MANITOBA PUBLIC UTILITIES BOARD

Re: MANITOBA HYDRO COSS WORKSHOPS

Before Facilitator: Bill Grant

HELD AT:

Public Utilities Board

400, 330 Portage Avenue

Winnipeg, Manitoba

May 11, 2016

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1 APPEARANCES

2	Regis Gosselin	)PUB Board
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5	Hugh Grant	)
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7	Bob Peters	)Board Counsel
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17	Patrick Bowman	)
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21	Bill Harper	)
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23	Bill Gange	)Green Action Centre
24	Peter Miller	)
25	Paul Chernick	)

1 APPEARANCES

2 George Orle	)MKO
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4 Christian Monnin	)GSS/GSM Group
5 Michael Weinstein	)
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7 Ian Chow	)International
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13	)Federation

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8 Manitoba Hydro 2006 Cost of Service

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10 MIPUG-5 Prefiled testimony of P. Bowman and A.

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1 --- Upon commencing at 9:03 a.m.

2

3 THE FACILITATOR: Well, good morning,
4 everyone. It looks like people are mostly settled.
5 I'm told that -- that that's picking up, I hope.
6 My name is Bill Grant. I'm going to be
7 operating as Sergeant Joe Friday of Dragnet for our
8 proceedings here. Hopefully things work out well.
9 I'd like to thank everybody to start with for helping
10 out to develop the structure for these workshops. I
11 think we have a -- a good structure to focus in on
12 issues as they -- as they have their importance.
13 So today's one relates to the
14 generation cost -- generation cost allocated to
15 exports, and the next -- net export revenue
16 implications. I'm sure everybody has seen a number of
17 the letters that have been going back and forth with
18 respect to undertakings and -- and the like. My
19 understanding is we have somewhat of an agreement that
20 undertakings will be answered on a best efforts basis
21 by Manitoba Hydro as they're able to do so.
22 And one (1) of the things that struck
23 me in thinking about our structure for today though is
24 that this rather new structure hearing for Manitoba is
25 one (1) that allows perhaps a little bit more

1 discussion of the issues. By that I'm thinking of
2 mainly the informed judgments that are required in the
3 cost-of-service studies. The parties may have a
4 different view on it.
5 Or if I can give an example, one (1)
6 that struck me as I read through was that the hydro
7 generation assets are classified across to energy.
8 Would it be better to look at something like load
9 factor or perhaps the past load factor methods that
10 are used in other jurisdictions, what is the best one?
11 So the opportunity here to have the
12 experts talking to the experts to discuss key matters
13 in the cost-of-service is an opportunity and we'll see
14 how things go. I also think we should get going
15 relatively quickly because I think maybe some of our
16 problems will sort themselves out as we get into the
17 meat of the matters.
18 The agenda today is long, especially
19 today, and quite detailed. I'm not sure whether I've
20 just been paranoid that there won't be enough time,
21 but we have the time allocations that are -- are set
22 up.
23 Manitoba Hydro, Kurt, I would
24 anticipate that they have been given the extra ten
25 (10) minutes, and we're going to take that off the

1 lunch hour. Is it the case that lunch is being
2 brought in?
3 MR. KURT SIMONSEN: No, we're all on
4 our own.
5 THE FACILITATOR: Okay, a little bit
6 shorter lunch. We'll run to the Subway then and back.
7
8 (BRIEF PAUSE)
9
10 THE FACILITATOR: One (1) of the items
11 coming up is that we are being recorded. And so out
12 of that, where people are doing questioning, and
13 particularly if anybody feels that they have to
14 interject, which I hope won't be the case, but they
15 may feel that way, then introduce yourself so that the
16 court reporting will have that on record.
17 Kurt and I will be taking down the
18 undertakings to be undertaken. And we hope to get
19 that sorted out so that there's no misunderstanding
20 about those undertakings.
21 I guess one (1) of the other things in
22 terms of a positive thing in terms of getting going is
23 I've been through a fairly recent experience in
24 British Columbia where they have tried to do many more
25 workshops much like this, a little bit different but

1 much like this, and it was a very successful
2 experience. I think everybody there felt they
3 understood the reasons for the cost-of-service
4 methodologies much better and the alternatives to
5 those, much better.
6 So hopefully this three-day workshop
7 here will be rewarding here as well in terms of a
8 better understanding of the process. So with that,
9 are there any questions?
10 MR. BYRON WILLIAMS: Yes, Mr. Grant.
11 It's Byron Williams, for the Reporter. And just you
12 referenced the exchange of letters. And my friend,
13 Mr. Monnin, and I had come prepared to make motions,
14 but I think Manitoba Hydro has clarifying comments
15 that -- that they'd like to share. And perhaps that -
16 - just for the comfort of our clients, if we -- we
17 could give them that opportunity.
18 THE FACILITATOR: Sounds good. I
19 think the -- Kurt's pointing out to me that Odette
20 should introduce the panel, we hope. And, as well, if
21 you could address Byron's question, as well.
22 Last of all, I'm not wearing a tie. I
23 haven't worn a tie for twenty-five (25) years. Any
24 parties that feel more comfortable without a tie,
25 please feel free to get comfortable. It'll also help

1 that, you know, if the free-for-all breaks out, and
2 you wouldn't be constrained by a tie if that were to
3 occur. Anyways, be comfortable is the main thing.
4 Hopefully we have some fun with this
5 during the three (3) days. And hopefully we get to
6 learn an awful lot. Odette, over to you.
7 MS. ODETTE FERNANDES: Thank you, Mr.
8 Grant. Good morning, Madam Chair, Chairman Gosselin,
9 and Board members Grant and Bell, as well as Mr.
10 Simonsen and Mr. Grant. For the record, my name is
11 Odette Fernandes. And I, along with Ms. Janelle
12 Hammond, who is seated to my right, will be appearing
13 as counsel for Manitoba Hydro during this process.
14 We understand that the workshop is intended to be a
15 discussion between the expert, so to that end this is
16 why I'm sitting in the back row for this workshop.
17 And hopefully my comments, if any, will be very
18 limited.
19 As Mr. Williams indicated, I did have a
20 discussion this morning with Mr. Williams and Mr.
21 Weins -- Weinstein regarding the exchange of letters,
22 and I believe we are all on the same page. And
23 Manitoba Hydro does intend to discuss the issues with
24 the Intervenor consultants as they arise. And to the
25 extent that we are able to provide a response we will

1 provide a response, with the understanding that any
2 questions requiring detailed analysis or a review of
3 Manitoba Hydro's model cannot be responded to while we
4 are sitting here in this room. And those will have to
5 be taken away.
6 In addition, as mentioned on a number
7 of occasions Manitoba Hydro's ability to respond to
8 undertakings will depend, again, on the number and the
9 nature of the undertakings, as I've indicated
10 previously that our costs of service department
11 consists of three (3) individuals who are in charge of
12 responding to a majority of these questions. So --
13 but we are definitely hopeful that we can provide high
14 level responses that are adequate and satisfy the
15 inquiries that are made today.
16 So in terms of introduction of our
17 panel, I will do that quickly. Directly in front of
18 me we have Mr. David Cormie, who is our power sales
19 and operations division manager. To his right we have
20 Kelly Derksen, who is the cost of service department
21 manager. Then we have Dr. David Swatek, who is our
22 system planning department manager. Then we have
23 Terry Miles, who is our power planning division
24 manager; Darren Rainkie, who is our vice president of
25 finance and regulatory and chief financial officer;

1 and Greg Barnlund, who is our rates and regulatory
2 affairs division manager.
3 And then seated, I guess, a couple of
4 seats to my right we have Mr. Mike O'Sheasy, who is
5 consultant from Christensen and Associates, as well as
6 Mr. Robert Camfield, who is also our consultant from
7 Christensen and Associates. And seated beside --
8 quickly, seated beside Ms. Hammond is Mr. Michael
9 Dust, who is the cost of service supervisor. And at
10 the end of the table we have Marnie Van Hussen, who is
11 the professional accounting -- accountant working
12 within the cost of service department. And then
13 Natalia Giraldo-Gomes, who is our regulatory
14 coordinator.
15 We note that the timeline is very
16 tight, and it's our intent to have our experts
17 qualified at the concurrent evidence portion of this
18 process, so we can immediately get into the
19 discussions to occur today. So if we can have our
20 witnesses sworn, and then Ms. Derksen will proceed
21 through our presentation.
22
23 MANITOBA HYDRO PANEL (GENERATION COSTS, GENERATION
24 COSTS ALLOCATED TO EXPORTS, AND NET EXPORT
25 IMPLICATIONS):

1 DARREN RAINKIE, Sworn
2 GREG BARNLUND, Sworn
3 DAVID CORMIE, Sworn
4 TERRY MILES, Sworn
5 DAVID SWATEK, Sworn
6 KELLY DERKSEN, Sworn
7 MICHAEL O'SHEASY, Sworn
8 ROBERT CAMFIELD, Sworn
9
10 THE FACILITATOR: Perfect. I think
11 we're ready for the -- the general presentation.
12
13 (BRIEF PAUSE)
14
15 MR. KURT SIMONSEN: For the record for
16 everybody, we have all new microphones in the hearings
17 -- rooms for the -- those of you who've been here
18 before. And hopefully it'll be user -- more user
19 friendly. I understand, Kelly Derksen, you're going
20 first.
21
22 PRESENTATION BY MANITOBA HYDRO:
23 MS. KELLY DERKSEN: Good morning. We
24 put together a presentation, sort of the Coles Notes
25 version, if -- if you will, of what we believe the

1 major issues are in our submission, as well as some of
2 the -- the key issues or themes that have emerged from
3 the preparation of the Information Requests.
4 We can't get through all of the slides.
5 I'm going to touch on the -- the -- excuse me, the
6 ones that we think are -- are key. And we may be able
7 to circle back at other points during the day and
8 touch on some of the others, time permitting and
9 issues permitting.
10 The first slide, actually slide number
11 3, really talks about the overall purpose of a cost-
12 of-service study, which is to take the Company's
13 overall revenue requirement and decide which customer
14 classes bear what responsibility for that revenue
15 requirement.
16 For the purposes of much of the
17 materials that we've prepared, we've based it on
18 PCOSS14. That was based -- what underpins PCOSS14 was
19 IFF-12, and in IFF-12, total revenue requirement was
20 approximately $1.7 billion. We'll talk a little bit
21 more in a -- a couple of slides thereafter.
22 This slide I put together -- you know
23 what, I think I was a little uncomfortable with some
24 of the discussions that were occurring at the pre-
25 hearing conference, this notion that once Manitoba

1 Hydro's revenue requirement is approved, that it
2 shouldn't matter who pays.
3 And the fact is, it does matter to
4 Manitoba Hydro who pays, and some of the reasons we've
5 -- we've bulleted, there. Importantly, we work with
6 customers on a daily basis, and it's important for us
7 to have relations that are amicable with -- with
8 customers.
9 Custom -- customers ultimately pay
10 rates. Rates are largely underpinned by cost -- cost
11 of service, so it matters. And it also matters from
12 the perspective that cost of service is the major
13 input into rate design, and rate design sends price
14 signals either to consume or not to consume.
15 That then impacts load, which impacts
16 our -- our planning. It impacts the next resource
17 that we have to put in place to serve that load. So
18 indirectly, it's all circular. It all works together,
19 and it's important for the Company.
20
21 (BRIEF PAUSE)
22
23 MS. KELLY DERKSEN: I'm going to skip
24 to slide 7.
25

1 (BRIEF PAUSE)

2

3 MS. KELLY DERKSEN: In this slide,
4 what we're trying to get out is that cost causation is
5 the primary consideration in terms of key principles
6 that underpin cost of service where practical.
7 It's -- there's obviously not one (1)
8 view of cost causation, and we will spend the next
9 three (3) days essentially -- at the heart of every
10 issue is -- is that. And, you know, the other thing
11 that I wanted to get out of this is we have rate-
12 making goals, and those rate-making goals often
13 influence how we view cost -- cost causation.
14 And I'll give you just a -- a quick
15 example. We have an overarching rate-making
16 philosophy in this province, both on the gas and the
17 electric side of our businesses. It's called postage
18 stamp rate making. And what that says is that every
19 customer who takes a similar service will pay the same
20 rate regardless of where they reside in the province.
21 And so at the highest of levels, one
22 might think that there's an inherent conflict between
23 postage stamp rate making and cost causation, which is
24 those who cause the cost pay for them. I tend to view
25 it a little bit differently. I tend to view it as

1 postage stamp rate making is sort of the overall
2 framework, if you will, for how we set rates in the
3 province.
4 And within that framework, then, that
5 helps us inform how we view cost causation. And it
6 helps us define our customer classes, for example.
7 Helps us define how -- that -- what kinds of services
8 that we provide, and -- and the costing of those
9 services in particular.
10 And so those things aren't at odd in my
11 mind -- at odds in my mind, at least. They work in
12 concert with one another, and -- and one (1) of the
13 key things I think you can take out of this is you
14 need to know the rules of the game before you can play
15 the game. And so that's -- that's how I view it. And
16 -- and rate-making principles and goals generally fit
17 in that same spectrum.
18
19 (BRIEF PAUSE)
20
21 MS. KELLY DERKSEN: This is a very
22 high-level view of the output of our cost-of-service
23 study for 2014. It's taking the Company's overall
24 approved revenue requirement at the time of $1.7
25 billion, and it shows how that eventually feeds down

1 into all -- allocated costs, and those allocated costs
2 by customer classes.
3 And I guess there are a couple of
4 noteworthy points on this slide. And first, in my
5 mind, at least, would be that generation and
6 transmission, as you can see, in terms of just the
7 shear magnitude of the dollars are the most
8 significant of the issues because of their mater -- of
9 their materiality. They represent about 75 percent in
10 this cost-of-service study. About 75 percent of our
11 total revenue requirement.
12 In terms of net investment, which I
13 haven't put on the slide, generation, which is the
14 focus of the day today and in terms of net investment
15 is about $6 1/2 billion, roughly. At least in
16 PCOSS14, and we all know that that is, in the upcoming
17 number of years, going to essentially double.
18
19 (BRIEF PAUSE)
20
21 MS. KELLY DERKSEN: I'm going to start
22 with the -- the generation of function now. We sort
23 of skipped through how we functionalize, classify, and
24 -- and allocate costs.
25 The -- the functionalization phase is

1 really about grouping your costs together in terms of
2 broadly the services that the utility provides.
3 Generation, a major one for Manitoba Hydro. We have
4 fifteen (15) hydro -- hydraulic generating stations.
5 I've listed them there. A number of other costs,
6 water rentals, mitigation fees, costs. We have
7 thermal generating stations. I'm sure that we will
8 talk a lot about purchased power. The next slide.
9 We have also our HVDC facilities.
10 Visually, they're a -- a pole and a wire. Probably no
11 different than any other pole and wire in terms of
12 what it looks like, but functions very differently,
13 and we'll talk about that momentarily. And we also
14 have moved our converter facilities. Dorsey and --
15 our intention, upcoming Riel into the generation
16 function also.
17 We have northern collector circuits.
18 We have a number of transmission lines in the -- in
19 the northern part of our province that basically
20 collects the energy from the -- from the generator in
21 order for it to be converted in -- in most cases to be
22 sent down our bipoles to the southern part of our
23 province.
24 We'll talk a lot about, in the next
25 couple of days, of, you know, what makes transmission

1 not all equal. And some of it, therefore, we've
2 treated as generation. Some of it we've treated for -
3 - in a -- in a traditional sense as transmission.
4 The next slide was a -- a slide that
5 Dr. Swatek was good enough to share with me. And I --
6 and I loved it so much that I -- that I needed to use
7 it. You know, the -- the -- there's a couple of key
8 things when I look at the slide that are noteworthy
9 for me, a non-engineer, and number 1 is the integrated
10 nature of our system. I think it visually is well
11 represented in this slide. And secondly, like, we
12 talked a couple of min -- moments ago that not all
13 transmission facilities provide or serve the same
14 function or the same role.
15 And I think this picture nicely
16 demonstrates that. We'll talk more about how one
17 draws distinction between tra -- between different
18 types of transmission and why, then, it might be
19 appropriate to treat it differently in the -- in the
20 context of cost-of-service.
21 The purpose of this slide was really to
22 distinguish between networked transmission, which is
23 the spider web, if you will, generation outlet.
24 Northern collector system is -- is how I view that.
25 And, also, you know, there has been some discussion

about what role and purpose that radial transmission serves. And so this is attempting to -- to demonstrate that.

