means that if something goes wrong, you have some reserves here to help out in that -- in that contingency.

And for all of us, as customers in Manitoba, we buy firm power. And so if something goes wrong in the power system, the lights don't go out because Manitoba Hydro has reserved -- has held reserves. In -- in these sale agreements, these are system participation. The buyer is participating in the risks of the power system, so if something goes wrong, the sale gets cut. They're exposed to our -- you know, if a -- if lightning strikes something, and -- and blows up, we have the right to curtail.

So it -- it defines the -- our capacity obligation, it defines how many megawatt hours we're going to deliver, and it -- and it talks about the quality of supply. And we have to have an independent third-party accreditation process to say that these megawatts really are deliverable. You're not buying a pig in a poke. There's -- there's an accreditation process.

And it defines the delivery point. Where is the electricity actually going to get delivered to? And generally that's the point where the transmission line crosses the border.

And then it talks about the environmental attributes. And that's really important now, because our customers want the electricity, but they also want to be able to say that it's coming from a non-emitting resource. And so we talk about where's the source of the power? How are we going to track the environmental attributes? And -- and how are we going to transfer those attributes to you?

Traditionally, electrons were just electrons, but now they're pai -- they've been painted. Some of them are green, and some of them are blue, and some of them are brown. They want to know, What are we getting? And, in the Minnesota Power case they want hydro. They want large hydro attributes, and -- and we have to be able to provide those. And if you don't have them then what do you do? How can -- do you have the right to substitute? Yes?

MR. BRUCE DUGGAN: It sounds like we have some outs. Right now, they're under a mandate, or they have a goal of 50 percent renewables.

Do they have outs if a different government comes in and says, You know what, let's not do that; let's just do natural gas?

MR. DAVID CORMIE: No. Under none of the contracts do the customers have cancellation rights. They're all -- they're -- from our perspective, they're take or pay.

(MOVED TO SLIDE 6)

MR. DAVID CORMIE: The -- the contract has -- talks about pricing, it talks about -- Joanne talked about, this morning, about the difference between the price for energy and capacity, so we sell -- we -- we have a price on the capacity. And that's in terms of dollars per megawatt month.

Let's say it's six thousand dollars ($6,000) a megawatt month. They buy 500 megawatts, so six hundred (600) times five hundred (500). There's three hundred thousand dollars ($300,000) a month in demand charges. That money comes to Manitoba Hydro every month regardless of whether we make delivery of any energy at all.

And then there's the price for the electricity. If they're buying fixed-price energy, they'll -- there's a formula in the -- in the contract that lays out what that price will be. They pay that, and then if there's any additional energy at market price, then they'll pay for that market-priced energy. And so the pricing terms define out -- define how those prices are -- are calculated.

The prices are all in -- for the fixed-price energy, the -- they're all escalate, so they -- they keep track of in -- they -- they keep up with inflation, and they may be either a fixed escalator. They might be just, you know, 2 percent a year, and it goes 2 percent a year for twenty-five (25) years. Or, it may be tied to an index like the CPI, or the US GDP deflator, something that reflects the increasing value of electricity over time.

(MOVED TO SLIDE 7)

MR. DAVID CORMIE: Scheduling and delivery involves the issue of transmission service. And we talked about that this morning. How many megawatts of transmission service are you reserving?

They want to be assured that Manitoba Hydro has got the transmission in our -- in our area to make sure that our product can be delivered. We want to be assured that they've got the transmission service in their jurisdiction, and who pays for that transmission service.

It talks about changed circumstances and, you know, Joanne talked about the MISO market and how it's become -- you know, how electricity -- but what happens if MISO in five (5) years goes away? We have to have arrangements in the contract that says, If Miso goes away then how are we going to fulfill our obligations to each other under the contract? So, we -- we map out: Oh, well, we're going to sell to you at the boarder. You're going to buy from us. You'll arrange for transmission service.

And we pretend that -- that the MISO has disappeared so that the contract can -- can continue, and we've thought through all the issues and the risks of -- of changing circumstances. Because we're talking about contracts now that -- we're going to go to 2035/2040. That's a long time to think that the world is going to stay the same. In the time that I've been doing this, we've gone through three (3) market revolutions, and I don't think in five (5) years it's going to be the same. It'll be different. And so when we're negotiating these things we think those things through, about the default provisions.

What's really of significance to us is the curtailment rights that we have under the contracts. Manitoba load always has priority, so if we get to the situation where we're selling electricity to our customer and continuing to sell that electricity to -- to the customer puts the Manitoba load at risk because now we have insufficient energy or capacity to serve our loads, Manitoba Hydro has the right to curtail delivery under these contracts. And those can be triggered by either generation or transmission events.

So imagine that there's -- we're

delivering 500 megawatts to NSP, and we have a fire at one of our generating stations, and now we've lost a thousand megawatt generating station due to a fire. That's a generation curtailment event. And in that circumstance, having lost that thousand megawatt generating station, the question is: Whose load doesn't get served? So the contract allows us to cut the export sale first so that the thousand mega -- the -- anything that's left in the power system is available to serve Manitoba load.

So it divines those events. These are the events for which curtailment can occur: fires, explosions, loss of transmission service, tornados, hurricanes, forecasting error, you name it. At any point in time if one of these events occurs, a force majeure, we hae the right to curtail.

And then the last thing is curtailment priority. Well, then you've got all these contracts. Which one of us who has a contract with Manitoba Hydro gets curtailed first? Where do I land in the pecking order? And so that -- there's a priority criteria.

So the -- the contracts talk about tho -- those issues.

(MOVED TO SLIDE 8)

MR. BYRON WILLIAMS: Dave?

MR. DAVID CORMIE: Yes, Byron?

MR. BYRON WILLIAMS: Byron Williams. Just going back to the pricing slide. You -- you don't have to turn there, but in terms of the escalation and the index, is it -- presumably it's conceivable it could be indexed to the price of natural gas, or some sort of relationship with it?

MR. DAVID CORMIE: It could be. And -- you know, it's always a challenge to deciding what -- what the escalator should be. And we don't necessarily know which escalator in the future will be the best indicator of the real value of power, but -- but -- so we try and have a basket of contracts with a bunch of different escalators so that -- so that we're not going to -- you know, if they're all tied to CPI maybe CPI isn't the right measure in twenty (20) years, or -- but -- so there's a deliberate attempt to diversify the escalator, so that we have a -- that we're -- from a risk management perspective we're not all tied to the same -- to the same escalator. But it could be CPI, the US GDP deflator, it could be gas, or it could be a mixture of all those. There -- it -- it could be a combination.

MR. BYRON WILLIAMS: When -- when we're

looking at the three (3) forward-looking contracts you've been discussing, is there a gas escalator in -- in -- amongst them?

MR. DAVID CORMIE: I am not sure I can answer that question, Byron.

So the MP sale agreement. We've talked about this. It's 250 megawatts capacity in energy, deliveries seven (7) days a week sixteen (16) hours a day, and it obligates Minnesota Power to build a new transmission line.

In addition to that, there's a second agreement; it's an energy exchange agreement. And one (1) of the -- one (1) of the things that Manitoba Hydro wants is the ability to use network service to bring energy north in drought conditions. And so we have the right to purchase up to 250,000 gigawatt hours annually.

And -- and what that does is that -- that is enough of a commitment from Manitoba Hydro to purchase that we can reserve 250 megawatts of northbound transmission service to serve Manitoba.

So the 250,000 megawatt hours a year is -- is small relative to the volumes that we normally purchase. So this is something that easy -- is easily achievable at very little cost. And -- but what it does is it gives us access to that -- to that US transmission, and because we don't pancake the tariff, because it's used to serve Manitoban load, we, in effect, get that service for free. But you have to designate a resource in the US, so that's what this part of the agreement does.

The second part of the agreement is -- deals with wind storage services. And Manitoba Hydro is committed to purchasing 250,000 gigawatt hours a year from Minnesota Power to help them justify the -- their investment in wind in -- in North Dakota.

And, again, because Minnesota Power has agreed to make the transmission system bigger, it makes Manitoba a better battery for the -- for the marketplace. We're allowing them to share in the value of -- of the battery that they've contributed through their -- through their investment in transmission through this -- through this arrangement.

(MOVED TO SLIDE 9)

MR. DAVID CORMIE: The -- it's a fifteen (15) year term starting in May of 2020, going to '35. Where as a minimum -- so under the lowest flow years we're obligated to send them 14,060 gigawatt hours a year, which is delivery sixteen (16) hours a day, five (5) days a week.

But in -- in average years it'll be more than that, because they'll take energy sixteen (16) hours a day, seven (7) days a week. And -- and in a high water year when water supply is so great that we can load up that 250 megawatt transmission reservation twenty-four (24) hours a day for all hours of the year, it'll be 2,100 gigawatt hours that they're obligated to buy from us.

So it's about, between 36 and 50 percent of the output of Keeyask. So that's what MP's commitment is from us.

Pricing is -- includes both an energy price; it's fixed. And there's a -- and there's also a -- a market price formula, and there's also a capacity price. And there's a provision for escalation and overtime between now and when the contract starts, and then a slightly different provision after that.

(MOVED TO SLIDE 10)

MR. DAVID CORMIE: So under normal water conditions those are the -- we talked about those -- overnight deliveries are our option, and there's no transmission use costs to Manitoba Hydro. And adverse water conditions, if we need to, we can call back the weekend energy.

And there's this issue of curtailment. In a force majeure, whether it's flood, drought, you name it, we can curtail the sale to zero if necessary.

And that includes a drought of worse than record. So Joanne talked about this morning about designing the power system to be able to deliver firm power under that one (1) low flow year in the historic record. So if something worse than that -- so if -- if we had a year that was, you know, 80 percent of the worst on record, this tri -- this -- we -- we have no obligation at all under those circumstances to deliver any energy. We can -- we can -- all the capacity that they've bought out of Keeyask is -- is reserved under those circumstances to serve Manitoba load.

(MOVED TO SLIDE 11)

MR. DAVID CORMIE: So they're committed to building, at a minimum, of a 230 kV line, and that line needs to be in service for June of 2020. They have been championing on -- at the request of Manitoba Hydro a larger line. Our studies indicate that having a larger line is an economic alternative for Manitoba Hydro.

And so we've been going through the regulatory process in Minnesota with Minnesota Power on the assumption that it will be a five hundred (500) line. And they've gone and -- and undertoo -- undertaken public consultations, all their filings with the regulator have been based on a 500 kV of -- but that is not a done deal, and the option there is that it will revert back to a -- to a two-thirty (230) line if -- if we can't make the case for the five hundred (500) line work.