(BRIEF PAUSE)

MS. KELLY DERKSEN: We talked a little bit in some of our IRs, as well, about load following issues. And I had a -- a number of questions internally about, you know, what that really means. I'm not the technical expert by any means on this. Dr. Swatek, Mr. Cormie will have to help me out on this.

But, you know, this picture does a -- a nice job, also, of showing how that a customer's load at any point on our system provides instantaneously changes in flows in the entire -- in the entire network of transmission. And we look at that as sort of a key clue, if you will, in terms of cost allocation and distinction drawn in terms of how we allocate that -- that kind of cost.

(BRIEF PAUSE)

MS. KELLY DERKSEN: It's just some

1 summary information here in terms of PCOSS14. We
2 talked about the $1.1 billion of annualized
3 generation-related costs that underpin that -- that
4 cost-of-service study. We talked a little bit about
5 how that investment is going to be significantly
6 increasing in the upnumb -- upcoming number of years
7 and in terms of the additional of Keeyask and Bipole.
8 I didn't really want to say too much
9 about this particular slide other than I forgot to
10 qualify it. You'll see that there's a -- a little
11 asterisk there be -- beside the column on the right-
12 hand side, twenty (20), twenty-one (21), and twenty-
13 two (22). And the -- the point that was missed that
14 was critical, from -- from my perspective, that's not
15 noted on the slide is that we've made some really
16 oversimplifying assumptions in terms of -- of driving
17 out that allocation of upcoming investment. We
18 haven't, for example, accounted for any changes in --
19 in distribution costs that we expect and are -- are
20 anticipating and planning for. So you'll see that
21 distribution plant investment is declining over that
22 period, for -- for example.
23 And I -- it -- it may well be that in
24 the context of the rest of the functions that it does
25 indeed decline because of the heavy influence of

generation investment that's up -- upcoming. But if it's going to decline to that extent, I -- I'm not certain. And, additionally, we haven't accounted for the fact that we know that there will be new energy coming out of Keeyask. And with that new energy is anticipated revenue. And that revenue and that energy has not been captured in here either.

(BRIEF PAUSE)

MS. KELLY DERKSEN: I think there are probably three (3) key issues with respect to generation that we will talk about in this process. Number 1 is how -- how we handle Bipole III, and I -- I suppose by extension then Bipoles I and Bipoles II, Dorsey and Riel, and also our weighted energy allocator. In terms of Bipole III, Manitoba Hydro we view it from a function perspective from how that investment, that asset, is intended to be used. Once it does come online is really no different than Bipoles I and II.

So I think that's probably the key -- the -- the key message coming out of that from a cost allocation purpose perspective. Then it makes sense that you would treat it no differently than Bipoles I

1 and II. The role of that facility, or those
2 facilities, is to move energy from our generators up
3 north eighty-seven hundred and sixty (8,760) hours of
4 the year, and it doesn't just serve energy
5 requirements at peak periods.
6
7 (BRIEF PAUSE)
8
9 MS. KELLY DERKSEN: I liked the -- the
10 spider web slide, also, from the perspective, I think.
11 Dr. Swa -- Swatek taught me this. A Bipole is -- is
12 really like a -- I think he called it to me a 'bullet
13 pipeline' sending energy from -- from the north to the
14 south. And functionally then it's different than the
15 rest of our transmission investment. We'll talk a lot
16 about that today and tomorrow.
17
18 (BRIEF PAUSE)
19
20 MS. KELLY DERKSEN: We've made a
21 change in how we handle Dorsey. The impact wasn't
22 particularly material because it's a fairly old asset,
23 fairly depreciated. So its net book value isn't
24 significant. It does have more significant
25 consequences, though, when we have -- when we bring

1 Riel on line. We previously functionalized Dorsey,
2 and we're talking about the DC facilities here, as
3 opposed the switch or the AC component of that
4 facility. We pre -- previously functionalized the
5 entire facility as a hundred percent transmission.
6 Based on the work that we have done
7 with our consultant Christiansen, they have provided
8 us advice that we might want to consider that more
9 fully, in terms of the functionality of the DC
10 component of Dorsey. I also recollect that in Order
11 7/03 there was direction from the Regulator in that
12 order to consider further how we handle Dorsey in the
13 context of cost of service. And I -- I guess the
14 upshot of it -- it all is that we have done that. We
15 have made a change in how we handle Dorsey, and we
16 intend to apply that treatment also to Riel. And
17 we've functionalized the DC components of -- of that
18 facility, and upcoming Riel is 100 percent generation.
19 And I think one of the -- at least in
20 my -- my mind, the engineers can talk much better from
21 a technical operating perspective but from my mind the
22 -- the key distinction in -- in terms of the change in
23 treatment for Dorsey is to recognize the role that it
24 plays, and the -- you know, the fact that it's
25 attached directly to the bipoles. And it needs to

1 convert the energy that -- that goes through the
2 bipoles in -- in order to make it usable on the AC
3 portion of our transmission network.
4 And we view that as a superior approach
5 in terms of cost causation compared to what we
6 previously did which was to recognize what that
7 facility replaces, if -- if I can generally
8 characterize what our past perspective of that
9 facility was.
10
11 (BRIEF PAUSE)
12
13 MS. KELLY DERKSEN: So the key issues
14 with respect to generation generally is the generator
15 provides two (2) functions instantaneously and
16 inseparable to customers. Number one (1) is demand.
17 Second is energy. Customer use -- customer classes
18 use demand and energy different, and it's important
19 for cost allocation purposes that we recognize that
20 distinction. Therefore, the question that -- you
21 know, the -- the million-dollar question is: How do
22 you draw that distinction? Where is that line drawn?
23 And we've said that because we have
24 large hydraulic facilities, those hydraulic facilities
25 provide energy for much of the year. And -- and the

1 argument tends to be about how influential providing
2 energy at all times of the year should be in terms of
3 -- of cost allocation.
4 I read recently -- someone described it
5 this way, and -- and I liked it. And -- and that is
6 once you build a hydraulic generating station your --
7 your energy price is basically locked for let's say
8 almost the life of that asset, which is -- could be
9 fifty (50) or sixty (60) or seventy (70) years. And
10 so utilities tend to invest more heavily in those
11 large fixed types of assets in order to minimize fuel
12 costs. Almost -- almost like a fuel substitution type
13 of issue.
14 And so that really has driven us a lot
15 in terms of the cost allocation methodology that
16 classifies generation 100 percent energy. But
17 allocates on the basis of -- of weighted energy, which
18 we have talked about the fact that there is a demand
19 component in -- in doing that.
20
21 (BRIEF PAUSE)
22
23 MS. KELLY DERKSEN: Through the work
24 with our consultants, they have suggested that we
25 might -- because of the changes in -- in the external

1 market to which Manitoba Hydro significantly part --
2 participates, that capacity may no longer be
3 adequately reflected in energy price with the
4 evolution of a capacity market, and that we should
5 consider an adder of capacity. And so that will be a
6 significant issue we talk about.
7 Number 1 is it -- is it appropriate to
8 do that? And number 2, how might you -- you go about
9 and -- and do that? You know, the folks at MIPUG have
10 sort of -- have questioned if the outcome of adding a
11 capacity adder is intuitively what one would expect,
12 and we'll talk more about that.
13 This is -- the weighted energy
14 allocator has been used in -- at Manitoba Hydro for a
15 decade. We talked about it last at the 2006 Cost-of-
16 Service Methodology Review, and it was approved in
17 Order 117/06.
18 We went that route at that time at the
19 advice of our consultant at the time of NERA, and we
20 have a new consultant that we've been working with for
21 a number of years, Christensen, who have provided the
22 same advice that a weighted energy allocator is a
23 superior allocator in terms of cost depiction for the
24 utility that Manitoba Hydro owns and operates.
25 THE FACILITATOR: Kelly, I note that

1 the time line for the general introduction is up.
2 Were you combining the two (2) for the generation and
3 the general one together?
4 MS. KELLY DERKSEN: Yeah. You know,
5 that was really our -- our motivation here is that we
6 would --
7 THE FACILITATOR: Right.
8 MS. KELLY DERKSEN: -- we weren't
9 certain where that was going to start and stop, so --
10 THE FACILITATOR: Well, that sounds
11 like a good idea. But anyways, ten (10) more minutes.
12 MS. KELLY DERKSEN: I think we'll get
13 to -- to exports. I'll talk briefly about slide 27.
14 There's sort of some -- if I could dummy it down in
15 terms of the -- our submission materials and pull out
16 what the key themes are from both our submission
17 materials as well as the IRs.
18 There are four (4) in -- in my mind.
19 Number 1 is that we build to serve Manitoba need.
20 Number 2 is that we've created an export class out of
21 recognition that exports use the temporary surplus
22 energy that is not needed currently with respect to
23 serving Manitoba load.
24 Simplicity and fairness was a key
25 objective of ours. And also, the heart of the issue

is that it doesn't matter what you assign in terms of cost to the export class. It doesn't change export revenue. It impacts domestic cost responsibility. It shifts costs between all of the customer classes. And so that's the key -- the key issue that needs to be well understood. It's not about the value of exports.

MR. DAVID CORMIE: Good morning. I'm David Cormie, division manager of power sales and operations at Manitoba Hydro. I'm responsible for Manitoba Hydro's activities in the export market and for the production, planning, and scheduling of water and energy resources throughout the year.

I wanted just to talk a little bit about -- about exports and how they -- how they arise in our power system. And I thought a good way to start was just to look at a chart of -- of Manitoba load and compare that to the capability of the power system.

And so this first chart here shows for the year 2014 the daily pattern of energy use in the -- in the province, starting on the 1st of April and how it declines through the spring, and then you have the summer period of -- of relatively constant load around -- averaging around 2,400 megawatts.

Then through the fall it picks up as we

1 enter into the heating season and there's more
2 lighting demand. And you can see that, on average,
3 there's about 1,500 megawatts of additional load in
4 the winter than compared to the -- to the summer.
5 And that seasonal load addition creates
6 the -- the winter peak for the power system. And --
7 and that winter peak usually occurs seven, eight
8 o'clock in the morning, cold January morning. It's
9 dark out. And in this -- in this chart, that peak
10 demand occurred in the middle of December at around
11 4,800 megawatts.
12 And so -- so the -- and then I -- and
13 then I think on an -- on an annual basis the amount of
14 energy that is needed to serve the load in all hours
15 is probably around 24 terawatt hours. So if you added
16 up all the -- the daily energy demand it gets -- you
17 get ab -- approximately that amount.
18 So in order to serve the -- that load
19 in the winter and -- we've installed facilities in a -
20 - shown on here a bar at around 5,400 megawatts, which
21 includes all the hydro capacity, and -- and there's
22 250 megawatts of wind energy in there as well. And
23 then on top of that we have about 450 megawatts of --
24 of thermal resources at Brandon and Selkirk. And on
25 top of that in the wintertime we have over 600

1 megawatts of -- of capacity imports available under
2 contract with Amer -- American utilities.
3 So if you have a peak load of around
4 4,800 megawatts, we have a requirement that not only
5 do we meet that peak, but we meet it reliably. And so
6 we have a -- a 12 percent reserve requirement above
7 the winter peak. And in that case it adds around 600
8 and some megawatts to the winter peak. So you'd -- to
9 serve the need in that year you have to have at least
10 5,500 -- around 55 or 5,600 megawatts available. But
11 the hydro system has -- doesn't have that by itself.
12 It -- it -- you need to have additional capacity
13 resources above that to supply it dependably. And you
14 can see how, once you have the reserve requirement, it
15 exceeds the available capacity that's available on a
16 day to day basis from the hydro -- from the hydro
17 system.
18 In the winter the load is -- you know,
19 on a cold winter day it's relatively constant. You
20 have high daily load factors some -- somewhere in the
21 93 percent range. In this chart you can see you've
22 got a -- a 4,800 megawatt peak. The minimum load's
23 around four thousand (4,000), so constant high demand.
24 And in -- in all those hours it's the hydro system
25 that is supplying the energy to those -- to -- to that

1 load under normal water conditions.
2 In the summertime you can see the --
3 the weekly pattern peaks around 3,000 megawatts,
4 averages around 2,400 megawatts. And -- and so you
5 can see because we've installed hydro and wind capac -
6 - and thermal capacity to meet the winter peak,
7 there's -- there's, you know, about 1,500 megawatts
8 more hydro available for export. And if there's
9 enough water available that surplus capacity will be
10 used to -- to generate income from the sale of surplus
11 energy.
12 This chart here compares that Manitoba
13 load demand to total generation. And total generation
14 is the generation needed to serve the Manitoba load,
15 plus the generation that is used to serve the export
16 load. And what you'll notice is that total generation
17 is generally relatively constant summer and winter.
18 There's a -- we -- we max out in the summer season
19 around 44, 4,500 megawatts. And in the winter it's
20 around 46, 4,700 megawatts. The difference is that we
21 have some outages in the summers that makes those
22 hydro units unavailable. But generally the hydro
23 capacity that's available for dispatch on a day to day
24 basis is around that number 40, 47, 4,800 megawatts.
25 And so you can see in all -- almost --

1 in -- under normal conditions that the Manitoba load
2 is served completely from -- from the hydro system.
3 But there are times of the year when there's large
4 surpluses available, and that's the surplus that we
5 take -- take to the market. In the wintertime there's
6 very little surplus available and -- because if you
7 have 4,800 megawatts of hydro and you have 40
8 megawatts of Manitoba load, you're -- you're not --
9 you're not a big exporter.
10 And this -- and this chart here shows
11 on -- on December the 12 -- on December the 11th under
12 normal flow conditions that the vast majority of the
13 hydro energy -- and this is a chart that just shows
14 hourly demands for -- for the day. The blue area is
15 the hydro generation. The vast majority of the hydro
16 is used to serve the Manitoba load. And there's a --
17 there's a little bit of surplus hydro available to
18 serve -- serve the export market.
19 And so we take it to the export market
20 because our marginal production cost is very low.
21 It's in the order of four dollars ($4) -- four (4) --
22 four dollars ($4) a megawatt hour. Market prices are
23 generally multiples of that, you know, in the twenty
24 (20) to thirty (30) to forty dollar ($40) range. And
25 so we will sell the -- the surplus energy into the

1 market. We won't sell the -- the thermal energy or
2 the -- or we won't be importing because we're -- if
3 we're exporting we're not going to be importing. But
4 we won't sell the thermal energy. It's because our --
5 our gas and -- gas units are not -- are not -- not in
6 merit. They're not economically attractive in the
7 market.
8 If you compare that to a -- a drought
9 scenario, what happens in a drought, we just have
10 insufficient energy, so there is no surplus, and we
11 have to import continuously and run our thermal energy
12 continuously as a -- to back up the energy that would
13 normally be produced from the hydro system. So there
14 are no exports occurring. The energy that's coming
15 from our thermal and our imports is used to serve
16 Manitoba load, and it's used to serve -- to back up
17 the -- back up the hydro system.
18 So in summary, our load is met in every
19 hour under all conditions normally with -- with the --
20 with the hydro resources that we have. The other
21 resources that we have are to provide a backstop. The
22 -- in -- from a capacity perspective, our imports and
23 our thermal resources help us meet our reserve
24 requirements in case there's an emergency. And if we
25 have a drought, then our thermal resources and import

1 resources are used to replace the energy that would
2 normally come off the hydro system. So they're held
3 in reserve for those events.
4 Yeah, I think that's -- that's all I
5 wanted to say now.
6 MS. KELLY DERKSEN: Excuse me, I'll
7 just have to go very quickly a couple of -- through a
8 couple of key points.
9 In terms of the creation of the export
10 class, in -- two (2) or three (3) key points would be,
11 number 1, we have done that essentially out of -- from
12 a fairness and equity perspective. It's not based on
13 engineering or science. It's very difficult to
14 identify fixed costs, if not possible, related to
15 exports.
16 So we've taken the -- the simplistic
17 approach to say approximately a half of our export
18 sales will be treated on an equivalent basis to our
19 domestic customers, notwithstanding the lesser level
20 of service that those export customers receive that
21 we've talked about in some of our materials in
22 comparison to a domestic customer. It is -- is an
23 issue of treating the -- that group of customers
24 notionally on an -- an equitable same-footing
25 perspective as a domestic customer.

1 (BRIEF PAUSE)

2

3 THE FACILITATOR: I think the time is
4 up anyways, Kelly. I mean, you've covered off the --
5 the export, as well.

6

7 (BRIEF PAUSE)

8

9 THE FACILITATOR: Yeah. You good?
10 Good. Thank you very much. Thanks for keeping on
11 time, as well. So we're moving on now to the -- the
12 first of the questions here, and it's -- MIPUG's up.
13 Hopefully Patrick's up.

14

15 QUESTIONS BY MIPUG:
16 MR. ANTOINE HACAULT: Yes, it will be
17 Patrick. Antoine Hacault, for the record. We'll
18 start by saying although there's an hour allocated to
19 MIPUG, if there's natural follow-up questions from
20 other consultants, in the spirit of cooperation, we
21 would invite other consultants to do that. Hopefully
22 it works out even though we're trying to put some
23 structure to this, and time frames for each
24 consultant.
25 There's some other things I'd just

1 bring up very briefly. Some issues like Bipole III
2 have been functionalized as generation, but they're
3 transmission lines. So we're not too sure exactly how
4 that' going to morph the discussions during the next
5 two (2) days with -- which deal with generation and
6 transmission.
7 And we hope to focus more on the
8 principles and particular examples, and getting into
9 what we would consider as a presentation of our
10 points. That would be left for a later day. So just
11 because we don't ask questions or don't present
12 things, that's not because they're not important to
13 us.
14 And with that kind of general
15 introduction, I'll leave the heavy lifting to Patrick
16 Bowman.
17 MR. PATRICK BOWMAN: So as -- as
18 Antoine noted, we're -- our intent is to try to focus
19 at some principle levels and clarify things that were
20 in the Information Requests or in the original filing
21 that we think there's still some benefit to having
22 clarified on the record, not necessarily trying to
23 deal with -- with cross-exam or the -- or the -- the
24 precise numbers, and it's just, I guess, to confirm
25 that.

1 We've got PCOSS14 and PCOSS14 amended
2 as sort of the two (2) most recent examples filed on
3 the record. But just to make sure that it's clear,
4 those are both based on IFF-12, correct?
5 MS. KELLY DERKSEN: Yeah.
6 MR. PATRICK BOWMAN: Okay. And -- and
7 I -- but with -- with some adjustments. It's not
8 exactly IFF-12, as I understand it. There are some
9 things -- IFF-12 didn't include a -- a Bipole deferral
10 account, but the -- the implic -- in -- in PCOSS14,
11 there is a small adjustment to say, There's part of
12 this revenue we won't include, because it's going to a
13 deferral account. Is that --
14 MS. KELLY DERKSEN: You -- you're
15 right. And we -- we prepared PCOSS14 where we were in
16 the process of finalizing it when the board order was
17 issued which contemplated -- provided direction with
18 respect to the Bipole account, so we made some
19 adjustments to what the revenue -- what the revenue
20 requirement that underpinned that financial forecast
21 was to accommodate that.
22 MR. PATRICK BOWMAN: Okay. Right. So
23 if we say in terms of numbers, there's a lot of water
24 under the bridge between IFF-12 and IFF-16 or
25 whatever, that -- that this isn't necessary the -- the

1 latest and the greatest. This is an -- an example of
2 a snapshot in time that we can use to debate some
3 principles and methods, not necessarily to say, This
4 is -- this is the best depiction of Hydro's costs
5 today or something.
6 Is that fair?
7 MS. KELLY DERKSEN: I -- I think
8 generally that's fair. The -- the qualifier that I
9 would add is, if you're looking at talking about
10 concepts, it's -- it's a pretty good basis to do that.
11 You're not looking at understanding why costs are --
12 are changing in terms of revenue requirement as much
13 as you're trying to understand what a particular
14 methodology would do in terms of an outcome, for
15 example.
16 MR. PATRICK BOWMAN: Right. And I --
17 I think we're -- we're -- just to understand, but we -
18 - we are in agreement with that part. Now, because
19 it's based on IFF-12 and it's -- it's representing the
20 2013/'14 fiscal year --
21 MS. KELLY DERKSEN: That's right, yes.
22 MR. PATRICK BOWMAN: -- which is this
23 -- this sort of what we call the second year of the --
24 of IFF-12?
25 MS. KELLY DERKSEN: Yes.

1 MR. PATRICK BOWMAN: And -- and that's
2 designed -- that second year of the IFF is designed by
3 looking at your water conditions as they existed at a
4 particular point in time, which is referenced in IFF-
5 12, carried forward for a set of inflows during the
6 2013/'14 years, a forecast set of inflows, and then
7 further carried forward for -- of -- of some median
8 inflows through '13/'14.
9 In the IFF, it's not until we get into
10 '14/'15 we'd be talking about the mean of all
11 financial experience. Is that fair?
12 MS. KELLY DERKSEN: I -- I think
13 that's true. We look at a set of what -- we have some
14 understanding at the time that an IFF is prepared in -
15 - in terms of water conditions that are reflected in
16 the IFF and applied to median conditions for the test
17 year that underpins a cost-of-service study.
18 MR. PATRICK BOWMAN: And -- and this
19 is your -- when you run a PCOSS, you're normally going
20 to have that -- PCOSS14, the original version, was the
21 normal process of -- of lag and -- and cycling through
22 of an IFF based on -- on a -- a given year, fiscal
23 year, looking to the second year and carrying that
24 into a -- a PCOSS that -- that matches with it.
25 Is that -- is that fair or was this an

1 outlier?

2 MS. KELLY DERKSEN: It -- it wasn't an

3 outlier. It was how we typically would prepare a

4 cost-of-service study.

5 MR. PATRICK BOWMAN: So I -- I just

6 want to move this forward because we want to talk

7 about the -- the principles associated with it. But

8 that means that PCOSS14 is based on a fiscal year that

9 is designed with some projections of inflows or some -

10 - considering some median inflows, but with a starting

11 point that's based on a given point in time, somewhere

12 in the middle of the -- of the '12/'13 year. That --

13 I -- I can't remember the month, but it's given wat --

14 it starts with a given water reservoir levels.

15 Is that fair?

16 MS. KELLY DERKSEN: I -- I think

17 that's fair, yes.

18 MR. PATRICK BOWMAN: And so if you do

19 a -- a PCOSS in a -- for a different year, if you

20 would look -- look back to PCOSS12, or PCOSS11 or --

21 or -- I don't think there was a 12, but look to 11, 9,

22 each of those would be done similarly for an IFF

23 looking at a scenario starting with the one (1) given

24 water flow and a projection of inflows and a -- and a

25 median of -- of inflows eventually for the second

1 year.

2 MS. KELLY DERKSEN: Right. There

3 would be some changes from cost-of-service study to

4 cost-of-service study.

5 MR. PATRICK BOWMAN: Yeah.

6 MS. KELLY DERKSEN: Even if you had

7 median flow conditions constant in each of those

8 studies, because of the fact that some level of water

9 conditions is considered in the preparation of -- of

10 the -- the financial forecast.

11 MR. PATRICK BOWMAN: Right. So -- and

12 -- and I go to there because I just want to clarify.

13 Although you've run a PCOSS14 based on a -- an -- a --

14 a factual water condition that existed sometime in --

15 in '12, '13, and if you'd run the PCOSS05, you would

16 have looked at a factual condition in -- sometime in

17 2004, which was during a drought.

18 If you run it another year, you might

19 be using a factual starting water condition that's

20 during a -- a high water level. Each of those will

21 flow through to some extent to the PCOSS, even though

22 the median inflow is carried the -- the fiscal year in

23 question, the median inflows.

24 There's -- there's -- I -- I can't pull

25 up the IR at the moment, but there was references in

1 some IRs.

2 MS. KELLY DERKSEN: Some?

3 MR. PATRICK BOWMAN: You have to be

4 careful comparing sometimes the PCOSSes, because they

5 may have different starting water in one (1) version

6 versus starting water in another.

7 MS. KELLY DERKSEN: You're right about

8 that, yes.

9 MR. PATRICK BOWMAN: And I just want

10 to, then, get to the point that you're -- you're not,

11 then, running a cost-of-service study that's meant to

12 show some -- some hybrid of all the ways the system

13 could be ued -- used. It's not some average of

14 eighty-six (86) PCOSS runs and pull the average

15 numbers out. It is actually one (1) water-flow

16 scenario effectively underlying that PCOSS.

17 MS. KELLY DERKSEN: I -- I think --

18 I'm not quite sure that I'm there. Median flow

19 conditions are intended to consider, perhaps not as --

20 not perfectly consider, but a range of -- of

21 circumstances. We don't prepare a cost-of-service

22 study for eighty (80) -- eighty-six (86) different

23 cost-of-service studies, if that's the question.

24 We don't, but median conditions that

25 underpin the -- the financial forecast and are used,

1 then, for cost-of-service purposes, the purpose of
2 doing that is to reflect some -- some range of -- of
3 conditions.
4 MR. PATRICK BOWMAN: So when you look
5 forward to -- like if we look in the IFF and those
6 later years in the IFF, the -- the -- after the first
7 two (2) years, you'll have a -- a value in there for
8 how much coal you might use from Brandon.
9 And it's an average of all sorts of
10 different water flow scenarios. Some might use a lot
11 of coal, most use almost no coal, and -- and it
12 averages those to come up with an IFF scenario.
13 But when we look to the PCOSS, what
14 we're actually going to see is one (1) water-flow
15 scenario based on very likely using almost no coal,
16 because under that median inflow conditions, you
17 wouldn't end up with very much coal running.
18 Is -- is that -- is that fair?
19 MR. DAVID CORMIE: Yes, Mr. Bowman.
20 We're -- we're trying to represent with the median
21 what normally would happen. And it's not normal for
22 us to burn any coal at all.
23 MR. PATRICK BOWMAN: Right.
24 MR. DAVID CORMIE: You can go from
25 probably the 2 percent outflow to the 100 percent

1 outflow, and there's no -- there's no coal generation.
2 So when you bring in the minimum flow year with
3 thermal generation, you could average it out, in --
4 include that in -- in the PCOSS. But we don't,
5 because that's not normal.
6 So what we're trying to reflect in the
7 test year, in the year of the PCOSS, is what's -- what
8 normally we'd expect. And normally we would serve all
9 our loads with -- with the hydro, and normally there
10 would be some off-peak imports in the winter. And,
11 you know, that's kind of the normal operation that --
12 that you would expect.
13 The use of our gas resources and our
14 thermal resour -- and -- and our coal resources is not
15 normal. It's -- they're -- they're a backstop for
16 essentially, you know, the worst case. But it's --
17 you know, they're not -- they're not built into the
18 PCOSS.
19 MR. PATRICK BOWMAN: So I -- I'm going
20 to go that, because we -- we -- it -- it uses the
21 words -- for example, in your slide, you say that the
22 purpose is to determine the class responsibility.
23 Elsewhere, we talk about causation, which isn't, you
24 know, perhaps a synonym, perhaps not, but it's used
25 throughout. And then we talk about different things

1 like you were trying to track who uses the asset.
2 But in something like a PCOSS14,
3 actually no one's using Brandon coal in a sense of
4 receiving kilowatt hours from it. They're using it in
5 a sense of it exists for the purposes if this flow
6 condition didn't arise. But it's not necessarily used
7 -- you can't just look at where the kilowatt goes to
8 know what -- what that asset is -- is for.
9 MR. DAVID CORMIE: No, and -- and I
10 think a good analogy for our -- our thermal resources
11 is -- is fire insurance. They -- those resources, you
12 -- are like buying fire insurance. So we pay the
13 annual premium of keeping those facilities available.
14 We don't expect that there's going to be a fire, so
15 you never actually call on your insurance, but you pay
16 the premium to keep that -- that on standby in case it
17 -- it happens.
18 And -- and that's what -- that's --
19 that's what the role of -- of the thermal resources.
20 They're there for -- to maintain reliability in case
21 we have a problem on our DC system. We have low
22 water. We have a supply of capacity and energy that
23 could be called on, but it's not likely that it will
24 be called on.
25 MR. PATRICK BOWMAN: So as a -- as a

1 practical test of causation you -- you mentioned
2 balancing factors but one of the factors might be,
3 What is this asset used for? But use may not be
4 tracking kilowatt hours. It would be tracking, Why do
5 we have it in the first place?
6 MR. DAVID CORMIE: Right. And -- and
7 we have a requirement to maintain reserves, and to
8 maintain a level of reliability. And that's why those
9 -- those resources are -- exist. It's -- it's to
10 provide not just sometimes we're going to have power
11 but we're going to have power all the time. It's the
12 guaranteed supply. That's -- that's what -- that's
13 what gives us the -- the guarantee.
14 MS. KELLY DERKSEN: If -- if I could
15 bring this back to cost of service. I think where
16 you're going, Mr. -- Mr. Bowman, is, you know, what do
17 you -- how do you -- what weight do you give to the
18 reason why you invest in an asset in terms of cost
19 causation, and clues or information as to who should
20 be responsible for the cost of that investment
21 compared to on a year to year basis how operationally
22 that you intend to use that -- that resource.
23 Sometimes those thing are not -- not the same.
24 We put assets in place at one point in
25 time. How we use those assets change -- can change

1 over time. Thermal is a good example of that. And so
2 the question is, What weight do you give on why you
3 invest in an asset, and who should bear responsibility
4 for the cost versus operationally what -- how do you
5 factor in who -- who is responsible for that cost from
6 -- form a year to year basis?
7 Median flow conditions aren't perfectly
8 suited to considering the wide range of circumstances,
9 which is where you -- you started the questioning, to
10 those kinds of issues. But it -- it's a proxy -- it's
11 approximate. We have been talking a little -- a
12 little bit internally about moving away from the use
13 of median conditions purposes, the financial forecast,
14 and therefore then cost of service in the -- the rate
15 setting period.
16 But -- and -- and those are some of the
17 discussions but, you know, median broadly at least is
18 there to represent the variety of conditions, and --
19 and how you would serve your load under those kinds of
20 conditions from -- from a financial perspective.
21 MR. PATRICK BOWMAN: And do you -- I
22 don't know if you -- I -- I appreciate it's a balance
23 of considerations. I just want to understand Manitoba
24 Hydro's rationale when you have a -- the white board
25 and you scribble up the assets, and you think about

1 how you're going to use them.