We're responsible for all the costs in the -- in Canada for the new transmission line, and they will be responsible for their costs on the US for the two-thirty (230). To the extent that there are additional costs above the two-thirty (230) line associated with the 500 kV, they may or may not be involved in those costs depending on the results of our -- our negotiations that are ongoing.

(MOVED TO SLIDE 12)

MR. DAVID CORMIE: There's some conditions and options. There is no requirement to build. This is -- addresses the question that -- our -- our obligation to deliver the power kicks in when Manitoba Hydro places the first rock in the cofferdam in -- at -- at Keeyask. Up to that point the -- Manitoba Hydro or the province can decide that Keeyask is not required, is not necessary, it's -- or it -- it can't be done. And -- and if that were the -- that -- that were the case, the contract would just terminate.

So there's -- there is some optional delays negotiated in there. We -- we're -- we've -- we negotiated such that we have a two (2) year delay option if necessary and -- associated with the start of the Keeyask. So let's say that we do agree that -- and we get regulatory approval to build Keeyask, but it's going to be a year late or two (2) years late. The contract provides for up to a two (2) year delay or a delay in the start of the -- of the transmission facilities.

So we need to have Bipole 3 in service in order to make deliveries. So if there was some reason Bipole 3 were delayed, even though the generating station may be on track, we can't get the power out of the North, then that would be a reason to curtail deliveries for two (2) years. And then it says here that the -- the term -- the agreement terminates the penalty if -- if ni -- either condition is not satisfied by June the 1st, 2016.

Peter...?

DR. PETER MILLER: Yes, I'm trying to put together a couple of responses. You have these outs if you don't build Keeyask and so on. And in response to Bruce, you said, They don't have any outs. If you wanted to supply them with natural gas, they'd still have to take natural gas.

Did I understand that correct?

MR. DAVID CORMIE: I didn't say anything about natural gas.

DR. PETER MILLER: Okay.

MR. DAVID CORMIE: I'm saying they have an alternative of -- of building their own facility rather than buying from Manitoba Hydro. So these condition precedents that protect Manitoba Hydro have been timed so that they still have the alternative option of building a generating station in Minnesota to serve their load.

DR. PETER MILLER: Okay. But my question is: If you could find a way to supply them with wind instead of Keeyask, can they say, No, we want Keeyask? Do -- do they have control over you building Keeyask if they are to be a party to the contract?

MR. DAVID CORMIE: The simple answer is they're not interested in wind. They have more wind than they know what to do with under their mandate in Minnesota. They don't want more wind because it has no -- it doesn't have the dispatch ability and it doesn't have the capacity.

DR. PETER MILLER: Well, the combination. I mean --

MR. DAVID CORMIE: Yeah.

DR. PETER MILLER: -- suppose you -- you backed wind and so on.

MR. DAVID CORMIE: So you -- you have to remember what they're doing here, Peter. Like Xcel, they -- they now have a capacity resource, and -- and they can -- they can help use their wind resources to meet -- to meet their load.

But -- but really, they're not interested in anything but a hydro product, because Manitoba wind has no advantage to them except -- and -- and it has a huge disadvantage because it's not subsidized the way that US wind is. In the United States, they get a production tax credit. You can buy a contract from a wind farm in Minne -- in -- in North Dakota for under thirty dollars ($30) a megawatt hour because of a subsidy. There's no way that you can buy that in Canada.

So we would be investing, you know, twice as much to get the wind resource built to sell to them when they already have an economic alternative that's half the price. So they're -- they're not interested in buying wind.

DR. PETER MILLER: DSM --

MR. DAVID CORMIE: Well, yeah, okay, but...

Okay, so -- so they -- they have alternatives that -- wind alternatives that are way less expensive than -- than Manitoba because they have the ta -- production tax credit available to them.

They -- this contract is tied to the construction of new hydro resources in Manitoba because what they want is they want to have a diversified portfolio that includes wind, hydro, some other renewables, gas, and coal. And -- and so hydro is a -- is -- you know, is one (1) of the legs of that four (4) legged stool.

(MOVED TO SLIDE 13)

MR. DAVID CORMIE: Other provisions; it's served from the Manitoba Hydro generating system, so participation -- they're participating in the entire system. So although we need to -- we would need to build Keeyask, the power is not coming from Keeyask. It's coming from the surplus that's available from all the generating stations in the system.

But they are exposed to all our generation and transmission risks. There are participating not only in the energy, but in the risks of -- of delivering that energy. And as I said before, Hydro -- Manitoba's native load has first priority to the energy.

And there are no liquidated out -- no liquidated damages in the contract. Liquidated damages would be, Oh, we're -- we can't deliver to you because we've had an outage. Liquidated damages would require us to go to market, buy market price power, and sent it to them. There is nothing in the contract that requires us to -- to pay liquidated damages, although the contract gives us the right to go to the market and buy energy to deliver it if our system is not capable of doing it.

Say, for example, that Minnesota Power is buying the energy at eighty dollars ($80). Market price is at twenty dollars ($20). We have a curtailment. Why wouldn't we just buy twenty dollar

($20) power, deliver our -- deliver it to them, and get eighty dollars ($80) for it?

So the contract allows for us to purchase electricity to serve the sale even though we have -- have been subject to a curtailment that gave us the right to curtail.

(MOVED TO SLIDE 14)

MR. DAVID CORMIE: And there's -- there's a bunch of approvals required. Manitoba Hydro Board approval, that's happened. The -- we've got the order in council from the province. The National Energy Board of Canada, we have yet to get the export permit for -- for that line. Is that correct, Marla, do you know? I can't remember if we -- we got the permit yet for that.

And we -- we do not have the international power line export permit yet. That will still come. Minnesota Power needs -- needed their board approval. They've got that. The Minnesota Public Utility Commission has approved the transaction, and the Midwest ISO has approved the capacity as a capacity resource.

So I think the only outstanding items

left are NEB approval in Canada for the sale and for the construction of the new line.

So those fundamentals about that contract apply to -- to the other contracts. They -- they may be different pricing amounts. The formulas may be sightly different. But there's nothing sign -- not really significant -- there's nothing significantly different between the -- the sale to WPS, MP, and -- and to Xcel. Okay.

Are there any other questions?

(BRIEF PAUSE)

PRESENTATION RE: REVIEW OF MANITOBA HYDRO SUPPLY AND DEMAND TABLES:

MS. JOANNE FLYNN: Okay. Good afternoon. I'm going to do the presentation on the review of the supply and demand tables. And what you're having handed out to you, or have available to you, is a set of documents that consists of firstly a -- a Word-type document that has got, "Manitoba Hydro dependable energy supply and demand tables," on the top of it. And that is what I would call a guidance document to explain the setup of the supply/demand tables.

And today I'll go over the dependable energy one. So accompanying that guidance document are the actual supply/demand tables, or an illustration of the supply/demand tables, that you will see in the NFAT submission. And there's three (3) separate tables, and they are printed front to back. So you'll see it starts with the year 2012/'13 or the year 2013/'14, depending on which set of tables you're looking at.

So what I would call the first set of tables will say, "NFAT 2012 reference, no new resources." The second set will be "May 20" -- sorry, "NFAT 2012 reference preferred development plan," and the third set of tables is the, "NFAT 2013 update preferred development plan."

And we'll refer to those as -- as I go through the presentation but I have just a couple of introductory slides before we get into -- into the details.

(MOVED TO SLIDE 2)

MS. JOANNE FLYNN: So I went through this morning the generation planning criteria, and I've brought it back up here because it is the generation planning criteria on which our planning is based. So just as a reminder, it's -- it's that 12 percent reserve on the capacity side, and it's planning the system around the lowest coincident water con -- supply conditions being repeated.

(MOVED TO SLIDE 3)

So when we look at these supply/demand tables -- oh, sorry. And I was also just going to remind you about the definition of 'capacity' and 'energy'. So capacity being that rate of output, and -- and Dave's elevator example of how much you can -- how many people you can stuff into an elevator. And then the energy produced, be -- in gigawatt hours is what you're going to see. So if you're looking at the top of these tables, you'll see that it says it's in gigawatt hours. These three (3) tables are in gigawatt hours.

(MOVED TO SLIDE 4)

MS. JOANNE FLYNN: Okay. So the supply/demand tables are confirming that we have met the generation planning criteria. So they provide dates for the new resources when we look at no do --

the -- the purpose of the no-new-generation table is to show when we become short of resources. And the one (1) you're looking at is the energy, dependable energy table. It also -- it also shows how much exportable surplus we have in the system.

And it provides our system modelling with -- with a ma -- very major input for doing -- for doing the modelling and the evaluation work that we do. So the capacity criterion is the application of the 12 percent reserve. And for both the capacity and energy, what we're going to do is create development plans that ensure we have no capacity dev -- defit -- deficits over the thirty-five (35) year planning horizon, nor do we have any dependable energy deficits over that thirty-five (35) year planning horizon.

(MOVED TO SLIDE 5)

MS. JOANNE FLYNN: So, once again, I think I've showed you this before. Let me just get it up here. So what you're going to see on the supply/demand tables -- this is the same slide I used earlier -- is you're going to see -- see the quantities associated with the hydro resource, the thermal resources, wind, and the pur -- any purchased energy that we have in the development plans. So firstly we would start out with the system as it exists with no new generation being added to see when those deficits will occur.

(MOVED TO SLIDE 6)

MS. JOANNE FLYNN: Okay. So on the -- on this next slide, which is labelled as "NFAT 2012 Reference" -- and I've just taken selected years out of the table that you have in front of you to -- to show you when we need new resources. Now, you have the dependable energy tables in front of you. I've also put the capacity one up on the -- up on the slide here.

But just to keep things sort of manageable, we're only going to go through the dependable energy tables. So you don't have a copy of the capacity tables. But just to show you that it is the dependable energy that is the trigger for new generation, and -- or new resources, because -- now this is according to 2012 planning assumptions. In the year '22/'23 is when you see the red numbers starting to show up. So that's when the deficits start persistently showing up.

So what we're doing is we're saying --

and I've just taken sort of the su -- the totals for supply and demand to show you this calculation. So total power resources, total energy demand, and you subtract those two (2), and you get your system surplus or deficit. And then there are a couple of conditions that, where we can't export everything that is surplus, you take those off and you get your exportable surplus. But the point of this chart is to show you when we need new resources.