2 Do you have a priority, a balancing of

3 -- if -- if asset 'X' is -- is built under this

4 business case it's change -- it's -- it's -- in this

5 flow condition it's used for this other purpose which

6 is different than what it was necessarily built for

7 because of the insurance factor, or if we have a

8 change in factors like -- like Brandon Coal not being

9 allowed to be used for export.

10 How -- how are those -- are those

11 balanced? What is -- what is the priority driver when

12 you're making those decisions about where -- where you

13 guys want to put -- put forward your -- your proposed

14 methods?

15 MS. KELLY DERKSEN: I'm not sure that

16 I can be completely responsive to that. I think it's

17 dependent on, you know, the resource that -- that

18 you're talking about. We tend to pool, for example,

19 our generation resources. We don't tend to look at

20 them on an asset by asset basis. And -- and the

21 reason for that is a good one, in my mind, and that

22 is, you know, we're predominately hydraulic.

23 They generally serve the same role --

24 function and role. How the -- what -- the reason we

25 invest versus how we operate them are largely one and

1 the same. The -- there can be instances like thermal,
2 for example, whose role can change over time. And
3 from a cost allocation perspective, it would be
4 appropriate at some point if the role of that facility
5 does change to incorporate how it is used today as
6 opposed to how historically we -- or why historically
7 we may have invested in that. It makes sense to do
8 that. It -- it doesn't seem to me to be logical that
9 you would continue with a cost allocation methodology
10 based on an investment made -- an asset put in place
11 to serve a function at one (1) point in time that has
12 changed.
13 MR. PATRICK BOWMAN: And that -- I
14 think that Brandon Coal is probably the best example,
15 where it had been -- when we sat here in '06 it didn't
16 have those restrictions as I recall. We talked about
17 it having a multiple function. Now it's -- it's got
18 restrictions, and as a result, up to this most recent,
19 you guys said -- or this -- this should really be a
20 domestic asset because it's not even allowed to be
21 used in any of these circumstances whatsoever to ever
22 support an export sale. And so we -- we talked about
23 it -- changing to domestic, regardless of why it was
24 built in the '50s or whatever it was.
25 MS. KELLY DERKSEN: Well, the

1 rationale for the change in the treatment of coal and
2 PCOSS14 amended wasn't because we don't believe that
3 that investment today, that resource today, is only
4 intended today to serve domestic load. But it was
5 more from the perspective of, I understand that there
6 could be a perspective that -- and it's not an
7 unreasonable one (1) that you can't stream electrons.
8 So if we were in an emergency circumstance, and that
9 facility had to be used to support power in the
10 province, you know, I understand the perspective that
11 you can't stream electrons. You don't know where that
12 energy necessarily is going.
13 And so from a simplicity perspective, I
14 didn't think it was reasonable that we would continue
15 down the path to try and debate what the role of that
16 facility is at some point in time under some set of
17 circumstances, put it all in the pool, and let's share
18 the -- the cost responsibility between domestic and
19 exports. And it wasn't because we thought that that
20 facility, from a technical perspective, was being used
21 differently. Yeah, I hope...
22 MR. PATRICK BOWMAN: Well, from
23 PCOSS10 to PCOSS14 it was directly to domestic. And
24 it was changed that way as a result of the
25 legislation, which said this is only for domestic.

1 Is that part -- part fairly...
2 MS. KELLY DERKSEN: That part is fair.
3 And, like I said, we sat back after some of the
4 discussions we had at stakeholder meetings and we
5 thought it appropriate that for simplicity, we don't -
6 - we want to, as best we can, not try to go down this
7 path and place too fine a point on where cost
8 responsibility lies for exports. Because it's very
9 difficult to do that. You get into a circular debate.
10 You're left at times with circumstances where a cost
11 becomes unallocatable, which is just silly, because
12 it's not used for domestic purposes in this case, and
13 it's not used for exports in this case. And so you're
14 left in a situation where you can't allocate the cost.
15 Throw it in, share it between dependable and domestic,
16 and we -- we think that is the most fair way of -- of
17 treating it.
18 MR. PATRICK BOWMAN: So I -- I would
19 agree that use is a more limited test and sometimes
20 can lead you to funny outcomes, where you say, Wait,
21 what -- who's using it under the scenario that's here?
22 But I can't imagine an unallocatable cost if you're
23 not focussing on use, but you're focussing on what --
24 what -- why do we have it in the first place? What
25 did we incur the cost for? Do you un -- like, I'm

1 trying to imagine anything that would fit in that.
2 MS. KELLY DERKSEN: The coal facility
3 is -- is a good example of that. We were in
4 discussions previously before the -- before the
5 Regulator. And that is this legislation was in place.
6 We viewed that legislation to say, Manitoba Hydro, you
7 can't use those resources for export purposes. You
8 can only use them to serve in mer -- emergency
9 circumstances to support your domestic load.
10 And then it became a debate of, Well,
11 define an emergency circumstance. And then it became
12 a debate of, Well, you can't stream energy. And in
13 other cases it was that, that is the marginal
14 resource. It's only there to provide energy for
15 exports. And so you're left with a, well, if it can't
16 go to exports from the company's perspective, and
17 others' perspective was it ought not to be assigned to
18 domestics, what do you with it. And that's the debate
19 that we are trying -- trying to avoid.
20 If you get into the circular argument
21 you'll never get out of it and you will end in a
22 circumstance where you can't make a decision. So
23 that's why we've gone the PCOSS14 amended route to say
24 cool your resources, and we will share them equally
25 amongst dependable firm exports and domestic

1 customers.

2 MR. DAVID CORMIE: So, Mr. Bowman, the

3 other thing that changed since two thou -- since 2005

4 is that we can now financially settle almost all our

5 export obligations, and so there's no reason that we

6 would run thermal generation in Manitoba to serve an

7 export market. The -- it's -- it's always going to be

8 cheaper to go to the market and settle at market

9 prices rather than to -- to use -- use thermal

10 generation in Manitoba.

11 So, you know, the -- the legislation

12 prohibits the use of -- of coal for export, but

13 economics essentially makes the gas turbines only

14 there to -- to firm up the supply for -- for Manitoba.

15 So it gives us our capacity reserves and it gives us,

16 you know, two and a half terawatt hours of dependable

17 energy that will be used to serve Manitoba load once

18 you've maximized imports and settled your export

19 obligations.

20 So it -- it's -- you know, I think

21 you're right. The -- the world has changed. You

22 know, now the normal use for those facilities is --

23 for Brandon and for -- for the gas turbines is to

24 backstop Manitoba load. And so to -- you know, that's

25 -- that's what happens over time.

1 MR. PATRICK BOWMAN: If I look in your
2 -- your power resource plan there'll be some tables
3 that show the energy balance and the capacity balance
4 at the back. There'll be the same resources in both,
5 other than wind I think is not in the capacity one.
6 And in the energy one, Brandon will be listed coal as
7 well as the turbines, but Brandon coal will be backed
8 out on a bottom line before you ever say what could I
9 export.
10 MR. DAVID CORMIE: That's right.
11 MR. PATRICK BOWMAN: The turbines are
12 still in in the calculation of what could I export?
13 MR. DAVID CORMIE: Yes. And so -- and
14 that talks about that unusual one (1) in a hundred and
15 four (104) year event. And that's not -- wouldn't be
16 normal. But from a planning perspective, we have to
17 be able to show to our export customers that we have
18 the capability.
19 But when it actually comes to the
20 moment-by-moment dispatch I don't expect that they
21 will actually ever run, except for an energy emergency
22 in Manitoba. So that's why, you know, the gas
23 turbines create dependable energy that adds to the
24 supply. And you could probably enter into an export
25 contract, but they would only ever be used to serve

1 Manitoba load.

2 MR. PATRICK BOWMAN: Right. That's

3 why use is this --

4 MR. DAVID CORMIE: Yeah.

5 MR. PATRICK BOWMAN: -- tricky to area

6 to over focus on use as to determine the allocation.

7 Looking at purpose of investment would -- would get

8 you further down the road, or purpose of -- of

9 retaining the assets as opposed to retiring it, say.

10 That -- is that clear?

11 MS. KELLY DERKSEN: You'd have to look

12 at them, I -- I'd say, together, why you invest, how

13 you intend to use them, has the role of that asset

14 changed over time, do you need to accommodate that in

15 terms of how you allocate those costs.

16 I don't think that you can look at one

17 (1) or the other in isolation. You have to look at it

18 general -- generally speaking and -- in order to

19 develop a reasonable cost allocation methodology.

20 MR. PATRICK BOWMAN: Okay. I think

21 just to move on to the question about the -- all --

22 all of your generation is functionalised as

23 generation, plus these other assets you talk about are

24 fund -- you know, are -- are transmission assets in

25 their -- in their form but are functionalized as

1 generation for the purposes of cost -- cost
2 allocation.
3 That's right, you don't have any
4 generation that you're treating not -- not
5 functionalising as generation. I'm pretty sure that's
6 correct. I just want to...
7 MS. KELLY DERKSEN: If your question
8 is, do we have any generating facilities that we
9 functionalized as transmission, you're correct, we do
10 not. We don't functionalize generation as
11 transmission.
12 MR. PATRICK BOWMAN: So when we go to
13 the classification of those --
14 MS. KELLY DERKSEN: But I -- I know
15 you'll appreciate, Mr. Bowman, the issue is not as --
16 really about how you functionalize the cost. The
17 issue is about how you classify and allocate it. And
18 so that is a key -- is real -- is really the heart of
19 the issue.
20 MR. PATRICK BOWMAN: I think you'll
21 find there's a fair bit of discussion about how to
22 functionalize cost if one goes through the literature.
23 How you classify the cost though when something is
24 functionalize is generation is in regards -- your --
25 your using 100 percent marginal cost weighted energy

1 but what you've now done is you've added a small
2 premium on the peak periods to try to pick up the fact
3 that you thought there was an under representation in
4 that weighting of the role of capacity.
5 Is that -- that's the purpose of that -
6 - of doing the adder?
7 MS. KELLY DERKSEN: Can you ask me
8 that question again? I just want to make sure I've
9 got all the nuance --
10 MR. PATRICK BOWMAN: Well, I'm just
11 saying that --
12 MS. KELLY DERKSEN: -- in there
13 correct.
14 MR. PATRICK BOWMAN: -- PCOSS14 versus
15 PCOSS14 amended are otherwise based on exactly the
16 same data sets. They use a twelve (12) period
17 weighting. The twelve (12) period weighting factors
18 change. They change as a result of a Christensen
19 recommendation that Manitoba Hydro responded to that
20 said, We're doing fine on picking up the -- the energy
21 related signals but we need to pick up the capa -- a
22 capacity related component that's otherwise not fully
23 addressed in PCOSS14.
24 MS. KELLY DERKSEN: The advice of the
25 consultant was that -- is to recognize that the value

1 of capacity that is inherent in peak versus other
2 periods in the external market may no longer be
3 adequately reflected. And so we have accepted their
4 advice, and we have applied in -- in terms of the
5 submission a capacity adder to each of the peak
6 periods in the weighted energy allocator.
7 MR. PATRICK BOWMAN: Okay. I -- I'm
8 going to go to your presentation today, and there's a
9 -- slide 24 is about the weighted energy allocator.
10 And as -- as background, I was here when we developed
11 that and there was an attempt to use Hydro's long run
12 marginal cost. It became clear that that couldn't be
13 done for -- for transparency reasons, for
14 confidentiality reasons. They were based on numbers
15 people couldn't disclose so they couldn't be tested.
16 And this was a second attempt to pick up the marginal
17 cost weighting of energy was to use the -- the SEP
18 price as something practical.
19 I -- I know it won't go to this slide.
20 It says it's effectively short run marginal energy
21 costs but you say, "They're well suited to Manitoba
22 Hydro's operations." And I -- I would recall this as
23 an -- a reasonable but not the first ideal attempt at
24 trying to figure out how to best deal with Manitoba
25 Hydro's energy because it's a short run marginal cost

1 rather than the long run marginal cost which is really
2 far more relevant to the way that people think about
3 developing facilities or making investments.
4 So when you say "well suited" I hadn't
5 seen that language before. What -- what does it mean
6 -- what do you mean by "well suited?"
7 MS. KELLY DERKSEN: What that
8 statement was intended to apply -- imply is that the
9 short run marginal cost which is the -- the proxy of
10 which we use in the weighted energy allocated based on
11 SEP prices are after-the-fact prices of energy is at
12 most times the opportunity cost of serving -- of
13 serving load in -- in Mani -- in Manitoba.
14 And at times it could be based on
15 import purch -- purchases. It could be based on
16 thermal generation. But in most cases, that's the
17 opportunity cost associated with supplying Manitoba
18 load. And that was what that was intended to suggest.
19 MR. PATRICK BOWMAN: But since we're
20 allocating primarily, as you said, big fixed costs
21 that exist over longer periods of time in major --
22 largely major investments, those are made based on
23 short-term energy markets. Those are based on long-
24 term Manitoba need for energy and capacity, as well as
25 long -- long-run marginal costs or -- or impacts on

1 the market of -- of major changes to your supply
2 situation, not moment to moment opportunity markets.
3 Isn't that -- or -- or am I missing --
4 I would -- that's why I would say "well suited" seemed
5 an odd comment.
6 MS. KELLY DERKSEN: Well, if you want
7 to discuss, you know, the -- the benefits the -- and
8 the tradeoffs of long run versus short-run marginal
9 costs, we can -- we can do that. But it was intend --
10 that was what it was intended to imply.
11
12 (BRIEF PAUSE)
13
14 MR. PATRICK BOWMAN: I -- I guess what
15 -- my concern was -- seemed well suited because it had
16 always been described as basically a directionally
17 appropriate, a best estimate, a practical way of doing
18 -- of capturing something, that certain kilowatt hours
19 are more important than other kilowatt hours, but that
20 it was never going to be particularly representative
21 of the reasons for these major investments, I think,
22 because it's based on sort of short-term markets.
23 MR. MICHAEL O'SHEASY: Mr. Bowman, if
24 I can interject, I'm Mike O'Sheasy, and I'm with
25 Christensen Associates. And my colleague and I were