If you look at the capacity table, it is structured similarly, so you've got total power resources, total peak demand, subtract those two (2), and you -- you see when the system starts being short of capacity. And based on the 2012 assumptions, it's in '25/'26.

(MOVED TO SLIDE 7)

MS. JOANNE FLYNN: I've also done this for the 2013 information, so the -- the planning assumptions around supply and demand for 2013. So the same process of looking at total power resources, looking at the total energy demand, and then subtracting those two (2).

And with the change -- slight changes in some of the supply side and a drop in the load forecast for 2013, we see that we need new resources from a dependable energy perspective in the year '23/'24.

And from the capacity side, again it's -- it's also shifted a year with the 2013 assumptions so that new capacity resources would be required in '26/'27.

MR. BYRON WILLIAMS: Hi, it's Byron. Looking to the NFAT 2013 update and on the energy side for 2025/'26, I guess it's in a surplus because the -- you've amended your -- your net load by a fair bit and then a modest change in your total power resources?

MS. JOANNE FLYNN: Yes.

MR. BYRON WILLIAMS: And does that beg the question of -- of whether we can just bridge out to 2025/'26 rather than building for those earlier years?

MS. JOANNE FLYNN: It -- it would if it were -- if the deficits were small. But the deficits at 592 gigawatt hours is too substantial to try and bridge through that. So that would result in us building for the '23/'24 year.

Barb...?

MR. BRUCE DUGGAN: I'm just wondering if -- if you could tell us what the -- the calculation is for the price elas -- or the demand elasticity based on price of the electricity, of domestic demand for electricity? The -- to make a projection that you need more is based on an assumption that demand will be more.

MS. JOANNE FLYNN: Correct.

MR. BRUCE DUGGAN: But the demand is affected by price. So --

MS. JOANNE FLYNN: The --

MR. BRUCE DUGGAN: -- I'm wondering if you could tell us what your projections for price are and what -- and, more importantly, what your calculation for the elasticity of demand based on price is.

MS. JOANNE FLYNN: So -- so you're asking me load forecasting questions, which is the -- the -- which is the presentation after this.

MR. BRUCE DUGGAN: Sorry.

MR. BYRON WILLIAMS: Sorry, Joanne, and --

MS. JOANNE FLYNN: Yeah.

MR. BYRON WILLIAMS: -- and then I'll shut up. But the -- what would -- if -- if five hundred (500) is too much, like what's that threshold of being an acceptable or -- in terms of deferring generation?

MS. JOANNE FLYNN: Well, if we were to stick exactly to the planning criteria, 1 gigawatt hour would be too much. But there isn't really that level of accuracy in being able to forecast these quantities but it would have to be a smallish amount. And I would -- would say it would need to be less than 100 gigawatt hours.

(BRIEF PAUSE)

MR. SVEN HOMBACH: Hi. It's Sven Hombach. Just looking at the NFAT 2012 reference table and then the update, starting in 2025/'26 there's a change in the total net export assumption from about 188 gigawatt hours per year to three hundred and fifty (350), and then carrying forward.

What's the basis of that change in assumptions?

MS. JOANNE FLYNN: Which tables are you looking at?

MR. SVEN HOMBACH: Starting at the NFAT 2012 reference table.

MS. JOANNE FLYNN: Which -- which 2012 reference table? On the slide?

MR. SVEN HOMBACH: Oh, it's on the

slide, yes.

MS. JOANNE FLYNN: Okay.

MR. SVEN HOMBACH: The -- line 9, the total net exports, 2025/'26 --

MS. JOANNE FLYNN: M-hm.

MR. SVEN HOMBACH: -- less 188 gigawatt hours, and the 2013 update more or less doubles that to about three hundred and fifty (350). And that seems to be carried forward to the next four (4) years.

MS. JOANNE FLYNN: Well, that -- that would be a change -- change in the export sale assumptions between 2012 and 2013.

MR. SVEN HOMBACH: And is that just based on market sales, or is that based on contracts?

MS. JOANNE FLYNN: Those are long-term sales only, long-term firm sales only. And we will -- as we go through the -- the categories of the tables, we'll -- we'll -- you'll see that a little more clearly.

(MOVED TO SLIDE 8)

MS. JOANNE FLYNN: Okay. Now -- oh, one (1) more question. Oops.

MS. NICOLE FITKOWSKI: Dave Lamont

says:

MR. DAVID LAMONT (VIA CHAT): Could the deficit be made up with a firm purchase contract?

MS. JOANNE FLYNN: Once again, where the -- where the deficits are smaller, we do -- we do assume that we can cover them with -- with purchases. But in this case, two (2) years in a row and the size of the second year would not be something that we would be willing to enter into.

Okay, this -- this slide on generation supply sources over a range of water conditions, the -- the tables that you're looking at are dependable energy tables. So in every single year of the table, we are in dependable conditions.

So what I'm showing you on this chart is the range of water conditions, and they're ranked in historical order from the lowest to the highest. So basically, every year on the chart is representative of the very leftmost position for water conditions, the lowest on record.

But in even -- any given year, we can have water conditions that will range -- well, we don't know actually what they're going to be. But from a planning perspective, they can be from the lowest on record to the highest on record.

So in any give year, we can supply the load from this mix of resources, which include wind, thermal, and imports along with the hydro. And I've -- we've layered in the DSM at the very bottom. It's actually, in terms of this chart, really small on the bottom of the chart.

So -- and wind is a fairly constant amount. We're assuming that -- that 85 percent of average annual production is what we can rely on for the wind resource, and it is always there.

So the hydro will range, as you see, with -- with the blue -- blue line or the blue part of the -- part of the graph. When we're in that lowest 10 percent of water flow conditions, we need to rely on thermal resources to supply Manitoba load. And you see the total commitments above that.

When we get to those types of conditions -- we've shown thermal and imports on the graph. And basically, at the time of the -- at which we're operating, so in the operating time horizon the decision will be made as to what is the most cost-effective way of supplying the -- supplying the load, either from our own thermal resources or from imports.

As David mentioned earlier, we have some very expensive thermal resources on our system, so very often it will be more economic to serve it through imports. It also shows you that, over time, there is still value in importing from the market even though we have enough hydro to serve our load, and that would be the opportunity to buy in the off peak and resell in the on peak.

So this is the depiction of what could happen over the whole range of water conditions. But what the tables are representing is that meeting of our planning criteria if we were in the lowest water conditions on record.

(MOVED TO SLIDE 9)

MS. JOANNE FLYNN: Okay. So now, as far as the tables are concerned -- and what I've got up on the slide is -- is basically just the -- the title's on the left-hand side of the dependable energy table. And we prepare a set of supply/demand tables for each development plan. So you actually have an example of no new generation, so the existing system, and one (1) of the development plans, which is the preferred development plan. And then you have that plan represented for the 2012 assumptions and the 2013 assumptions.

So in terms of what con -- what the power resources consist of, we have it divided between new power resources and base supply power resources. So new power resources will be those that are required as new resources depending on which development plan it is. The base supply of resources are a set of resources that are common to all of the development plans.

So you will see that in the no new generation, the base supply of resources is -- is the supply that we're looking at. And if you look at your handout, the table, you will see that for the no new resources supply/demand table, it's blank all the way across for new resources. This is just there so we can identify when we need those resources.

So if you were to look instead at the 2012 reference for the preferred development plan, what you see is, you see energy values coming in for -- in 2019/'20 for the Keeyask generating station. And you see the dependable energy quantity coming in starting in '25/'26 for the Conawapa generating station.

And you see that in that first year, not all the units are in service. So there's a lower amount of dependable energy in that first -- first year when the units start coming in, until they're all in place. And they're all in place by the second year -- well, the third year for -- for Keeyask, and the second year by Cona -- for Conawapa.

Okay. So new -- new resources, depending on the plan, will either be hydro, thermal -- and, actually, if you flip your page over to the -- to the back of it, you start seeing in 2041/'42, under the preferred development plan, new simple cycle gas turbines coming in in that year. And that would be to finish off the thirty-five (35) year planning horizon.

We look at what the least capital cost resource is to put in place at that time, and put it in there almost effectively as a placeholder because we're not really planning out in detail to -- to that length of time. So that gives you your total new thermal.

And then new imports, whether they're contracted or proposed, so there's either a -- a contract in place, or proposals through a term sheet or other means. And those will be added, so you should see with the preferred development plan that you see some proposed and contracted imports coming in at that time. And the imports are not done in isolation, typically. They're going to be associated with an export sale as well.

So for the purposes of us identifying

our sources of supply, as opposed to the demand placed on our system, it's separated into what we can count on for imports, and what our obligation is to export. Okay. So also on this plan, you won't see new wind coming in. But in the development plan for wind you will see new wind coming in on the line that's in place to -- to show new resources related to wind.

The base supply of power resources, first of all, the existing hydro. And you will notice that the existing hydro, if you look out over time, very slowly is declining. And this is a result of what -- what Dave was talking about this morning in terms of the watershed, and what we can count on for new resources, and that there are withdrawals in the system before it gets to Manitoba and there's a recognition that -- or an expectation that, over time, it will slowly decline. So from a -- in terms of what we can rely on to serve Manitoba load, we want to be sure we have accounted for that.

The existing thermal plants. Brandon coal unit 5. You'll see that it's there until -- should be '19/'20 -- 2019/'20. And after that the -- the row is blank. That is when we intend to stop relying on the Brandon coal unit. And that is tied to the federal regulation for coal, in terms of determining probably the -- the most reasonable retirement date for that -- for that unit.

And the Selkirk and Brandon gas units will continue through to the end of the planning horizon. There is the expectation -- oh, yeah, question?

MS. NICOLE FITKOWSKI: Bill Harper asked:

MR. BILL HARPER (VIA CHAT): How does DSM fit in? Is it considered a resource, or factored into the load forecast?

MS. JOANNE FLYNN: Okay. It -- it would -- on the supply/demand table it's being shown as a reduction of load. And -- I mean his -- historically if you look back on our plans we have shown it as a resource. In effect when it -- in terms of the supply/demand table it has the same impact of reducing the -- the surplus available.

So in the -- in the NFAT submission and in the charts you're seeing today it's being reflected as -- as a reduction to our requirement to meet overall demand, and it'll be shown on that portion of the table. And it will be coming up probably on the next slide when I get into the demand side of things.

So in terms of the base supply of power

resources, again there is -- there is contracted imports and proposed imports that are common to all the plans and so they are shown here as -- as a base supply. We also have market purchases which is that part of the planning criteria which says that we can purchase from an organized market and rely on those purchases out in the future.