1 responsible for recommending that this marginal
2 capacity component be added to the allocator. And I
3 just want to see if I can help indicate why we thought
4 that was appropriate.
5 You're right. What Manitoba Hydro is
6 doing is allocating large chunks, if you will, of
7 embedded revenue requirements, and much like all
8 utilities do when they do a cost-of-service study.
9 But it's felt -- it's been felt here,
10 and I think it's a right decision, to allow the
11 marginal cost of -- that -- that is incurred here to
12 influence how those costs get divvied up or allocated
13 amongst the various rate classes. And I think it's
14 done for several wise reasons.
15 One is Manitoba Hydro has very unique
16 operating characteristics. There are obviously very
17 high, large elements of hydro, unlike most utilities.
18 And secondly, it's just a -- a good idea, as you can
19 imagine, to let customers know through allocated costs
20 what is the implication of a change in usage will have
21 on costs? And so obviously, marginal costs do that.
22 And however, it -- it's oftentimes
23 difficult to infuse marginal cost to an embedded
24 revenue requirement study. So the -- as you know, the
25 -- the methodology that's been used here at Manitoba

1 for some time has been to use a marginal cost type of
2 allocator for embedded revenue requirements. Makes
3 perfectly good sense.
4 However, as time has evolved, I think
5 that you want a marginal cost allocated that
6 represents the marginal costs that are going to be
7 imposed on the time frame in which these ultimate
8 rates will be designed.
9 The only -- the main purpose, as you
10 know, of a cost-of-service study is to do revenue
11 requirements, and ultimately rate design. So you want
12 those rate designs we believe to be reflective of the
13 -- an allocation of marginal costs that will be
14 incurred in that time period.
15 And it became apparent as the industry
16 evolved, not only here but throughout other places in
17 North America, that a simple, straight, flat, marginal
18 cost of energy was just not sufficient in our -- in
19 our minds to reflect the -- the marginal cost that is
20 being imposed in the time frame to which rates will be
21 incurred.
22 And so it's not -- we don't believe
23 it's black and white. You either use short-run
24 marginal costs or you use long-run marginal costs.
25 You use the marginal costs which you think are

1 relevant to the time period in question.
2 And so we did indeed take a perspective
3 of a short-run marginal cost of energy which we
4 thought was indeed reflective of the test period or
5 the period of time in which the rates would be
6 designed.
7 But we felt like a capacity component
8 would better reflect the actual marginal costs of the
9 time period in -- in this case. And we feel like that
10 is a wise thing to do.
11 I'm just going to give you one (1)
12 slight anecdote, and I'm not sure it's going to be
13 helpful, but when I was at Georgia Power, we developed
14 a spot-pricing rate. We called it real-time pricing,
15 and we did the exact same thing. We put in short-run
16 marginal costs of energy and we put in a capacity
17 component as we've done here based on reliability
18 costs, and it worked out very well.
19 So I hope that's helpful, but -- and
20 I'll stop there.
21 MR. PATRICK BOWMAN: Just let me
22 follow up on that. I'll have to review that answer, I
23 think, because it'll be helpful. But you said you
24 would use the short-run marginal costs. You put in a
25 capacity component based on reliability

1 considerations.

2 And this -- just -- just to clarify

3 what's done, what's -- what's done here is a capa --

4 an adder is -- is added to the weightings so that the

5 on-peak components over all four (4) seasons are

6 slightly higher. So the more important, generally,

7 the on-peak use than the -- than the off-peak use.

8 MR. MICHAEL O'SHEASY: You are correct

9 in the example that was done for this -- this

10 proceeding.

11 MR. PATRICK BOWMAN: Right. Okay. So

12 just to go -- for -- on the first issues, if someone

13 was to do an adder, why would that adder be applied to

14 on-peak, not off-peak? Presumably off-peak loads are

15 lower in capacity is less of a concern. But als --

16 but then at the same time be applied to sort of spring

17 and fall as the same as winter, when wis -- winter is

18 your -- one (1) of your major drivers and spring and

19 fall are -- are not. And we see that in the load

20 patterns. I'm curious why -- why it would apply to

21 all four (4) seasons of on-peak if you were to do

22 that.

23 Does that -- in terms of the Georgia

24 example, it might be different because they presumably

25 --

1 MR. MICHAEL O'SHEASY: Right.
2 MR. PATRICK BOWMAN: -- have a
3 different load pattern, not --
4 MR. MICHAEL O'SHEASY: Well, in -- in
5 -- and actually what we do in Georgia, is we have an
6 element of adding that capacity adder. That's a real
7 time consideration. And it can occur in the winter.
8 It can occur in the spring. Rare, rare, rare
9 occasions it can occur in the -- the fall and spring,
10 but that's extremely rare. Normally it's just a
11 winter and summer coincidence. And so I -- I say
12 that. To me it's important that you -- that it be
13 inserted when you think it's going to happen, when you
14 think it's -- it's a factor.
15 Now, for the sake of this directional
16 model that was done here, I think it was -- it was
17 done to give the viewers an idea of the directional
18 content. I'm not sure that -- that it's an absolute,
19 This is the only way to do it. This application is
20 irrefutable. I'm not sure that's the case. I think
21 this is a -- and one (1) of the reasons we have
22 workshops like this is to get better insight on what
23 is the most appropriate way to insert a capacity
24 adder. The point is we firmly believe a capacity
25 adder is appropriate whe -- the -- the on-peak periods

1 that it's inserted in, I think, is certainly a -- a
2 one (1) -- an area of reasonable discussion.
3 MR. PATRICK BOWMAN: Yeah, we -- we --
4 MS. KELLY DERKSEN: And -- and I just
5 wanted to add, there -- there's a slide -- I didn't go
6 through it. If you can first get past the hurdle,
7 which is the discussion that we will need to have, of
8 whether you view Manitoba Hydro's system as an
9 isolated one (1), or that it's more appropriate to
10 view it interconnected to a -- a market. That needs
11 to be part of the decision making because that will
12 influence also what your allocation methodology is for
13 your generation resources.
14 But secondly, we've provided some
15 materials in the presentation this morning to say, If
16 you didn't apply the adder in all periods, and only
17 applied the adder in the winter peak periods because
18 your domestic syst -- system is winter peaking, here
19 is what the -- the impacts by customer class are. And
20 I think directionally is probably more intuitive with
21 where you are coming from, Mr. Po -- Bowman, certainly
22 in terms of some of your Information Requests.
23 We haven't landed on how you -- what
24 periods that you apply the adder. It may be
25 appropriate if you conclude that you do not view your

1 system as an isolated one (1), that you give some
2 weight to the summer period. Number 1, certainly if
3 you continue down the road with an export class that
4 has costs embedded fixed cost allocation to it, it
5 makes sense to include the summer period in terms of
6 the capacity adder to recognize the peaking nature of
7 those customers or of the costs that you need to
8 allocate to that class.
9 But we haven't landed on, Do you apply
10 the -- the peaker. If you can get past number 1, that
11 you are applying, in effect, a embedded cost of
12 generation based on the de-rated value of a thermal
13 peaking plant to a marginal cost concept, a short run
14 marginal cost, what are the appropriate periods then
15 to apply it to. And I think that largely comes back
16 to how do you view your system. Do you view -- do you
17 want to view it in terms of cost allocation as an
18 isolated one or do you want to view it in the context
19 of the large interconnected market that you
20 participate?
21 MR. PATRICK BOWMAN: So there's a lot
22 in the response. I -- I know we're short on time, so
23 I just want to deal with two (2) pieces out of that.
24 One (1) is, in regards to the weighting, you said that
25 there is new information in the presentation?

1 MS. KELLY DERKSEN: I --
2 MR. PATRICK BOWMAN: I didn't -- I
3 just looked quickly and couldn't find it. If you
4 could show us where, that would be helpful at some
5 point. It doesn't...
6 MS. KELLY DERKSEN: You know what, I -
7 - I think in haste yesterday we took it out. We could
8 re -- we put it back in. It was simply a table that
9 showed what the impact of adding the capacity adder,
10 as we have discussed in our submission, to almost all
11 -- well, all of the almost two thousand 2,000 peak
12 periods that you have in a -- in a weighted energy
13 allocator verse -- versus constraining it to a winter
14 period and what the RCC effects of wo -- applying it
15 one way versus the other are.
16 MR. PATRICK BOWMAN: So that's one (1)
17 part of the consideration it'd be good to get. We --
18 I don't know if we're recording undertakings this way
19 or...
20 MR. KURT SIMONSEN: Yeah. If you want
21 an undertaking, Patrick, you should describe that now.
22 MR. PATRICK BOWMAN: It's an
23 undertaking to provide the impact of -- of the
24 scenario that was already run of applying the capacity
25 weighter -- weight -- weighting only to the winter

1 period, as -- as I understand it, winter period in the
2 -- the marginal cost energy weights and the impacts on
3 -- I will say the impacts on -- on unit costs, the
4 demand energy unit costs before -- before net export
5 revenue compared to what's in -- in the PCOSS14
6 amended and -- and PCOSS14.
7 At least we can see then how much it
8 moved from PCOSS which had no weighting to PCOSS14
9 amended, which has all periods weighted. This would
10 be a middle ground, which would be the -- the only
11 winter weighted.
12 MS. KELLY DERKSEN: Yeah, the
13 information that we had prepared is just the RCC
14 impact. That was -- that was all that we had
15 prepared. I'm not sure if we have unit cost
16 information available or not. I couldn't speak to
17 that at this moment.
18 MR. PATRICK BOWMAN: That -- I -- I
19 think that's fine. The -- the issue we have is that
20 we -- and -- and this is -- before we get to the
21 undertaking, I guess, is that these impacts are always
22 shown in terms of RCCs, which is a step removed from
23 what the cost-of-service study really needs to deal
24 with, which is what is the cost of serving the
25 customers.

1 RCCs then pulls in revenue. And you
2 have to consider net export revenue and how it's
3 credited back. And sometimes you have to include rate
4 increases like the scenario with the Bipole. You have
5 to make an assumption about how you would raise rates,
6 and then what it does.
7 If the unit costs are quite clear to
8 us, what does it do to the cents per kilowatt hour
9 cost to serve the customer, what does it do for the --
10 the cost per kilowatt to serve the customer, what does
11 it do for the customer cost to serve the customer?
12 Schedule D2 I think is -- is the one.
13 MS. KELLY DERKSEN: Mike Dust advises
14 that we have that information, either can be prepared
15 fairly quickly or we have it readily available. That
16 underpinned the -- the RCC calculation.
17 MR. PATRICK BOWMAN: It's certainly
18 part of the scenario getting to when you have to run
19 the RCC, so I assume it exists. Thanks. I'll leave
20 that there, but -- in terms of that.
21
22 --- UNDERTAKING NO. 1: Manitoba Hydro to provide
23 all PCOSS schedules
24 (including Schedule B2 &
25 B3, without net export

revenue and Schedules D1 & D2) for the scenario Hydro has already run where the marginal weighted energy "capacity adder" is added on for only the winter peak period

MR. PATRICK BOWMAN: The other comment you made is whether it's appropriate to include an export price signal in the -- in the system that's being used for domestic purposes. But, effectively, the marginal energy weighting is to say a kilowatt hour, regardless of where it comes from, is more important if it's in a winter peak hour or even winter shoulder hour say than a fall off-peak hour.

That somehow we have to pick up the fact that those kilowatt hours do not drive, do not -- are not responsible for the same type of cost impact on the system. That -- that's the point of the entire weighting in the first place, right?

MS. KELLY DERKSEN: Well, the discussion is, is should that be. And we have an intercon -- we are interconnected to a large market. We are not an isolated system. And the question is:

1 Should you develop a cost allocation methodology that
2 ignores the fact that we're interconnect. And so
3 that's -- that's the question.
4 And we've said we don't think we
5 should, number 1, because that's not the reality of
6 the system that we have. And, number 2, if you have
7 an export class, it makes sense that you would include
8 their load characteristic -- load characteristics,
9 particularly if you're treating them already on an
10 equal basis to the rest of your domestic customers for
11 dependable exports to include their load
12 characteristics in terms of allocation. So that --
13 that's the -- the discussion.
14 MR. PATRICK BOWMAN: So that -- I know
15 we don't have a lot of time left. The areas that I
16 still was hoping to deal with is a couple of short
17 pieces on what's in some of the IRs that I just want
18 to clarify.
19 The -- I wasn't quite finished with
20 this point because we've talked about the energy
21 aspect, not necessarily the capacity aspect as much,
22 and then a few questions arising from the presentation
23 that wasn't necessarily in the material that we -- we
24 prepared. I don't know the time we are considered to
25 finish this part.

1 THE FACILITATOR: I think I have you --
2 MR. PATRICK BOWMAN: Okay. So maybe
3 just to go to the presentation you did this morning to
4 -- we'll do one (1) more detail with this point. I'm
5 looking at the graphs, capacity supply versus demand,
6 29 page, I believe. Yeah, first that one.
7 And your -- and this is showing the --
8 just the domestic load.
9 MR. DAVID CORMIE: Yes, that's all.
10 MR. PATRICK BOWMAN: And when we're
11 looking at domestic load, there's a fair variability
12 in the extent to which the winter days peak, the
13 height at which they peak.
14 MR. DAVID CORMIE: Yeah. Yes.
15 MR. PATRICK BOWMAN: So when you're
16 looking at something like a CP allocator, you're
17 looking at the top fifty (50) hours, which means
18 you're picking up a lot of those higher peaks in that
19 -- in that segment.
20 That's the idea, right?
21 MS. KELLY DERKSEN: Yes, that would be
22 fair.
23 MR. PATRICK BOWMAN: And you use fifty
24 (50) -- just to be clear, when you actually go -- get
25 a cost that's allocated on demand, on coincident peak,

1 you don't use one (1) day, you use multiple hours that
2 are -- that are within the range of that highest peak?
3 MS. KELLY DERKSEN: Right, and it was
4 to address some of what you see on the slide in that,
5 on the electric system, domestically speaking, I
6 understand that years and years ago we had a one (1)
7 hour peak. And it was -- it tended to be very
8 volatile because it can change from year to year, from
9 period to period.
10 And so it's -- the -- the idea, as you
11 know, is to provide -- to capture that variability and
12 to provide some degree of -- of smoothness in terms
13 of, you know, the fact that there are multiple peaks
14 at -- at -- and they can occur at different times,
15 dependent on the time of day and dependent on the
16 season.
17 MR. PATRICK BOWMAN: So, all I'm
18 saying, even your CP allocators when you use them,
19 which they're in transmission, you're focused not on
20 just one (1) super-peak. You're focussed on some
21 reasonable range in which that could occur.
22 MS. KELLY DERKSEN: Right. That's
23 correct, yeah.
24 MR. PATRICK BOWMAN: Now, if we go to
25 the next slide, this one includes exports. And I just

1 want to clarify, this is all exports, what you would
2 call dependable as well as what you call opportunity
3 in the cost-of-service study, right?
4 MR. DAVID CORMIE: This is -- this is
5 all exports, yes.
6 MR. PATRICK BOWMAN: So -- but if we
7 were to try to draw -- this is from some actual year,
8 I presume?
9 MR. DAVID CORMIE: This is 2014.
10 MR. PATRICK BOWMAN: And if we were to
11 try to decipher those two (2), we don't have to do it,
12 and we're probably -- it'd be hard to read anyway.
13 But if the -- if it were only the -- the dependable
14 exports, the -- the winter peaks would be higher than
15 the summer peaks shown here. I think we have an IR to
16 that effect. It's about 12 percent difference, I
17 think.
18 Is that -- is that fair, or would one
19 need to see the -- the data to know that?
20 MR. DAVID CORMIE: Well, I think you
21 can see from the chart that the total generation in
22 the winter is higher than it is in the summer by
23 several hundred megawatts. And -- and that's because
24 there are unit outages in the summer which limit the
25 capacity compared to the winter.