The hydro adjustment is also actually rela -- related to a particular type of export sale, and that's the diversity sales. And basically that is because the diversity means that we have an obligation in the summer months to -- Dave talked about NSP and -- for example, and they have an obligation to us in the winter months.

And allowing us to purchase power in the winter means that we don't have to run our own generators as much, and because of our climate there are icing restrictions in the winter. So it is more efficient for us to use our -- our generators in the summer than in the winter. And that amount can be calculated, that -- that improved efficiency, by having the amount of diversity contracts we do can be calculated and it's represented on -- on the table as a Hydro adjustment.

So existing wind. You will see an

amount of some 777 gigawatt hours on the table for the existing wind contracts. This is -- this is from an energy perspective. We count on them for dependable energy.

And then two (2) other items that are common to all plans. One (1) is -- I will call it a placeholder for the Pointe du Bois rebuild out in 2030/'31. That does not mean there's any commitment to do this but it is common to all plans so it does not effect the -- the evaluation of -- of any particular development plan.

The Bipole 3 line reduction is -- actually it should probably have the word 'loss' in there. And what that is, is by putting in a third Bipole the line losses can be reduced a noticeable amount when the loading is spread across three (3) Bipoles rather than two (2). So from the time it's in service until -- with -- with Conawapa coming on the savings becomes reduced as the line loading increases.

But because that isn't -- and there isn't any other northern generation being added besides Keeyask and Conawapa in these plans, you'll see it be reduced with Conawapa coming on and hold at that level for the rest of the planning horizon. And that's -- so that takes us to the total of the power resources.

MR. ED WOJCZYNSKI: Just a comment. You -- you mentioned the import, and the -- the energy import. There was that question earlier about counting on energy imports to get through a short-term deficit and you talked about the hundred gigawatt hours.

It might be, I think, useful to point out that we're already counting on, in the off peak, fully loading up the off peak with energy imports in that drought year. So in the scenario where we show a deficit we already are very heavily loaded up with dependable energy imports in -- in the off peak, fully loading up the off-peak portion of the tie-line, so up -- up to the 10 percent criteria for -- of our load. So that -- that's -- it's not just that we -- that's part of the -- the background to the judgment call is to -- how much additional can we count on if it's just one (1) or two (2) years of deficit?

MS. JOANNE FLYNN: Yeah.

MR. REGIS GOSSELIN: You mentioned the -- the reason why we would be importing energy from the US in -- in terms of the saving our generation capability and -- and so on. I'm wondering what's going on with respect to an increase in proposed imports around about '14/'15 under the new -- no new -- no new resources, or any of the other scenarios as well.

What's -- what's going on there that you would need to be increasing imports?

MS. JOANNE FLYNN: The pro -- the proposed imports under the no new resources? Are you talking about under base supply power resources?

MR. REGIS GOSSELIN: I'm looking at the proposed imports line for the preferred development plan, but also the...

MS. JOANNE FLYNN: The ba -- the base supply line? Yeah. So the base supply line includes contracts that are common to all -- to all development plans. So what is going on there is there is a -- a renewal, if you like, of one (1) of the diversity contracts that is coming in in those years. So that's why it's -- it's carrying on and is -- is at that level. But it -- it doesn't show up under new proposed because it's common to all the development plans.

(MOVED TO SLIDE 10)

MS. JOANNE FLYNN: Okay. From the load and export commitment side of things. And what I've got on the slide is looking at the -- the 2012 -- one (1) of the 2012 supply demand tables. So first of all, Manitoba domestic load is based on, in this case, the 2012 base load forecast, which -- which means it's -- it's based on -- so that 50th percentile type of -- of load.

There's also a very small amount -- if you look at -- at the table itself you'll see it's in the order of -- well, no more than 100 gigawatt hours, but starting at 10, 25, 30 gigawatt hours for construction power for new hydro. So it's noticeable enough that we make sure we -- we show it separately. And, of course, depending on the development plan, it will be there or not be there.

And then from -- in that -- in that sub -- sub-total will also be the amount for -- of the DSM forecast. So that's how DSM is reflected in the supply demand tables as a reduction of overall requirement to serve Manitoba load. So we've called that Manitoba net load.

From that -- or -- of the next category is really the exports. So either the contracted exports that exist, or proposed exports. And there are some contracts that contain what's called an 'adverse water clause'. And that is where we are in low water conditions. And Dave was talking about this as part of the contract terms, that we do not have to deliver the energy.

So one (1) of the examples would be for the MP contract where it's a seven (7) by (16) product if we have the water. So that's seven (7) days a week, sixteen (16) hours a day. If we say that we are in low water, it will be reduced to -- to the five (5) days a week, sixteen (16) hours a day. So that adverse water energy is red -- is subtracted out because when we are in those dependable conditions we don't have to -- we don't have to provide that energy. So we're not -- we're counting on not providing that energy when it -- we're in the lowest of flow conditions. And that gives us our next exports.

From there we get our system surplus and deficit. And then the other item that's on the supply/demand tables is the exportable surplus. And the two (2) items that are deducted to get us to exportable surplus is one (1) Brandon Unit 5 because under the Manitoba legislation, under the Climate Change and Emissions Reductions Act, there are restrictions on operating Brandon Unit 5 and we cannot operate it to enter into long-term firm export sales. So we take that available energy off. We can use it to serve Manitoba load, but not to enter into new contracts.

The adverse water that is shown here as a reduction is again under some of the terms and conditions of the export contracts, sometimes we can financially settle. So we can leave the energy in Manitoba and deal with the fact that we were supposed to deliver to them on a financial basis. Again, we've said, If we're doing that, we're on low water conditions and so that energy would not be available for resale either.

And that's all I was going to go through on the tables. Are there any questions?

MR. BYRON WILLIAMS: Hi. Just -- sorry, Patrick. Did I bump you? Just on those tables, if I look at the -- comparing the NFAT 2012 reference to the NFAT 2013 update and if I -- I know that the load forecast person will be coming later, but am I right, that if I take the selected years '20/'21, '23/'24, and '25/'26, that DSM is -- is lower in all three (3) of those years for the -- the 2013 update?

MS. JOANNE FLYNN: Let me just find where you are. So 2021/'22, is that one (1) of your years, Byron?

MR. BYRON WILLIAMS: I -- I just peeked at -- at three (3) of the years, '20/'21, '23/'24, and '25/'26. It looks like, at a quick glance, that DSM is lower under the update in all three (3) years?

MS. JOANNE FLYNN: Yes, you would be reading the tables correctly. But, yes, I would remind you that all the numbers are still subject to confirmation.

MR. PATRICK BOWMAN: It's Patrick Bowman. It is just related to the same set of tables. The 2013 update lists different numbers for the base load forecast and for the base DSM forecast, but they both are referenced as the 2012 forecast, the same as the previous version. Is that meant to be a new round of forecasts, in fact, not 2012 again?

MS. JOANNE FLYNN: Correct. That -- that should be 2013, yes. Any -- any other questions? Okay, is there one (1) more? Okay.

MS. NICOLE FITKOWSKI: I have Erick Matthiesen.

MR. ERICK MATTHIESEN (VIA CHAT): Do you have or is there a future prese --
it says:] Future presentation that shows a levelized cost, megawatts per hour, for any of the new thermal, hydro, or imports that can be used as a target for competing alternatives or of other pricing schemes?

MR. ED WOJCZYNSKI: That's -- that's in the submission. But I don't think we were going to have it as part of the workshop. Joanne presented some numbers this morning on costs, but that was sort of some MISO old numbers, so we didn't see that as being part of the two (2) days.

Are there any other que -- are there any -- this is the handheld mic. It's a new kind. Are there any other questions before we take the break? And then, after the break, Lois Morrison will be presenting on the load forecast.

Okay, well, why don't -- it's 2:42. We said we'd start at 3:00 with the load forecast. So why don't we just stick to that, it's a nice round number, and take a break. And I guess most of us will be hanging around if you want to ask us something on the break anyways. Okay, thanks.

--- Upon recessing at 2:42 p.m.
--- Upon resuming at 3:00 p.m.

MR. ED WOJCZYNSKI: So if we could perhaps get started. I -- I've got most people in the room. I'll take a look out in the hallway.

(BRIEF PAUSE)

MR. ED WOJCZYNSKI: Okay. So let's get started. And we have the illustrious Lois, who will present on the load forecast. I do note that this is not intended to be a DSM for -- presentation. I could see we'll be getting into DSM with -- with -- in some -- with some interesting discussion down the road, but today's presentation is focussing on the load forecast itself. Although, of course, there's always a bit of overlap. Lois...?

PRESENTATION RE: MANITOBA HYDRO'S LOAD FORECAST:

MS. LOIS MORRISON: Okay. Hello, everybody. I guess they'll bring up the presentation shortly. And I've been allotted and hour and I will do my darnedest to get through this as quickly as possible so that we have an opportunity to discuss any topics that might be of interest to everyone.

(ON SLIDE 1)

MS. LOIS MORRISON: And to begin with, the load forecast is a key input into our Power Resource Plan inter -- our integrated financial forecast. It's a -- our forecast is prepared annually and we make adjustments annually to bring it -- bring into consideration the most current market information at that time to present the most likely case.

(MOVED TO SLIDE 2)

MS. LOIS MORRISON: When -- when I was asked to present today, I was asked to present about the...

(BRIEF PAUSE)

MS. LOIS MORRISON: This is going to be a little awkward for me. I'm used to being able to move around. And being tied to one (1) spot is a little uncomfortable.

So -- so I was asked to come and talk to you today about our 2012 forecast and the methodology or how we produce our -- our forecasts. And I'm also going to speak a little bit to variability and accuracy, which is also a very key consideration in any forecasting, and then provide a brief update on the 2013 forecast.

As I mentioned, we update our forecast annually, and we have just recently completed the update to the forecast to reflect the 2013 information.

(MOVED TO SLIDE 3)

MS. LOIS MORRISON: So when we forecast, we forecast each sector individually. So we -- when we're preparing our forecast we prepare our forecast for our residential sector, our general service mass market sector, and our general service top consumers.

And with those forecast -- and each of those forecasts are done in a dif -- with a different methodology, a methodology that suits those markets specifically. Each forecast also starts from actual data. So for the 2012 forecast we would start the forecast from the actual consumption that was realized in the '11/'12 fiscal year.