1 But within that total exports is the
2 dependable export contracts as well as the opportunity
3 sales.
4 MR. PATRICK BOWMAN: And -- and would
5 the -- would the opportunity sales -- if you were to
6 take them out, if that green line were only the
7 dependable, would it tend to lower the line in summer
8 more than in winter?
9 MR. DAVID CORMIE: It would, yes.
10 MR. PATRICK BOWMAN: If we can flip to
11 the next graph, this is your winter supply under a
12 normal basis.
13 There's an import section in yellow.
14 Where are the diversity supply in this?
15 MR. DAVID CORMIE: There -- there --
16 those-- those imports that are shown are imports from
17 the MISO market, and they would not be done on a
18 bilateral basis under the diversity contract. It's
19 just -- it -- it's not -- it -- it's not necessary to
20 exercise your rights under the diversity when you can
21 go to the market in the off-peak and just buy energy.
22 And that's what this graph shows.
23 MR. PATRICK BOWMAN: So under the
24 diversity agreement, during this winter, you would
25 have been receiving power related to the diversity

1 agreements, no?

2 MR. DAVID CORMIE: No. The diversity

3 contracts, we have no obligation to buy. We have the

4 right to the capacity and the right to ask for energy

5 if we need it, but we have no obligation to buy any

6 energy under the diversity agreements.

7 MR. PATRICK BOWMAN: But under that

8 diversity agreement, this day you -- you weren't have

9 had anything?

10 MR. DAVID CORMIE: Yeah. The

11 diversity agreement is essentially a call option on --

12 for energy under the capacity that they reserve for

13 you. But given that the MISO market can -- can supply

14 all that, and -- and we can offer curve, it's -- it's

15 the most economical way to supply energy is through

16 the market, and not going through a particular

17 customer and say, I want to exercise my call option

18 with you. I -- I don't know whether that's a good

19 price or a bad price. Let the market determine that

20 through -- through the market mechanisms that MISO has

21 provided.

22 So the -- so what the diversity does is

23 it gives us the -- the capacity. We know if -- if the

24 market was not able to deliver, then we could go to

25 the capacity contracts and -- and demand the energy,

1 and they would supply it. But on a -- when there's no
2 emergency and it's not necessary to do that, then we
3 just let the market mechanisms work.
4 MR. PATRICK BOWMAN: So if you're
5 looking at -- I'm -- I'm sort of moving on, but if
6 you're looking at something like the wind supplies in
7 Manitoba, or -- or another alternative where someone's
8 bringing you an option to bring in power to your
9 system that's -- that's non-firm, I know in the wind
10 case, there was some consideration given to the -- the
11 wind's capacity factor that was rejected, and what it
12 would take to -- to firm that into supplies for
13 Manitoba, and that's considered in the price you'd pay
14 for wind.
15 And in that, you're considering the --
16 the load pattern of -- of how well the wind generation
17 might match -- might match your needs during a day,
18 during a week, during a season. Is that fair?
19 MR. DAVID CORMIE: Yes.
20 MR. PATRICK BOWMAN: So even something
21 that has no capacity does have a varying energy value
22 to the system in different hours?
23 MR. DAVID CORMIE: Yes.
24 MR. PATRICK BOWMAN: Okay.
25 MR. DAVID CORMIE: I think if you turn

1 to the -- went to the next slide after this one, Mr.
2 Bowman, you can see that it -- we're -- we're showing
3 about 700 megawatts -- seven (7) to eight (8) or 900
4 megawatts of -- of purchases throughout the peak
5 period. The -- the yellow band at the bottom --
6 MR. PATRICK BOWMAN: The drought,
7 yeah.
8 MR. DAVID CORMIE: -- if -- if for
9 some reason that -- that energy was not available in
10 peak period, we could then pre-schedule it under the
11 diversity contracts to guarantee that we're going to
12 get there. The market doesn't necessarily guarantee
13 that you're going to get supplies.
14 But -- so that yellow band there is
15 probably -- we -- we can -- you know, you can --
16 generally, we expect the MISO market to -- to supply,
17 but if the MISO market doesn't -- isn't capable, we
18 can exercise the capacity call rights that we have.
19 MR. PATRICK BOWMAN: Just checking for
20 other notes in the presentation. Give me a moment.
21
22 (BRIEF PAUSE)
23
24 MR. PATRICK BOWMAN: If we go to slide
25 28 of the presentation? There's -- there's a -- a

1 previous slide that I'll just -- I have it on the same
2 page, but it -- it says:
3 "The creation of export class is a
4 convention that recognizes the use
5 of capability temporarily surplus
6 the Manitoba need."
7 So if I -- if we go to slide 28, which
8 is the picture, when you're talking about temporarily
9 surplus the Manitoba need, you're really talking about
10 what I'll call the orange section of that slide.
11 Those are the temporary components to surplus
12 Manitoba's need?
13 MR. DAVID CORMIE: Yes. And -- yeah,
14 the --the firm surplus is temporary.
15 MR. PATRICK BOWMAN: Assuming you
16 don't advance the next plant, and sort of perpetually
17 have some degree of orange in this graph?
18 MR. DAVID CORMIE: Right. This chart
19 assumes that you build new plant just in time to serve
20 Manitoba load. If you advance plant out a year or two
21 (2) years, you're -- you're going to have some
22 additional surplus available.
23 MR. PATRICK BOWMAN: But the yellow
24 part is not temporary. It may be non-firm. It may
25 not exist year to year. But overall long term,

there's -- there's -- you're -- you're going to have yellow. It's just which year it shows up in.

MR. DAVID CORMIE: Yeah, so the -- the initial amount is -- is temp -- it -- it declines gradually over time because of Manitoba load growth. For example, if you go back to 2005, we had about 6 terawatt hours of dependable energy sales. Right now we have three (3).

MR. PATRICK BOWMAN: Yeah.

MR. DAVID CORMIE: Why? Because Manitoba load has grown by -- you know, by 3 terawatt hours in the -- in the meantime, and it's eaten into that -- into that surplus. And -- and by the time we would get to the in-service date of the next plant, that -- that 3 terawatt hours would -- would essentially go to zero, unless we did something in order to create some more dependable energy.

And -- and this is where the hybrid sales come in. You can create dependable energy if the customer that you're selling the power to as a dependable sale is willing to backstop it in a drought. And -- and so we would have never entered into those hybrid sales because we would have run out of that surplus had not the customer said, Hey, we'll have -- we'll supp -- we'll backstop the sales from --

1 from our surplus energy supplies. And so that -- you
2 know, this is -- this is a very simplified
3 illustration. The complexities of -- of imports and
4 exports allow us to do some more things that -- that
5 this chart doesn't show.
6 MR. PATRICK BOWMAN: Okay. But moving
7 on to that yellow component up above, that's not the
8 component that's temporary. You're -- you're never
9 going to have that based -- needed to supply
10 Manitoba's firm loads. That -- that's always going to
11 be there, and that's part of the reason you've made
12 the case for additional export transmission.
13 MR. DAVID CORMIE: Yes, the -- the
14 light yellow represents an unknown amount. It will
15 range between, you know, zero and -- and, you know, it
16 could be 12 terawatt hours right now. We call that
17 sur -- spot market sales, or -- or spotted power rate.
18 If you want spotted power, you're going to get it
19 sometime, but you won't get it all the time.
20 MR. PATRICK BOWMAN: But it's not --
21 it's not temporary. It may be transient, show up some
22 years or other, but your system's always going to have
23 it.
24 MR. DAVID CORMIE: Right. And -- and
25 we'll always have it and as we build more hydro, we'll

1 have more of that on average. But we can't guarantee
2 it at any time.
3 THE FACILITATOR: Patrick, five (5)
4 minutes, and would you move the microphone a little
5 bit over, so that when you're speaking, it ends up
6 spea -- you're speaking into it?
7 MR. PATRICK BOWMAN: Sorry. Actually,
8 I can just turn it a bit more, maybe. The -- this may
9 be a quick one. When we were going through the IRs,
10 this is in reference to Coalition 85-F. We don't have
11 to go there, but it -- but it is a -- a -- well, maybe
12 it would help to go there.
13 Well, if we go to the question itself,
14 actually, just to confirm. I understand this question
15 to be asking for an adjustment to what was a MIPUG
16 minimum filing requirement. I just want to ensure
17 that we're -- I know what -- what we have.
18 And what -- what the Coalition does in
19 parts A through E is they go through aspects of the
20 Board orders in the past that had directed certain
21 treatments, and then -- and confirmed that MIPUG MFR-4
22 did not actually include all of those treatments that
23 were previously ordered by the Board. And I -- I
24 under -- what I would understand 'F' to be asking for,
25 and I just want to confirm it, is a -- the -- a best

1 efforts to replicate all of the methods that had last
2 been approved by the PUB from various orders.
3 Is that -- is that fair? Is that what
4 85-F is trying to do?
5 MS. KELLY DERKSEN: The materials that
6 we provided in the Minimum Filing Requirement that
7 depict PCOSS14, assuming one sixteen o eight (11,608),
8 took the perspective that it -- those issues that were
9 being challenged by the Corporation and the effects to
10 PCOSS14 of having incorporated them. Any other issues
11 that have materialized or methodology changes that
12 materialized since the issuance of one sixteen o eight
13 (11,608) in 2008 and largely -- and due to the work
14 undertaken by Christensen, that was not included in
15 the minimum filing requirement that is in reference
16 here.
17 So, for example, Christensen advised,
18 based on their advice, that we should reconsider how
19 we treat Dorsey. And that was work that was done in
20 approximately 2011. And upon conclusion of that
21 advice, we did some of our own analysis and concluded
22 that, yes, we support that change and we will make
23 that change, but that wasn't represented. That wasn't
24 an issue of contention in 116/08. It was not
25 reflected in that analysis.

1 MR. PATRICK BOWMAN: So someone took a
2 perspective that said Hydro brought a cost-of-service
3 study in, had two (2) reviews, one (1) in 2006, one
4 (1) that led to the 2008 Order. That's the last Order
5 that substantially dealt with cost-of-service
6 questions. And out of that Order the Board directed
7 some changes.
8 Hydro's best efforts at producing a
9 cost-of-study that kept everything the same, except
10 for those items the Board changed, so this would sort
11 of be the snapshot of the last methods addressed by
12 the Board or understood by the Board. Thi -- this is
13 the re -- the response that does it.
14 Is -- is that fair?
15 MS. KELLY DERKSEN: I would say that
16 there were other issues identified by the regulator in
17 Orders prior, even to 117/06. So how far back do you
18 go?
19 MR. PATRICK BOWMAN: I'm not trying to
20 go back. I'm just trying to say that the last time
21 the Board substantively dealt with cost-of-service
22 would have been in the Order in 2008?
23 MS. KELLY DERKSEN: In 2008? That
24 would be from an Order perspective, yes.
25 MR. PATRICK BOWMAN: Right. And so

1 they would have received PCOSS08. They would have
2 reviewed PCOSS -- I think -- I'm -- I'm almost
3 positive it was 08. They would have ordered some
4 changes. And -- and if someone was tracking the
5 methods, there would be the PCOSS08 methods. Then
6 there would be those items the Board specifically
7 changed and that would lead to a set of methods which
8 have been applied in Coalition 85.
9 Is -- is that fair?
10 MS. KELLY DERKSEN: Yes.
11 THE FACILITATOR: Patrick --
12 MR. PATRICK BOWMAN: Can you follow
13 from that? I might just give Bill a chance.
14
15 (BRIEF PAUSE)
16
17 QUESTIONS BY CONSUMER COALITION:
18 MR. BILL HARPER: Oh, sorry. Maybe
19 just -- and I'm sorry, just quickly so that, you know,
20 in response to the '08 decision, you -- you revised --
21 you provided the revised PCOSS08 that sort of is now
22 what -- what the Board had told you is what they
23 intended.
24 And I guess my understanding, maybe
25 just to confirm what Patrick said, was that your

1 response to 'F' here is basically taking that PCOSS08
2 and updating it using PCOSS14. And you're using IFF-
3 12, '13, '14 values but using exactly the same
4 methodology as what you had -- as -- as how you had
5 por -- portrayed what would be the impacts using
6 PCOSS08 of implementing all -- all of the directions
7 that the Board gave you through those two (2) -- two
8 (2) decisions, 106 and 108?
9 MS. KELLY DERKSEN: Those directives
10 explicitly identified in 116/'08 have been reflected
11 in PCOSS14 as 116/'08. Any changes in methodology
12 that occurred subsequent to the issuance of that Order
13 were not reflected in that version of PCOSS14.
14 MR. BILL HARPER: And that's what
15 we're asking for. So in response to part F here,
16 that's -- that's what the understanding was. The
17 response to part F was going back and reflecting all
18 those decisions as had been -- as had been made by the
19 Board, you know, to -- to your best efforts of
20 understanding what those decisions were?
21 MS. KELLY DERKSEN: I'm -- I'm not
22 sure if -- if I'm misunderstanding something. But to
23 the extent that there were methodology changes that
24 flowed out of the review that we undertook, which was
25 in conjunction with discussions of -- with the

1 regulator subsequent to the issuance of 116/08 to the
2 extent that there were methodologies not explicitly
3 identified in 116/08 that were implemented after the
4 issuance of that Order, those were not viewed to be
5 direction explicit in 116/08.
6 There were a list of, let's say, 'A' to
7 'H' things, include a more current actual export
8 review, we included that, include one (1) export class
9 without distinction between dependable and
10 opportunity. Yes, that was included. The direct
11 assignment of DSM cost against the export class, that
12 was included. Assign 50 percent of your fixed thermal
13 costs and a hundred percent of your variable thermal
14 costs, that was included.
15 So it was those specific issues and
16 methodologies that were incorporated into PCOSS14 that
17 we now call PCOSS14 version 116/08. So to the extent
18 that new methodologies surfaced after the issuance of
19 that Board Order that were not specifically addressed
20 like Dorsey, that was not reflected in the initial
21 MFR.
22 MR. BILL HARPER: No, but they were
23 reflected in the response to Part F. I think that's
24 all we're trying to understand.
25 THE FACILITATOR: Can -- can Kelly --

1 can Kelly look into that while we take a break? And
2 at the -- as we come back from the break, hopefully --
3 oh, yeah. Turn the microphone on.
4 MR. PATRICK BOWMAN: Other than this,
5 there's only one very minor item that I'll review over
6 the break and we might not even need. I think it's
7 one (1) question for an undertaking. Otherwise, we're
8 -- we're -- we'll -- we'll be done.
9 THE FACILITATOR: Kelly, we're leaving
10 it so that you can sort this out over the break and --
11 MS. KELLY DERKSEN: I don't -- I think
12 -- to clarify, I think I can bring closure to this
13 issue very quickly. The MFR was -- as I described,
14 the response to eighty-five (85) Part F is all of the
15 methodology that underpinned PCOSS08 with direction
16 flowing out of 116/08.
17 The only difference is the underlying
18 revenue requirement difference because we had a new
19 IFF by that point in -- in 2012.
20 MR. PATRICK BOWMAN: So it's an
21 underlying revenue requirement. Does that also mean
22 things like your twelve (12) period weightings were
23 updated to the 2014 modern version?
24 MS. KELLY DERKSEN: Yes.
25 MR. PATRICK BOWMAN: I see nods from

1 the back row.

2 MS. KELLY DERKSEN: Yes.

3 MR. PATRICK BOWMAN: So the input data

4 was -- was PCOSS14. Methods were PCOSS08 as otherwise

5 changed -- directed by the Board differently. And I

6 see nods from the back row, so I'm assuming that's --

7 MS. KELLY DERKSEN: Yes.

8 MR. PATRICK BOWMAN: Okay.

9 MS. KELLY DERKSEN: In this IR, but

10 keep in mind that the one in the MFR number 9 --

11 MR. PATRICK BOWMAN: Is different.

12 MS. KELLY DERKSEN: -- is different.

13 MR. PATRICK BOWMAN: Fair enough.

14 THE FACILITATOR: All right. Let's

15 take a break until 11:15. Thank you.

16

17 --- Upon recessing at 11:01 a.m.

18 --- Upon resuming at 11:16 a.m.

19

20 THE FACILITATOR: All right. There

21 are a couple of things that have been brought up. One

22 is to ask the speakers to speak directly into the

23 microphones. The second is when you're not using your

24 microphone, would you turn it off. Also have the

25 understanding that the Coalition has -- has a side

1 agreement with MKO that we'll allot some more time to
2 the Coalition Group because MKO will divert their
3 time.
4 I'm wondering for Byron and Bill
5 whether our most sensible thing then wouldn't be to
6 think of the forty-five (45) minutes till noon hour,
7 then we break for noon hour, and we continue for up to
8 forty-five (45) minutes for the Coalition Group.
9 I also understand that the General
10 Service Group and the City are trying to coordinate
11 their questions together and would likely take less
12 than a total amount of one (1) hours time, so that
13 we'll take into account as well. And lastly would be
14 the one that if we are able to finish by five o'clock,
15 then we could cycle back if people had a few more
16 questions to ask at that point in time.
17 But with all of that, unless there are
18 any questions on that, why don't we get going with the
19 -- the questions from the Coalition until noon, and
20 then we'll break for an hour and then we'll carry on
21 some more.
22 MR. ALEX NISBET: Thank you, Mr.
23 Grant. To my right we have Bill Harper from
24 Econalysis. He filed some questions on May 9th. We
25 may not be going exactly in numerical order and there

1 also might be some issues that fall on generation and
2 transmission, so at a later date he may bounce back to
3 some of those questions.
4 And as he's already warmed up his vocal
5 cords a little bit on 85(f) from the Coalition, that's
6 probably where he's going to lead off. And so with
7 that, Mr. Harper...?
8 MR. BILL HARPER: Thank you. And,
9 Bill, if you wouldn't mind I might go to noon and
10 maybe -- maybe jump in again when MKO's turn comes up
11 in case -- in case they identify something that they
12 want to talk about. In the meantime, I wouldn't want
13 to take all their time and then find that they want to
14 talk about something. But -- but we'll leave that and
15 see how it works, if that's okay.
16 Actually what I wanted to do first as -
17 - as we've indicated I -- I did file the questions on
18 the topics on the areas that I was going -- going to
19 be asking about. We provided that last week, and I
20 don't propose to go through the same order. I'd like
21 to cycle back because some of the topics have been
22 discussed a bit already, and I'd like to follow up on
23 those first.
24 So the first thing I'd like to cycle
25 back on is the discussion that I guess was being --

1 being had primarily with Mr. Bowman about the
2 inclusion of the capacity adder in the SEP prices for
3 purposes of developing the weighting. And I guess I
4 just want to confirm my understanding before we get
5 into the discussion.
6 And the first thing would be is my
7 understanding is the -- the weighting you use are
8 based on SCC -- excuse me, SEP prices for the period
9 2005 to -- to 2012, if I'm not mistaken?
10 MS. KELLY DERKSEN: The energy prices,
11 yes.
12 MR. BILL HARPER: The energy prices.
13 The weighting on the energy prices, that's right. And
14 basically you've included a capacity adder in the SEP
15 prices for each and every one (1) of those eight (8)
16 years.
17 MS. KELLY DERKSEN: For the on-peak
18 periods --
19 MR. BILL HARPER: Right.
20 MS. KELLY DERKSEN: -- yes.
21 MR. BILL HARPER: Right. And I guess
22 we noted in the materials, both in the materials out
23 of the Application and the -- and in the IR responses
24 that the change that took place in the SEP prices in
25 terms of the view being they were no longer fully

1 reflective of the say peak/off peak differential,
2 occurred about 2009 when the capacity market opened in
3 -- in MISO in that it was really after that point in
4 time that the view was that the SEP prices really
5 weren't totally reflective of what you might expect
6 would be a appropriate differential between peak and
7 off peak?
8 MS. KELLY DERKSEN: Based on the
9 advice from our consultant that that was --
10 MR. BILL HARPER: Well, I guess --
11 based on that, I just like your -- you, in terms of
12 why it would be appropriate to include the capacity
13 adder in the SEP prices that are used to calculate the
14 weighting for the years previous to 2009 as opposed to
15 just the years post-2009, or whether as an alternative
16 a better approach wouldn't have been to maybe just use
17 the SEP price as history for the period post-2009 and
18 include a capacity adder in every single year.
19 I'd just -- just like if you -- to --
20 to get your thoughts as to whether the way you've done
21 it perhaps doesn't result in some double counting for
22 the period between 2005 and 2009?
23 MR. DAVID CORMIE: Mr. Harper, there's
24 always been a short-term capacity market. What
25 happened in 2009 is that MISO set up their voluntary

1 capacity option, and in -- in -- and the issue is that
2 -- that, you know, energy prices --
3
4 (BRIEF PAUSE)
5
6 MR. DAVID CORMIE: Yes, I was -- I was
7 just saying that there's always been a short-term
8 capacity market and -- and that we've been
9 participating in that. It's only in 2009 that MISO
10 set up a -- an auction that -- that you can now use
11 the -- you know, the MISO value is the value of -- of
12 short-run capacity.
13 But the energy prices, where there was
14 the SAP price or spot-market prices or whatever price
15 you want to use as -- as -- to determine the value of
16 the energy did reflect that we ran out of capacity at
17 some point because Manitoba load was -- was needing in
18 that.
19 And -- and generally, that was at the
20 end of October when you have -- and -- and so it was
21 October that was always constraining. And so because
22 of that October demand, that limited the amount of
23 capacity that we could take to that -- to that
24 capacity market, whether it's bilateral prior to 2009
25 or post-2009 under the capacity auction.

1 MS. KELLY DERKSEN: I'll just follow
2 on to that. In terms of application, you know, the
3 first decision is -- is: Do you accept the -- the
4 methodology change? And so -- and there is arguably a
5 debate to be had about whether the use of an
6 internally-generated, embedded cost of a peaking plant
7 derated based on our Curtailable Rate Program is
8 compatible with the use of the proxy for short-run --
9 that we use for short-run marginal costs as reflected
10 in -- in the energy market.
11 So, you know, that's a discussion to be
12 had. And I think, longer term -- I think, ideally, if
13 we had a market that was less volatile for capacity
14 from a theoretically per -- a theoretical perspective,
15 it would make more sense to put apples to apples
16 together, if you will, based -- energy prices as -- as
17 based on the -- the external market along with
18 capacity, the value of capacity in that market.
19 We don't have that or we don't think
20 that that is -- that market is robust enough to
21 provide information that is reliable for that. So
22 once you get beyond that, then it becomes a question
23 of: How do you apply it?
24 And what we have done for illustrative
25 purposes only is said, Okay, let's go back to the --

1 the period in time that we're talking about, which is
2 2005, add the capacity adder in each of the peak
3 periods -- so essentially two thousand (2,000) hours a
4 year -- and see what the effect in terms of cost
5 depiction by class is, but that it -- it's
6 illustrative, as we have said in our materials this
7 morning, and that we haven't concluded on how to best
8 implement that capacity adder.
9 MR. BILL HARPER: Just follow up on
10 that, and I know that's the response you gave Mr.
11 Bowman as well, would it be fair to say that one (1)
12 of the questions still pending might be, if we're
13 going to incorporate it, for what years we do
14 incorporate it and what years we don't incor -- we
15 don't incorporate it going forward?
16 MS. KELLY DERKSEN: That's what I was
17 trying to say in a very long-winded way. There's a
18 couple of operational issues, if you will. One is the
19 time frame that you incorporate it. The second is the
20 period within the year that you incorporate it.
21 MR. BILL HARPER: And I guess maybe
22 just building on that last question, I know Mr. Bowman
23 was asking you about seasonal, what seasons you -- you
24 put it in, in spring or fall or maybe even summer.
25 I guess the other question I would ask:

1 Is there still perhaps a debate to be had around how
2 you define the peak period? I mean, you've put in the
3 peak period as defined as for SEP pricing, which is a
4 peak, a shoulder, and a -- an off-peak periods.
5 You know, I -- I know both MISO and
6 your own definition of marginal costs uses a different
7 definition for "peak period" and whether there's
8 perhaps a debate to be had around which -- which
9 definition of peak -- peak period should be had --
10 used, as -- as well as which definition of seasons
11 shou -- should be used and whether -- whether you have
12 -- or whether you have a particular firm view on that
13 at this particular point in time.
14
15 (BRIEF PAUSE)
16
17 MR. MICHAEL O'SHEASY: Mr. Harper,
18 this is Mike O'Sheasy again. And I -- I think the
19 issue of what is the exact time period to which these
20 capacity components, these marginal capacity
21 components for generation, should be imputed for the
22 SEP inclusion for the weighted energy prices, I -- I
23 think that is still an issue of debate or
24 investigation or research.
25 And I'm -- I'm not sure it's

1 appropriate right now to say whether we ought to use
2 the on-peak times for MISO or -- or time-of-use rates.
3 I -- I would just suggest that this is something that
4 should be further discussed. And I was try -- as I
5 was trying to explain to Mr. Bowman, it's not -- to
6 me, it's not necessarily a -- a factor of -- it's got
7 to be an on-peak period with a definition to it.
8 There can't be other real time
9 methodologies for computing a -- an adder such as
10 probability of peak, things like that. So let me just
11 summarize to say that's still a subject of research.
12 MR. BILL HARPER: Okay, fine. I think
13 that's -- that's sort of what -- what I was just try -
14 - trying to get an understanding of, of whether that's
15 the way right now. I guess my -- my last question in
16 this area is a fairly simple one. And that was at
17 Coalition 54(a) we'd requested information on the MISO
18 capacity prices for each year since the market had
19 started.
20 And I guess in the response you gave
21 us, the zone 1, which I think is the zone that
22 Manitoba Hydro participates in, the -- the zone 1
23 capacity prices for basically 2013/'14 up until now.
24 And I guess I was just wondering whether -- were there
25 -- were there earlier prices available, or did the

1 zone 1 market really only start in 2013/'14?
2 I know that's when you started to
3 participate, but whether existed a market before then
4 in zone 1 for which you could provide prices, as we
5 asked for, or the market didn't start in zone 1 until
6 '13/'14?
7
8 (BRIEF PAUSE)
9
10 MR. DAVID CORMIE: Yeah, Mr. Harper,
11 if you look at response 'A', it indicates that we
12 didn't begin participating until the MISO planning
13 resource auction was established in March of 2013 for
14 delivery starting that summer.
15 MR. BILL HARPER: Right. What I was
16 trying to clarify was whether -- I mean, that's year
17 you started participating. Whether -- whether the
18 market existed in years earlier than that and you
19 didn't participate, but there still would have been a
20 price established, or whether that was the fir --
21 like, whether that was the first year the market
22 started up and you were in there for the first year?
23 MR. DAVID CORMIE: I -- I think we
24 were in there for the -- for the first year. I -- but
25 I'll have to check and find out whether there were

1 market prices available prior to that time.
2 MR. BILL HARPER: Okay. If maybe we
3 could just log that as a follow-up, that -- that would
4 be great.
5 Okay, my -- my second area of follow-up
6 to the questions you were -- or discussion you were
7 having with Mr. Bowman had to do with the allocation
8 of the thermal stations.
9 And maybe if we can talk about the coal
10 and gas, and maybe talk about them separately, because
11 I -- I wanted to follow up on the -- some -- on the
12 responses you gave to Mr. Bowman when it came to the
13 coal, because my understanding in reading the
14 application and the IR responses was that, in
15 principle, your view was that coal should be allocated
16 just to domestic, but since there were so few dollars
17 involved, the materiality of it was such that putting
18 it in the pool didn't make a lot of difference in
19 terms of the results. And putting it in the pool made
20 the allocation model a -- a lot simpler. You didn't -
21 - a -- a lot -- a lot simpler to do.
22 And so it's really a matter of
23 simplicity and the fact -- a materiality that led to
24 putting it in the -- putting -- putting coal in -- in
25 the -- in the pool as opposed to treating it

1 separately. And it seemed to me that when the
2 discussion Mr. Bowman and you had some more almost
3 principled reasons. And I don't use that in any
4 negative sense, because I think simplicity is an
5 important principle.
6 But you had some other principled
7 reasons as to why you thought putting coal in the pool
8 was -- was appropriate besides just materiality and
9 making the model sort of sim -- simpler to run. And I
10 just wanted to clarify whe -- whether that was the
11 case, and if perhaps you could maybe just sort of --
12 sort of, in short, form a snapshot what you think
13 those -- that that -- those other principles are, if
14 there are any.
15 MR. DAVID CORMIE: That's right. You
16 know, we were having a very technical discussion of
17 whether they should be in or out. And -- and I'm a
18 firm believer that they should be out. But for --
19 MR. BILL HARPER: Ouf of the...?
20 MR. DAVID CORMIE: Export class.
21 MR. BILL HARPER: Okay.
22 MR. DAVID CORMIE: But from -- from --
23 for the policy reasons of keeping it simple, and not
24 trying to parse every transaction or every resource,
25 we decided that we will -- we will put it in and --

1 and it -- and the dependable class will pick up its
2 fair share of costs. Because for planning reasons,
3 it's there. You know, there's a whole bunch of
4 reasons that you can say it's in. And those would
5 all, you know, be arguments that, 1) I would say that
6 shouldn't be in. Then we'd say, Well, okay, for
7 simplicity reasons, let's just put it in and not argue
8 over -- argue over it.
9 MR. BILL HARPER: And I think in both
10 the presentation that you made and in the discussion
11 you had with Mr. Bowman, you were sort of explaining
12 that really while there's no legislative reason why
13 gas stations couldn't be used for exports, there were
14 both practical reasons from a market and an economic
15 perspective as to why you would never use gas or ther
16 -- thermal stations to -- to support exports.
17 And that if I was to take that argu --
18 if I was to take that on a principle basis, one could
19 -- one could make the argument still that gas
20 stations, which have a lot more costs in the model,
21 should also not be -- should also be not allocated all
22 to exports. But again, perhaps from a simplicity
23 perspective and the fact that the gas stations who did
24 the -- the net book value is just going to be
25 depreciating over time. It -- it makes sense to put

1 them in the pool.