(MOVED TO SLIDE 4)

MS. LOIS MORRISON: So I'm going to talk to each sector individually. The first sector I'm going to speak to is the residential sector. And as I mentioned, we start with the 2011 actual data. And in the -- we use the weather-adjusted actuals for the '11/'12 fiscal year. The consumption in that year was

7,114 gigawatt hours. What we are forecasting the growth to be in the -- under the 2012 forecast is we're forecasting it to grow to 9,760 gigawatt hours in 2031/'32. This represents a growth of approximately 1.6 percent per year over the next twenty (20) years.

The primary drivers of growth in the residential sector are population. And under the 2012 -- under our most recent forecasts is the market share of electric heat. And I'll go into more discussion about that later on in the presentation.

(MOVED TO SLIDE 5)

MS. LOIS MORRISON: So I'm just talking -- going to talk briefly about the methodology for the residential sector. In the residential sector, we -- the -- the market itself is relatively homogenous. And as a result of that, we do our model based upon a end-use forecast. And with that -- so we look at -- within the residential sector, we look at the end uses and forecasts up from those end uses.

The key data that we bring into that analysis is our economic out -- from our economic outlook, we bring in our customer forecasts. We bring in our energy price forecasts for electricity and natural gas. We also bring in customer -- information from our customer information database, energy consumption and such.

And we also bring in information from recently completed residential energy use surveys. We regularly survey the market to get an idea as to what customers are using, what they're -- what the saturation of different appliances are, how they use those appliances, and such. All of that information is used to produce the residential end-use forecast. That survey and billing information are inputs into our conditional demand analysis, which provides us with our average usage per appliance.

So then we take our customer saturations -- sorry, we take our custom -- our -- our forecast for customer growth, and we allocate that out to -- to what we believe -- what -- we allocate it out to growth within Winnipeg, south gas-available area, and the nor -- and the non-gas-available areas. And then we build our forecasts up from there.

And we allocate based on the saturations from our surveys what the end use -- what the average usage is within each of those sectors forward. After we've produced this forecast, we subtract the forecast savings as a result of future codes and standards -- or future savings as a result of current codes and standards in place.

Standards such as -- or codes such as the energy component of the Part 9 building code, which requires elevated insulation levels and a number of other measures, those are all incorporated into a reduction that reduces this forecast to represent that -- those improvements as a result of codes and standards. The other thing that we do at this point is, we add on the forecast for electric vehicles for this sector.

(MOVED TO SLIDE 6)

MS. LOIS MORRISON: So I mentioned briefly what's driving growth. So -- so really the -- the key components driving growth in the residential sector are the population. And, as you can see, this -- this graph is demon -- is -- is depicting the annual population growth that we've seen historically -- that's the blue line -- and what the forecast growth under the 2012 forecast was for future growth.

And we can see that in the years leading up to the -- or the lead -- the years after approximately 2005/2006, we're seeing a substantial increase in the number of customers -- or the number of people moving into Manitoba. And that forecast is going forward at -- it represents a -- a growth of about 1.2 percent per year in the future.

(MOVED TO SLIDE 7)

MS. LOIS MORRISON: The other item that I spoke to that's driving growth in Manitoba is a increased market saturation of electric space heat in areas that have gas available. And these are the results from our 2009 residential energy use survey, where we identified that there was an increasing penetration of electric heat for space-heating purposes and for water-heating purposes in the marketplace.

And this was driving some of the increase in our forecast. It was not driving the substantial portion. As I mentioned, the population drives the majority of the growth in our -- in our forecast. Or the population forecast drives the majority of our growth. This contributes to the growth.

So you can see in the south gas available area, houses built in 2005 to 2009, 63 percent of the homes built were installing electric heat for space-heating purposes, whereas in previous years that was closer to approximately half. So this was what was -- what we were observing.

The other item that we're observing is an increase in electric water heat. And this is a result of changes in regulations for natural gas furnaces. And we discussed this at length during the electric GRA hearing related to the requirement for no more chimneys. Sorry, there's not a requirement for a chimney as a result of the high-efficiency furnaces going in. As a result, the builder's choice, in most cases, is to put in an electric water tank. We're also seeing some of the market where the replacements are going in where customers are being up-sold to electric water heating.

Now, I'm going to jump ahead a little bit. We've made adjustments in the 2013 forecast to address some of these issues that were raised as a result of these findings.

(MOVED TO SLIDE 8)

MS. LOIS MORRISON: So now I'm going to talk a little bit about the general service mass market. Now, the general service mass market is all of our commercial and industrial customers except for the top consumers, or the -- the seventeen (17) largest consumers in Manitoba. So this would encapsulate all of the other commercial and industrial customers.

And again, for this forecast we would start with the 2011 actuals. So in 2011/'12 we had actual consumption of 8,270 gigawatt hours. That then is forecast to grow under the 2012 forecast to 11,497 gigawatt hours, which represents an average growth of 1.7 percent per year over the next twenty (20) years.

The factors that drive growth in the commercial and industrial, or the general service mass market are, population and GDP.

(MOVED TO SLIDE 9)

MS. LOIS MORRISON: So speaking to how we do our forecast for the general service mass market, as I mentioned, each sector is done with a different approach, and that approach best reflects that market.

Now, in the general service mass market, the -- the market itself is less homogeneous. There's more sectors that use energy in different ways. And as a result, what we do here is, instead, we do a forecast of customer growth based on an econometric model. And so what we do is we take information from -- again, from the economic outlook, the number of residential customers, and the Manitoba GDP, and for each percentage change in the gross domestic product and the -- and the number of customers, we have a change in the number of commercial cus -- commercial industrial customers, or general service mass market customers. So that forecast of customers, or that increased number of customers.

What we do then is we take that forecast, and based on historic distribution among the four (4) rate categories that Manitoba Hydro has for general service, we allocate them out. Tho -- we allocate that growth out among those four (4) categories. And then we apply the five (5) year weather adjusted average use for each of those four (4) rate categories to create the forecast overall for the general service mass market.

Those are all accumulated together. And then we -- again, we remove the forecast for the impact of future codes and sta -- standards, and we add on the forecast for electric vehicles.

Byron...?

MR. BYRON WILLIAMS: Yes, it's Byron. It's -- this question will be familiar to you from the last GRA. But you've -- Hydro's, I -- I think, been telling us that they're looking at rate increases exp -- expected 3.95 percent for each of the next seventeen (17) or eighteen (18) years.

And for this particular aspect of the marketplace, how does the load forecast account for the consumer reaction to price increases? Like, most American models I've seen factor in some elasticity in terms of demand, and I'm just trying to refresh my memory in terms of for this marketplace what you did.

MS. LOIS MORRISON: Under the 2012 forecast we had a component where we looked at the price differential between electricity and natural gas on the residential sector. And that was more so to determine whether people made a fuel choice for space heating to be electric or gas. That was what -- that's where we found a relationship in past analyses.

In the general service mass market sector we regularly go back and look at, okay, what could be influencing growth, what could be influencing fuel choice, things like that. And what we have found to-date in our analyses is that there isn't a strong relationship between price and growth in the commercial sector.

We've traditionally had markets where

our -- our prices have been -- managed to be -- the price increases have been relatively stable, and increasing in -- in stable increments. And so that may be what's driving that lack of a relationship, but generally we haven't seen that relationship arise in any of the past analyses that we've done from looking at the historical data.

MR. BRUCE DUGGAN: Can you tell me what the average rate of increase has been say for the last ten (10) or twenty (20) years? Like -- like if -- like Byron says, if it's projected at three point nine (3.9) --

MS. LOIS MORRISON: M-hm.

MR. BRUCE DUGGAN: -- what's it been the last decade or so? Do you know?

MS. LOIS MORRISON: In terms of the growth in the commercial sector?

MR. BRUCE DUGGAN: No, the rate increase.

MS. LOIS MORRISON: The rate increase?

MR. BRUCE DUGGAN: Like if the rate increase has been, I don't know, 1 percent and now it's suddenly going to go to 4 percent...

MS. LOIS MORRISON: I don't know that off the top of my head as to what our average rate increase has been annually over the last ten (10), twenty (20) years.

MR. BRUCE DUGGAN: I guess I'm -- I'm -- I have to say I'm -- I'm kind of dubious about the idea that there is no relationship, or no reliable relationship between price increase and demand.

MS. LOIS MORRISON: I'm not saying that there isn't one. What I'm saying is that to-date the analysis that we've undertaking, looking at the historical growth and there -- the -- the factors that may be determining it, there is a greater relationship -- statistically there's a greater relationship between the population growth and the GDP, as opposed to the price of electricity and natural gas.

MR. BRUCE DUGGAN: But the -- the problem, it seems to me, that the PUB is going to face without some kind of calculation like that, is they're going to have to decide whether or not it's in the province's best interest to spend $20 billion on a capital investment. And the alternative -- one of the alternatives --

MS. LOIS MORRISON: M-hm.

MR. BRUCE DUGGAN: -- is to raise the price. And I think we would agree at some rate of raise that capital expenditure becomes unnecessary because people cut back. We just don't know where that is.

MS. PATTI RAMAGE: I think we are getting into the area of argument and cross now --

MR. BRUCE DUGGAN: Sorry, I --

MS. PATTI RAMAGE: -- if you can just keep the questions on the material --

MR. BRUCE DUGGAN: Yeah. I am trying to understand how you calculate load without factoring in the effective price. It seems to me --

MS. PATTI RAMAGE: But I think you got the answer...

(BRIEF PAUSE)

MS. LOIS MORRISON: Regis would like the mic.

Mr. Gosselin...?

MR. REGIS GOSSELIN: There's been a policy change at the federal level with respect to immigration, which occurred late last year. And I -- I guess you've assumed -- for the purposes of your projections you've assumed that there's been -- there will be no impact related to that policy change?

(MOVED TO SLIDE 10)

MS. LOIS MORRISON: So what we see here is what we had forecast -- what we had as the forecast for population under our 2012 forecast. And that -- that forecast is a compilation of forecasts that we purchased from vendors that provide these types -- that sell forecasts. And this was, you're right, correct, before the federal government made adjustments to their -- their immigration policy. What we've done since, as I mentioned, is we -- every year we update our forecasts based on what is the more current and new information, and therefore we've adjusted our '13 forecast to reflect the new updated forecasts that we are being provided by the people that we purchase forecasts from.

And so skipping ahead, yes, there is a reduction in the forecast for population. As I mentioned here, this represents about a 1.2 percent average increase in population. Under the revised figures, they're forecasting a 1.1 percent increase as opposed to the one point two (1.2).

So there's still an increase projected in the forecast for population in Manitoba, but it is at a -- at a slightly slower rate.

(MOVED TO SLIDE 11)

MS. JOANNE FLYNN: As I mentioned, one (1) of the driver's for growth in the general service mass market where we found a relationship, or a stronger relationship, when we look back at our historical growth, is that as our population grows, and our number of residential customers increase, the number of commercial services and indust -- our -- our commercial customers, or our general service mass market, also increases. And that is -- it makes sense when you think about the fact that the more people and the more houses in Manitoba, the more services that come to meet the demands of those people in those houses: more schools, more public -- more healthcare.

So these types of services will move in to meet the need of the growing population. And so that is where we -- that's where that factors into that part of the forecast.

The other thing that we mentioned, and this is rather intuitive, is that if we are forecasting growth in the economy in Manitoba, then likely there will be growth in the number of commercial and industrial customers.

So our forecasts have provided us with

an increase that we're anticipating seeing slightly more than 2 percent growth in the near term, and then averaging out to be about 1.9 percent growth in the years following on average.

(MOVED TO SLIDE 12)

MS. JOANNE FLYNN: The other item of interest -- and as I mentioned the primary driver's for growth in the general service mass market sector are population and GDP. However, what we're also seeing -- is that customers today are using more energy than customers in the past.

So if you look at the -- the 1, 2, 3, 4 -- fourth column over from the left which says -- states "Average Use in Kilowatt Hours Per Customer," and you look at the 2011 which is the bottom row, you'll see that the average customer in 2011 was using 1,000 -- 126,000 kilowatt hours a year, and then if you compare to each year prior, those are five (5) year increments, you can see that they were using substantially less.

So what we are seeing is that of the customers that are connecting in more recent years, and the average use of the customer is increasing over time.

(MOVED TO SLIDE 13)

MS. JOANNE FLYNN: Going to the general service top consumers sector. Again as I mentioned everybody is treated -- everybody is forecast in a little bit different way. The -- what is consistent is we do start with the '11/'12 actuals for the sector. In 2011/'12 the top consumers consumed 5,531 gigawatt hours. This is forecast to grow to 7,698 gigawatt hours in 2031/'32. This represents a growth of 1.7 percent annually over the next twenty (20) years. Over the last twenty (20) years this sector has grown by 1,800 gigawatt hours.

(MOVED TO SLIDE 14)

MS. JOANNE FLYNN: So how we approach this sector, as I mentioned, is -- is different. This sector repre -- we have seventeen (17) con -- consumers representing about twenty (20) -- thirty-one (31) customers. So each customer is forecast individually.

We work with our major account reps and our key account reps who work quite closely with these individual customers to identify what their short-term confirmed and committed projects and plans are to get an idea as to what they're going to be doing over the next few years.

So we're looking at about a one (1) -- about a three (3) -- one (1) to three (3) to four year period. What are they -- what have they confirmed they're going to be doing? What are their -- what are -- what's in their actual plans?

And this includes any shutdowns, cutbacks, any expansions, that type of -- of planning. So those forecasts are then included in our short-term forecast for those top consumers. But when we go to look at the long-term, how do we forecast for this sector from the long-term?

What we do is we -- we take an average expected growth for all top consumers forecast together. And that's what's been referred to as 'the potential large industrial load forecast'. We discussed it at the electric general rate -- rate hearings. And that is where...

(MOVED TO SLIDE 15)

MS. LOIS MORRISON: I went back. Oh,

no, sorry.

So -- and -- and how we come up with the potential large industrial load forecast is we look at the historic load growth that we've seen in this sector. This sector is very much influenced by the economy for their specific sectors.

So the -- the primary metals and mining sector will be primarily influenced by the economy for that industry, not necessarily Manitoba alone. So there -- there's things that driver their growth that are -- that we feel that it's better to look at the overall industry as a whole as opposed to trying to predict each sector.

So we look at the -- the overall growth in the his -- over the past twenty (20) years and what have we seen. And so what we look at -- and we -- we include in our analysis any customer -- Company expansions. We include any cutbacks and shutdowns, and any new startups that were greater than a hundred gigawatt hours.

So just to draw your attention, so we look at the last -- the last period of 2003 to 2012. During that period of time we saw four (4) expansions, one (1) new customer, and the loss of one (1) customer, which was quite extensively discussed and has been quite prevalent in the media.

Now, the net growth over that period of time was 200 gigawatt hours. So even with the loss of that substantial load we still saw a net growth in the overall industry of 200 gigawatt hours.

The other section that we look -- the other period that we're looking at here is the period of 1993 to 2002. And during that period of time, we saw five (5) expansions, three (3) new customers, and the loss of one (1) customer. That growth over that period of time was 1,600 gigawatt hours. So over that total period of time, as I mentioned, we saw 1,800 gigawatt hours of growth.

Now, this growth, if you were to go back five (5) years or ten (10) years before any one (1) point on this graph, that growth or -- or contraction would not have been represented in the individual forecasts of the companies. And they -- so this is the ty -- this is why we're looking at it from this perspective.

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MS. LOIS MORRISON: So we forecast -- for the potential large industrial load we use a -- an estimate of a hundred gigawatt hours a year because we can't predict specifically what year that large growth -- that large load may arrive or -- or that -- that shutdown may occur or that market contraction.

So what we do is we estimate an average of a hundred gigawatt hours a year. And we -- every year we revisit to see is that still a reasonable approximation to use for forecasting for the general -- for the potential large industrial loads.

And so what you can see here is the analysis that we prepared when we looked at the ninet -- the 2012 forecast. We looked at, okay, well, over the last twenty (20) years we've seen growth of about 92 gigawatt hours a year. Is the hundred gigawatt hours a year still reasonable? Yes. So that's why we -- we use a hundred gigawatt hours a year.

The hundred gigawatt hours a year represents 1.3 percent annually in growth. And the 92 gigawatt hours a year represented about 2 percent growth annually in the years leading up to 2011/'12, thirt -- 2011/'12.

(MOVED TO SLIDE 17)

MS. LOIS MORRISON: So as I mentioned,

all of these sectors add up. We add on transmission losses, distribution losses. We add on some other smaller loads, such as area roadway lighting, a number of those things, to come up with our overall gross firm energy requirements. This represents the future requirements for our integrated system.

And what we're seeing here is that we had consumed 24,367 gigawatt hours of energy in 2011/'12. We're forecasting it to grow to thirty-three thousand four hundred and twenty-five (33,425) by 2031/'32. And this represents a growth of 1.6 percent per year over the next twenty (20) years.

(BRIEF PAUSE)

MR. BYRON WILLIAMS: Hi, Lois. I'm just curious if you've looked at what other utilities are doing in terms of their future large industrial load post-20 -- 2007? You -- you know, I've certainly heard of some American jurisdictions that are -- are revising their forward-looking estimates for large load, more -- more materially than -- than you might -- might be doing.

MS. LOIS MORRISON: It's -- it's something that we do keep in mind very closely when we're doing our general service -- or our top consumers forecast. The interesting thing -- and most of you, I'm sure have heard this, is that during the economic downturn a lot of other areas saw significant drops in their industrial, or large industrial -- for the most part the general service top consumers are industrial loads.

We saw large drops in -- in their energy use, there's no question. The interesting things is that -- and -- that Manitoba rode it out, for the most part, to -- we didn't suffer it quite to the same extent. And a lot of that is because of the diversity of our industrial sector. When you go to other jurisdictions that have, say a really -- a very large pulp and paper load, or they have a large manufacturing, like vehicle manufacturing loads, those centres really suffered quite drastically.

But when you look at Manitoba's top consumers we seem to have a smattering of a little bit of everything. As a result of that we tend to not have as drastic drops but we also don't have the drastic highs either, the drastic growth that you might see in places like Alberta with the oil fields and such.

So we -- we are -- we are watching that and we are cognizant of it. However, we don't think --

we think that we're going to be pretty much very stable and see stable growth going forward similar to what we've seen in the past. So -- but you -- you are correct. And we do watch very carefully.

(MOVED TO SLIDE 18)

MS. LOIS MORRISON: So we -- we focus quite a bit on energy, but we do also look at peaks. So a lot of the changes driving growth that we've discussed to date affecting energy also affect our forecast for peak. In 2011/'12 under -- we had a peak of four thousand three hundred and eighty (4,380), that's a weather-adjusted peak. And we are projecting that that will grow to 6,032 megawatts in '31/'32, representing a 1.6 percent growth over the next twenty (20) years, 1 per -- 1.6 percent on average.

(MOVED TO SLIDE 19)

MS. LOIS MORRISON: So we've -- we've talked to -- to a great extent about what the forecast -- how -- how we build our forecast and what we do for -- what we're anticipating to see in terms of growth under the 2012 forecast. But we recognize that -- that inherent to all forecasts is uncertainty. And the forecast represents Manitoba Hydro's best estimate of what Manitoba -- Manitoba's future energy requirements are going to be.

However, we do, as I mentioned, recognize there's uncertainty. We use forecasts to project what our forecast is going to be. And so as such, what we do is a probabilistic his -- based analysis based on historical variation in our energy use, in our -- in our -- ba -- and what we do is we use that to determine what future variability we might see as a result of long-term economic effects.

So we look at the path and see how much did our load vary as a result of economic factors. And we say, Okay, well how much is our -- how much could our forecast vary as a result of that going forward. And that then drives how we present what varia -- what levels could be presented -- or could be anticipated in our forecast.

And so I -- I will apologize. This is one (1) -- one (1) of the -- the things that happen when you're working in two (2) forecasts at one (1) time. The -- what we're looking at here is the -- actually the 2013 forecast variability, but it -- it still represents the same information to the great extent.

Under the 2012 forecast, our analysis showed that the load could vary by anywhere from plus or minus 2,555 gigawatt hours. And what that represents is that -- or what that means is that, based upon our probability analysis, there's a 10 percent probability that the load could be greater than 35,980 gigawatt hours. So the -- there's only a 10 percent chance that it could be higher than that in 2031/'32.

And there's a 10 percent probability that the load could be lower than 30,870 gigawatt hours. So there's only a 10 percent chance of the load being outside of that parameter. So 80 percent probability that the load will be within those bands.

(MOVED TO SLIDE 20)

MS. LOIS MORRISON: The other thing that we look at, again on the theme of uncertainty, given that uncertainty is inherent in all forecasting, we are -- we're satisfied with the methodology that we've undertaken. But to -- to make ourselves comfortable, what we have done, and what we continue to do, is look at how accurate have we been in the past.

So what we do is we go back and we look

how accurate was our forecast from five (5) years ago? So for every single forecast we do, we go back and we look. How did we do? And our objective is to be within 1 percent for each year. So our objective for our forecast five (5) years ago was to be within 5 percent. And our objective for our forecast ten (10) years ago was to be within 10 percent. And what you can see here is that, for the most part, our forecasts have been within the 5 percent range, the majority of them.

(MOVED TO SLIDE 21)

MS. LOIS MORRISON: Looking at the 10 percent -- the ten (10) year accuracy, again the majority of our plans, or sorry, the majority of our forecasts have been within the 10 percent range.

(MOVED BACK TO SLIDE 20)

MS. LOIS MORRISON: What you will al -- what you may notice, and it's much more prevalent on the five (5) year accuracy chart because we -- we've had this -- we've had staff look at this and say, Well that looks strange. It looks like we're seeing this --

these -- these cycles of over-forecasting and under-forecasting.

Well, it's not so much cycles of over-forecasting and under-forecasting. What we do when we're forecasting is we're forecasting average expected economic growth or ac -- or -- or economic forecasts. We're not forecasting a period of extended growth or over -- or -- or extremely high growth or -- or an economic recession. We're not -- we're -- we're -- our forecasts are based upon a reasonably expected economic growth.

So what you're seeing here is the result of the five (5) year forecast being based on average growth but these are unexpected economic events. So when you look at 2012, you see the bar goes outside of the 5 percent. Well, that's because five (5) years before, no one predicted that in two (2) thou -- at the end of 2008, we'd be looking at what's been characterized as "the worst financial meltdown since the Great Depression." And I'm taking that as a quote from a report written for the US Government Financial Crisis Inquiry Commission in 2011.

So these types of events we don't forecast for. But that would be covered off within the variability that I just talked to, is that we're trying to -- to put ba -- bands around what economic impacts there might be going forward into the future.

(MOVED TO SLIDE 21)

MS. LOIS MORRISON: So -- but we're quite comfortable with our accuracy, and feel that the -- that our forecast methodology is -- is working quite well.

(MOVED TO SLIDE 22)

MS. LOIS MORRISON: So we talked a little bit about -- and I'm hoping I'm not going too far over time. We talked a little bit about the 2013 forecast, and how we've updated it for -- for the more current market information. And so, just to touch on the key points, the -- under the 2013 forecast, we are projecting load to grow to -- to three (3) -- 32,667 gigawatt hours in 2032/'33. We do twenty (20) year forecasts.

Now, of course everybody is going to be interested in the '31/'32 year so that we can compare it to the 2012 forecast. And so what I will say though is that comparing it to the 2012 forecast, we are now forecasting 32,600 -- sorry, 32,265 gigawatt hours by '31/'32, which is down from the thirty-three thousand four hundred and twenty-five (33,425) projected.

So in -- under the 2012 forecast we had projected 1.6 percent growth annually over the next twenty (20) years. Under this forecast, we're projecting 1.5 percent.

(MOVED TO SLIDE 23)

MS. LOIS MORRISON: The same thing has been observed in our projection for peak impact. We are now forecasting the peak to grow to 5,860 -- sorry, 5,886 megawatts in 2031 which is down from the 6,032 megawatts under the 2012 plan.

(MOVED TO SLIDE 24)

MS. LOIS MORRISON: Now, what's -- what's leading to these changes, as we discussed earlier, is that the population forecast has been decreased. The increase in the population has been decreased so the rate of increase.

So under the 2012 forecast what we were seeing was a forecast of 1.2 percent on average going forward. And under the 2013 it's been updated to be 1.1 percent on average.

(MOVED TO SLIDE 25)

MS. LOIS MORRISON: The other thing that we have introduced under the 2013 forecast is we have adjusted the forecast to reflect what we are anticipating to see as a reduction as a result of a num -- a number of heating fuel choice initiatives that we are putting in place.

This is all arising out of the results of the fuel-switching report, and we've talked about this at the hearings and -- but we are -- as mentioned, we are doing an education campaign for customers. We are looking at changes or we've -- we are drafting changes to our policies to encourage customers and home builders to make the appropriate fuel choice that's most economic for customers.

And so what we're seeing here is -- or what I'm demonstrating here is that right now in 2012/'13 the market saturation in the Manitoba South gas area for electric space heating is 47.8 percent being electrically heated. Prior to incorporating these adjustments we were anticipating that to grow to 54 percent. After these adjustments we're anticipating to hold it if not reduce it to 46 percent.

So that's one of the -- the factors that's contributing to the decrease in the 2013 forecast compared to the 2012 forecast.

(MOVED TO SLIDE 26)

MS. LOIS MORRISON: The same being said also for electric water heating. We're also looking at changes to help reduce the increased saturation of electric water heating.

(MOVED TO SLIDE 27)

MS. LOIS MORRISON: And those are contributing to a reduction in the 2013 forecast. And what we can see here is if you look at the third line, the energy forecast in 2031/'32, as I mentioned, under the 2012 forecast we had projected thirty (30) -- reaching 33,425 gigawatt hours of load or energy requirement.

That has been reduced by 1,159 gigawatt hours under the 2013 forecast. What we're seeing is a reduction in the ten (10) year annual growth rate from

450 gigawatt hours a year to 420 gigawatt hours a year, and also a reduction in the percentage growth rate correspondingly.

(MOVED TO SLIDE 28)

MS. LOIS MORRISON: For a comparison of what that looks like graphically, since we've looked at this a number of different ways, you can see that the -- the red line is -- the -- the heavy red line in the centre represents the 2012 forecast. The heavy yellow line in the centre represents the 2013 forecast. And the bands around represent that variability, or the -- the range of variability that we had talked about that could result as a -- due to economic effects.

And, so what you can see here is that the 2012 and '13 forecasts both fall within their ranges.

(MOVED TO SLIDE 29)

MS. LOIS MORRISON: And finally -- I think I'm finally, hopefully. Boy it's -- it could only have been worse if you guys had booked this for a Friday afternoon, right. I'd -- I'd have no one here.

The forecasts, as I mentioned, just to sum up -- these are the points that I'd like to leave us all with today. Our forecast is updated annually to reflect the most current available data at that time. We forecast -- our forecast models and methods are adjusted whenever appropriate to make improvements and to help us better understand how customers use energy.

And finally, our fore -- and finally, what provides us with comfort is that our forecasting accuracy over the long-term demonstrates that our methodologies are reasonable and reliable.

(BRIEF PAUSE)

MR. REGIS GOSSELIN: In the Centra Gas application that's currently being considered by the gas panel at -- at PUB there was evidence submitted by Centra Gas that they had changed their weather adjustment formula to reflect a twenty-five (25) year average as opposed to a ten (10) year average.

And I'm just wondering, the weather adjustment formula that's being used by Manitoba Hydro for the purposes of this submission, is there -- has there been a change in the formula?

MS. LOIS MORRISON: No. We are

consistent between both the gas side and the electric side. We use twenty-five (25) year weather adjusted for both forecasts and have done so for a number of years.

MR. PATRICK BOWMAN: Hi. Patrick Bowman. To what extent, if at all, do you take into account potential extensions of gas system or a broader service area for the gas utility in -- in southern Manitoba? Is there -- is it all -- at all built into the -- you define the three (3) areas. But I didn't know whether there was any change in the boundaries between the areas assumed.

MS. LOIS MORRISON: With -- the south gas area is the area you're referring to. And with that we are -- we have allocated out based on historical -- what we did was we looked at the historical allocation of how -- how many gas houses are put in or gas subdivisions are built and such.

And we then -- our forecasting -- what we did with this under the 2013 is we essentially said we -- we expected more of them to come into play as a result of -- of our efforts.

But on the gas side of the business there is a different feasibility model and there's a different costing to bring gas in. And so we didn't specifically say, Well -- we didn't go out and map, you know, this town is this close to gas and it would cost this much to bring service out to that point.

For the most part, any major gas expansions at this point in time are very costly. And when we've looked at it even in probably about -- thinking about -- it has to be almost ten (10) years ago when we looked at it in the southwest corner of the province, there -- we looked at a major gas expansion. And the only way it would have been viable is if we could have brought on board federal dollars to support it. And so the original plan for that expansion was made quite a bit smaller and focussed only on areas where there was substantial load to support it.

So for the most part, I don't think you're going to see major natural gas expansions beyond where we are now. There's -- there has to be population density to support it or a major industrial load.

MS. NICOLE FITKOWSKI: Bill Harper has a question.

MR. BILL HARPER (VIA CHAT): Is the variability shown for the load forecast reflective of just potential variation and economic GDP outlook? Would it be greater if one also looked at possible variations in population growth?

MS. LOIS MORRISON: The -- the variability is reflective of what we would deem to be all economic factors. Like it -- it would include population. It would include -- or population growth. It would include changes in GDP. It -- what it reflects is the ec -- is the economic effects outside of weather, so what could -- what variability we could see outside of weather.

(BRIEF PAUSE)

MS. NICOLE FITKOWSKI: Dave Lamont says...

MR. DAVID LAMONT (VIA CHAT): Aside from codes and standards, what assumptions were made about energy efficiency programs?

MS. LOIS MORRISON: The energy efficiency programs specifically are -- okay. The future forward anticipated savings from the Power Smart programs are represented as a separate plan. And as Ms. Flynn mentioned, they are removed from the forecast and -- as a separate line item.

What we deem is that any savings achieved to date under our Power Smart plans are reflected in the fact that we are using the starting point as actual data for -- for the 2011 or the 2012 forward forecast. So any savings that have been achieved under programs to date have already been realized and are reflected in that actual value.

When we look at what's going forward, so -- so the person who goes to insulate their home tomorrow, those savings are reflected in the DSM values. And those would then be taken off of the load forecast under the analysis Ms. Flynn referred to.

(BRIEF PAUSE)

MR. REGIS GOSSELIN: In the -- in the US data that I've seen published by the federal government of the United States, they -- they were listing the projections of energy consumption over time for various regions of the United States. And -- and the -- what they're projecting is considerably lower than -- than what Manitoba Hydro is forecasting for this particular preferred development plan.

So I'm thinking, for example, as I recall, MISO is -- the MISO region is projected to grow at 0.8 percent over roughly the same time frame that Manitoba Hydro is forecasting double the growth. And the MISO growth projection in itself is -- is in -- in many cases higher than other regions of the United States.

And I'm -- I'm -- I guess one (1) of the questions that intrigues me is why would there be such a signi -- significant difference between what you're projecting at Manitoba Hydro relative to other nearby regions, has an impact as well with the projected demand by US counterparties. So in other words, it has -- it seems at odds with what -- what is going on in the United States, but it also suggests that there will be less demand from MISO than would otherwise be the case if -- if they had a higher projection.

Could you comment on that generally?

MS. LOIS MORRISON: I -- I can't comment on the impact of a lower demand in MISO territory but, yes, there are other jurisdictions that are projecting lower growth. We are -- we recognize that. But what we've been realizing in the grow -- is that we have seen that increase of growth in Manitoba and we -- a lot of our growth, as I indicated, is -- is tied to the population growth and we are expecting to see growth at a higher rate than other areas of Canada when you -- when you look at the overall growth in other jurisdictions in Canada where they're projecting growth of around 1 percent per year annual growth in population. And ours is at a higher rate. We're projecting a higher rate. So based on the forecast that we've -- we've purchased from different providers.

MR. ED WOJCZYNSKI: Maybe a -- a comment on -- in the MISO -- and Dave or Joanne can comment as well, but a -- a big factor in the MISO area, aside from any load growth that's there is the fact they're going to be shutting down so much coal generation and they need to replace it. And even if they had zero load growth there would still be a -- a demand for resources. There's even nuclear plants being shut down as well as coal, for example.

So it's -- the load growth, I'm not sure that we've prioritized what the drivers are but I certainly wouldn't want to -- I don't think Manitoba Hydro is saying the MISO load growth is the big driver on the export side.

MS. NICOLE FITKOWSKI: Dave Lamont has a question.

MR. DAVID LAMONT (VIA CHAT): So is the forecast you presented inclusive of this DSM or is it just adjusted out later?

MS. LOIS MORRISON: This forecast is inclusive of all codes and standards. It is adjusted later to represent what we would consider being market-based DSM efforts.

(BRIEF PAUSE)

MR. ED WOJCZYNSKI: Lois, I was just talking to Louis here, and the other thing you -- I don't think you mentioned about Manitoba different than other jurisdictions from the load growth was the fuel switching issue, right?

MS. LOIS MORRISON: Yes, but we're putting initiatives in place to help mitigate that.

MR. ED WOJCZYNSKI: When you mitigate, is that going to eliminate it or just reduce it?

MS. LOIS MORRISON: No, it -- it -- even -- even though we call it the 'south gas available area', it's what I referred to earlier as, just because it's called 'south gas available area', it doesn't mean that every -- everywhere within that area can economically access gas. So there will still be growth of electrically heated homes in those areas.

MR. ROGER CATHCART: I have a very quick question. Roger Cathcart. What report are you referring to that shows the growth on immigration in Manitoba being higher than other parts of the country?

And how does that tie out with the load growth found in those jurisdictions? And have you reconciled the relationship between load growth and immigration in, let's say, Ontario, Quebec, British Columbia, versus Manitoba?

MS. LOIS MORRISON: I will have to get that for you. What I'm referring to is, based on memory, a discussion I had with our economic analysis group, who provided me with the information related to our forecast and population. So that's outside of my area of expertise. I apologize.

MR. ED WOJCZYNSKI: Maybe a small tidbit, also is that, as I understand it -- we don't have the economic analysis people here. But as I recall, we are actually using immigration forecasts that were lower than what the provincial -- the province was officially forecasting. Because we were tak -- trying to be realistic.

Is that -- do I recall that correctly, Lois?

MS. LOIS MORRISON: It is lower than what the province had been forecasting. What we do is we purchase -- if I recall, again I'm going on memory, which is -- we purchased three (3). I -- I think it was three (3) forecasts we purchased. And we take a consensus of those three (3) to produce the forecast that we use for our -- for our load forecast.

(BRIEF PAUSE)

MS. LOIS MORRISON: And I should note that the -- although we do talk a lot about the immigration policy being a significant contributor to that growth -- again I'm going on memory. The -- there -- one (1) of the forecasters who provided us with a forecast doesn't look at that policy. What they were looking at was the requirement to meet future employment needs related to people retiring, and people aging, and -- and such like that.

So although we do talk a lot about the immigration policy, one (1) of the -- it -- it's not the only factor that's con -- included or considered in the forecasts that we have purchased, and are a part of that consensus forecast that we use.

MR. ED WOJCZYNSKI: Maybe just two (2) other tidbits on this load growth side that the illustrious peanut gallery of Dave and Joanne pointed out. One (1) is that the -- the -- your -- the forecast you'd be talking about in the MISO area, for example, would be net of DSM -- of new DSM, whereas, what we're talking about here, on a going-forward ba -- basis, does not yet have the new DSM in it. And so it's a gross. And our historical load growth is also net of DSM.

So that changes the numbers slightly, right?

MS. LOIS MORRISON: Yeah.

MR. ED WOJCZYNSKI: And the other thing is, we were talking about low load -- low load growth in the MISO area. But Saskatchewan next door, who as we all know is doing quite well economically, they're looking at 3.4 percent load growth over the next ten (10) years, which is why Dave is talking to them, or they're talking to Dave. So it -- and we're not booming like Saskatchewan but we're actually doing pretty well.

This is getting interesting. Some more questions? Particularly, Lois really likes to be grilled, so -- but seriously, are there some more questions, either on what Lois has just talked about or what any of the -- of the rest of us have talked about?

I see there's two (2) questions back there. So you got things going, Lois.

DR. PETER MILLER: This is kind of on the edge of what you talked about today, and it has to do with the DSM potential study because many of the methods are the same, are they not?

And what do you do differently with a DSM potential study than you do every year here?

MS. LOIS MORRISON: A DSM potential study is substantially different than what we do here. Here we have set models. In the residential sector we do do an end-use forecast but in the commercial sector, industrial sector, we do not.

A DSM potential study looks at end uses in particular for each sector. They look at what opportunities might be available in the marketplace. They look at when they're coming on. You look specifically at growth rates. You look at -- more specifically you look at equipment life and changeover, whereas within the forecast here we aren't looking to it in that great extent, specifically on the commercial and industrial side. So it's a much greater undertaking.

DR. PETER MILLER: And of course the other question is: Will we see it?

MS. LOIS MORRISON: We are working very diligently to ensure that it's filed with the NFAT.

MR. BRUCE DUGGAN: I'll see if I can ask my question without it being a cross-examination.

That was not my intention.

Could -- could we ask in your presentation to the PUB if you would include the rate of increase that has happened? Like you -- you've gone backwards and said, The -- the consumption rate has grown by this much each year --

MS. LOIS MORRISON: M-hm.

MR. BRUCE DUGGAN: If you could correlate that with how much the rates have increased. So if the rates have -- and then project forward what you see the rate increase is in the future. See if it's -- if it's a significantly bigger rate increase --

MS. LOIS MORRISON: M-hm.

MR. BRUCE DUGGAN: -- you would think, unless people have more money than they know what to do with, there would be some correlation.

MS. LOIS MORRISON: I -- I wouldn't disagree that there would be some correlation. I can't quantify it for you because we don't have the data to do so. We can look at it but we have to recognize that certain sectors may not be as driven by that component.

It -- it depends on how much the energy component represents of their cost of delivering services. So all those things would come into effect. But, yes, we can definitely --

MR. BRUCE DUGGAN: I'm just thinking for the -- for the benefit of the PUB --

MS. LOIS MORRISON: Yeah.

MR. BRUCE DUGGAN: -- if they could have that comparison.

MS. LOIS MORRISON: Yes. Yeah, I -- I can put that in. But -- I can try to put that in. I'll -- I'll see if we can do that.

MR. ED WOJCZYNSKI: Yeah. There's -- the -- the reality of us and our submission, if I can just interrupt for a second here 'cause I'm responsible for making sure we have a submission that's ready on August 16th, I don't think anyone here wants us to file it on August 31st -- we -- we have to meet that schedule -- is we have a full plate to get done what we already have on our plates.

MS. LOIS MORRISON: Yeah.

MR. ED WOJCZYNSKI: If there's something to be added, I expect that doesn't slow down getting what we already have on our plates done. Then -- it sounds like Lois is saying she might -- she will try to do that but I -- but right now I think it's more important that Lois and her team finish reviewing and -- and -- the study from the consultants and getting that finished, and writing their chapter for the submissions.

So if there's time left over then maybe something additional but I don't think we can promise that right now, Lois. You have to finish that submission.

MS. LOIS MORRISON: Okay.

MR. ED WOJCZYNSKI: No, I'm serious. That -- that's the struggle we're facing. That's not to say, that kind of thing that's been talked about can't be available for after the submission in whatever means. We've got interrogatories. I gather there was going to be a technical conference of some kind. I don't -- I don't know where that stands. But I think for the submission we can't really promise to do additional work right now.

MS. LOIS MORRISON: Okay. Maybe what -- can I -- Mr. Duggan, would it be all right then if I were to promise to try to get that work done. If I can't get it in the submission given that Ed's giving me the evil eye and, yes, I -- I don't want to be working any more weekends on this, that we try to get that in after, that we would try to -- we would look at it but it may not be in the actual submission then.

MR. ED WOJCZYNSKI: And I know that the idea has been there wouldn't be supplementary --

supplementary filings. I -- let's not call this a supplementary filing. This is giving you an advance interrogatory response.

Would that be fair? Because otherwise, we're -- we're not talking about supplemental filings and supplemental filings because this process will never end then.

MR. BRUCE DUGGAN: I don't have the status to be -- to do an interrogatory. I just think it would be helpful for them to know how much it's grown in the past and how much you're projecting it to grow in the future at some point, somehow.

MR. ED WOJCZYNSKI: Any other questions that -- jeez, we have another nine (9) minutes, according to my watch, but we don't need to take them. I don't see anybody jumping up and down.

Is there anybody from the external? Last chance. No?

Okay. The schedule for tomorrow morning says nine o'clock. Oh, sorry. Sorry. Thank you. Wednesday morning. I -- see how eager I am to... I'm actually the first presenter. So as per the agenda, we'll be talking about project description for the projects and the preferred plan, then capital costs.

Mr. Bowen over there is going to be

presenting that. Then I'll come back with how we selected the plans that we are evaluating and talking a bit about them. And also, as per the request, I'm thi -- I'm trying to remember who -- I think PUB made the request, talking a little bit about how the power resource plans have evolved from previous power resource plans. So there'll be a little bit on that, as well.

And then Joanne's going to talk a little bit briefly about what information will be confidential and not. So that is Wednesday. Any last questions or thoughts before we wrap up? Going once, going twice, three (3) times. Thank you. Have a good evening.

--- Upon adjourning at 4:07 p.m.

Certified Correct,

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Wendy Warnock, Ms.