2 Is -- is that a -- is that a fair

3 characterization, or were there some other principle

4 reasons why you thought it was useful to continue to

5 put gas in the pool?

6 MR. DAVID CORMIE: I think they're in

7 the pool because -- for simplicity reasons. But you

8 could imagine -- let's say natural gas was priced at

9 zero, had zero variable costs. Then why wouldn't we

10 run them?

11 MR. BILL HARPER: Right.

12 MR. DAVID CORMIE: And we could be

13 running them for export, right? So it's -- it's kind

14 of, you know, just my view of where the -- where --

15 where energy prices are going. And -- and we always

16 have the disadvantage that our -- that our -- our gas

17 turbines are -- cost twice as much to produce a unit

18 of electricity as a combustion turbine in the market.

19 The heat rate is thirteen (13) to fourteen (14). The

20 market heat rate is around seven (7). So unless the

21 fuel is abs -- it becomes free, it doesn't make sense

22 to run them when I can go to the market and get

23 energy.

24 And, you know, there were years of -- I

25 can't remember, was it just after they came into

1 service, I -- probably around 2001, where market
2 prices were really high. And even though our heat
3 rate was high, it still made economic sense to
4 dispatch them based on economics. I don't see that
5 happening again. And I -- and I -- and I think that
6 was one (1) of the -- ended up being one (1) of the
7 reasons that your -- that, you know, from an
8 environmental perspective now, we wouldn't -- we
9 wouldn't dispatch gas to generate energy when a market
10 can produce it much more efficiency (sic) with less --
11 much less carbon emissions.
12 So I think if we got to that point, we
13 would -- as a Company, we would probably put a carbon
14 adder on there to make sure that they only run when
15 they were necessary, and not to trade around them.
16 MR. BILL HARPER: You mean necessary
17 from a domestic purpose?
18 MR. DAVID CORMIE: That's right.
19 MR. BILL HARPER: And maybe just sort
20 of to wrap this one up, and I noted in -- there was
21 some discussion around sort of justification versus
22 use when you're thinking about, you know, how you're
23 going to treat something. And I wanted to sort of
24 clarify the justification for the gas stations.
25 Because in the IRs that were asked this time, the jus

1 -- as to why they -- why they've been built.
2 The -- the responses were clearly that
3 they had been built for domestic purposes. And
4 actually a similar question was asked about ten (10)
5 years ago in the 2005 review. And the IR response at
6 that point in time that said they were entered into
7 for export pur -- purposes. And I just wanted to sort
8 of -- sort of try and reconcile those two (2)
9 responses.
10 And I guess -- and at the same time,
11 perhaps, offer -- I think Day -- Daymark has a
12 question very similar to this. So if they want to
13 follow-up at this particular point in time with --
14 with any -- any issues around this that they have,
15 that -- that's perfectly fine with -- fine with --
16 with me. But maybe if you'd just reconcile those two
17 (2) response -- responses for me?
18 MR. DAVID CORMIE: The original
19 justification for the combustion turbine is different
20 from what they're used for today. And I -- I accept
21 that, yes.
22 In -- they were put in -- into service
23 at a time where they could firm up hydro sales that we
24 would normally expect to deliver off the hydro system,
25 and provided a backstop. And I think now with the

1 MISO market, that we could do the same firming, just
2 in the market without relying on those.
3 So, you know, I think the -- the role
4 of the stations has changed because of the economics.
5 MR. BILL HARPER: Okay. No, that's
6 fine. That goes to that issue about justification
7 versus role now that I think we -- we talked about
8 during -- during your presentation.
9 MS. KELLY DERKSEN: I think I might
10 want to add something here, please, if you don't mind.
11 You know, we have, subsequent to the stakeholder
12 meetings, undertaken -- in 2014 extensively reviewed
13 cost allocation to the export class, and not just cost
14 allocation to the export class but whether an export
15 class at all was -- continued to be the appropriate
16 approach to go down, and we have debated that issue
17 extensively.
18 And we have landed to a perspective of
19 really, one of a -- a policy perspective. Number 1,
20 we built for -- to serve Manitoba load, and I think a
21 good case could be made that there are no fixed costs
22 or very little fixed costs incurred to -- to undertake
23 exports on that basis.
24 The driver of the cost is to serve
25 Manitoba load. The driver of the cost is domestic

1 customers, and you allocate all of your fixed costs to
2 domestic customers. And so, you know, we really have
3 to either accept that decision, because otherwise,
4 we're going to be debating why every resource was put
5 on our system, whether it continues to appropriately
6 represent today its use versus why it was implemented,
7 and you -- you're down this road.
8 And it's -- like I said before, it's a
9 circle that we'll never get out of. So we've made --
10 we've made that decision. That said, this was -- was
11 the point of all of this actually, sorry, Bill.
12 If there was a cost, I think, that we
13 knew was specifically attributed to exports, we put
14 that infrastructure in place to serve an export sale,
15 I think it would -- it would -- we would be hard
16 pressed to say that we shouldn't assign that cost
17 against the export class, notwithstanding this policy
18 decision that we've made to say, Let's share the cost
19 of the embedded transmission and generation system
20 between dependable and domestic customers.
21 MR. BILL HARPER: I -- I think we may
22 come up with a discussion on an issue like that
23 tomorrow actually, but we'll leave that till -- till
24 tomorrow, so -- till -- till tomorrow to -- to
25 address.

1 I'd like to turn now, and maybe sort of
2 the basis for this -- this is the first question we
3 sent you in writing, if Manitoba Hydro wants to
4 understand where we are, but I'll go -- go through it
5 orally for purposes of the transcript.
6 I'd like to turn now to your response -
7 - the response you gave to PUB-70(a), where basically,
8 you were setting out what were the interest/
9 depreciation/operating costs for a number of specific
10 facilities. You had coal, natural gas, diesel, AC
11 collectors, and you also had, I guess, the facil --
12 facilities you were talking about with Mr. Bowman
13 which was the existing HVDC and Dorsey converter
14 station in terms of what were the specific costs for
15 each of those.
16 And I guess having got those costs
17 there, and I guess in the case of the Dorsey and the
18 HVDC, it was about $137.6 million in total, was -- was
19 identified in the response. I guess putting that
20 aside, we noticed in going through the IR responses,
21 there were a number of costs in the cost allocation
22 that weren't allocated just -- just -- they were
23 allocated to functions, but they weren't allocated to
24 specific facilities as part of your overall cost of
25 service.

1 And actually what the question was just
2 trying to understand, were there any of those costs --
3 to what extent those costs have been allocated to
4 functions but not to specific facilities were actually
5 captured in -- in the cost you -- you had a hearing
6 on.
7 And so the written question we had,
8 we're going through a number of those areas where we
9 understood costs were allocated to functions but not
10 to specific facilities, and saying, Are those costs
11 part of what's in here?
12 And I'm not interested in knowing -- if
13 it is, I don't really want to know what the dollar
14 value is. I just want to know yes or no, is -- is it
15 in or out? so we have an understanding of what these
16 costs that are reported here re -- re -- represent.
17 MS. KELLY DERKSEN: And just a quick
18 question back to you. Are you talking about from a
19 generation and a transmission perspective?
20 MR. BILL HARPER: Yes, yes. So it'd
21 be -- you know, I mean, we -- we've got costs there
22 for coal generation, costs there for natural gas
23 generation. We also have costs there for -- you know,
24 the HVDC facilities in the Dorsey Converter.
25 And I assume if the answer is different

1 for transmission versus generation, maybe you can let
2 me know. But I would assume in many cases the answer
3 would probably be the same in both cases. And so I
4 don't know -- I can run through the series of what we
5 understand are costs that are allocated on general
6 nature to functions. And you can tell me whether or
7 not they're built into these specific costs that you
8 have here. Is that --
9 MS. KELLY DERKSEN: That's fair. I --
10 I have to --
11 MR. BILL HARPER: Sure.
12 MS. KELLY DERKSEN: -- just confirm.
13 With that generally, though, you know, we don't look
14 at facilities in that finite level of detail. For
15 cost allocation purposes, once you pool your costs
16 into a function transmission, you know, we don't often
17 go and start piecing out, you know, this transmission
18 line here and how much indirect costs or overhead
19 costs should be attributed to it, or even, conversely,
20 hy -- hydraulic facilities.
21 You know, we have mitigation costs, for
22 example, that sit in the generation function. What do
23 you do with that? And so -- but your question is:
24 Did you fully load them or didn't you really?
25 MR. BILL HARPER: And I guess the

1 reason it's important -- I think it's important in
2 certain instances because in this case you're talking
3 about moving roughly 100 -- well, I understand about
4 137, $138 million that's associated initially with
5 tran -- labelled initially as transmission in your
6 financial systems, you know, the -- the HBDC, Bipoles,
7 and the converter.
8 And you're talking about moving them
9 into generation, those costs into generation, and
10 treating them as a generation cost, in which case they
11 get classified and allocated on a different basis.
12 And so it was really tho -- really it's -- if they're
13 all in the same function, I don't have a problem.
14 It's when you're moving -- you
15 subsequently then start moving facilities around into
16 a different function, I want to understand what --
17 what costs are going with it, and what costs maybe
18 aren't going with it that maybe in another perspective
19 should have gone with it, if I can put -- if I can put
20 it that way.
21
22 (BRIEF PAUSE)
23
24 MR. BILL HARPER: So I don't know
25 whether you have a blanket answer or whether you want

me to work through the individual items, or whether it's -- I -- I think the blanket answer is no, none of these indirect costs are moved over. But I wanted to get a confirmation for that.

MS. KELLY DERKSEN: It -- the answer is it depends.

MR. BILL HARPER: That's what I was afraid of.

MS. KELLY DERKSEN: And I'll take you as far as I can go, and I might have to get Mike Dust to help us out here. If we're talking about Dorsey, to the extent that there is direct -- direct overhead assigned to Dorsey, labour costs, for example, that would go with Dorsey when you move it from transmission to generation.

To the extent that there is overhead, so common costs of buildings and, you know, communications and other kinds of infrastructure and -- and labour also, to the extent that -- that that asset no longer sits in generation doesn't automatically translate in a one (1) for one (1) assignment of that indirect cost in the generation function.

MR. BILL HARPER: So I think those would apply to such things as, you know, your common -

1 - your common settlement cost centres that you have in
2 generation and transmission. You've got a number of
3 settlement cost centres that are common. That -- that
4 response would apply to those?
5 MS. KELLY DERKSEN: Yes, yeah.
6 MR. BILL HARPER: It would also apply
7 to the operating depreciation costs associated with
8 com -- your communications and any control settlement
9 cost centre. And --
10 MS. KELLY DERKSEN: Right.
11 MR. BILL HARPER: -- and I guess the
12 other thing is -- I guess the other things that sort
13 of are, the thing is is you -- you allocate a share of
14 regulated assets to generation, share-regulated assets
15 to transmission.
16 I assume it would -- that same answer
17 would -- would apply to those, too, if we're --
18 because some of those allocations are based on
19 operating or labour costs. And -- but to the extent
20 you move Dorsey over, you would move over a share of
21 the regulated asset costs as well.
22 MS. KELLY DERKSEN: Right. I mean,
23 there are some dire -- indirect effect of doing that
24 because you're still allocating ultimately even labour
25 costs or other operating expenses largely in

1 conjunction with the investment that you put in place,
2 that -- that role or that labour that those people are
3 serving, so there's some indirect effect of that but
4 not directly.
5 MR. BILL HARPER: Actually, before I
6 leave this, I believe Mr. Bowman actually wanted to
7 follow up on a question on this, on your response to
8 PUB number 70, as well. And since I stole some of his
9 time, I'll give him some of my time to follow up on
10 this question here.
11 MR. PATRICK BOWMAN: Actually, it was
12 an easy question. It's just, in your presentation at
13 slide 20 you have illustrative RCC impacts of Bipole
14 III in service. And I don't know what PCOSS scenario
15 that came out, but I was curious if it was effectively
16 the PUB 70 scenarios for the years where Bipole III
17 shows up or whether it's -- it's something different?
18
19 (BRIEF PAUSE)
20
21 MS. KELLY DERKSEN: Mr. Bowman, the
22 slide is simply taking the -- the net investment of
23 Bipole III and layer it on to PCOSS14 and making some
24 assumptions in terms of having to keep in balance --
25 either net income has to fall because your rates are

1 insufficient to support that level of investment or
2 you have to increase your rates because it all has to
3 balance -- balance out.
4 So it's just taking that investment and
5 adding it to PCOSS14 amended.
6 MR. PATRICK BOWMAN: Just looking at
7 PUB-70 then. There was a page -- page 8 of that has a
8 -- or page -- sorry, pa -- page 6 of 11, I think, has
9 a revenue requirement scenario that's an estimate of
10 2017/'18 which doesn't yet have Bipole III in it. And
11 then you go down to the next page which jumps to
12 2020/'21 which does have Bipole III in it. It's --
13 it's about the middle of that page, but it also has
14 other changes that start to kick in.
15 So all you've done in this -- in this
16 scenario that's in the presentation is take PCOSS14
17 and add in effectively that one (1) row called Bipole
18 III, not all the other changes that go on in -- in the
19 time frame?
20 MS. KELLY DERKSEN: Yes, that's --
21 that's what we have done for the slide, yes.
22 MR. PATRICK BOWMAN: But would you be
23 able to produce the summary tables associated with
24 that slide 20 cost-of-service run, including the unit
25 costing?

1 MS. KELLY DERKSEN: We can make that
2 available.
3 MR. PATRICK BOWMAN: And when I say,
4 "unit cost," I mean be -- not net of --
5 MS. KELLY DERKSEN: RCCs.
6 MR. PATRICK BOWMAN: -- NER -- not net
7 of any NER. Like, the unit costing tables have a
8 habit of taking off the next export review, so they
9 don't actually show costs. So if we can do the unit
10 cost table to not taking the NER?
11 MS. KELLY DERKSEN: I have your point.
12 We'll -- I've got it. I'm -- I'm not sure how easy or
13 not that is, but we'll qualify it appropriately.
14
15 --- UNDERTAKING NO. 2: Manitoba Hydro to provide
16 all PCOSS schedules with
17 the scenario provided on
18 slide 20 of Manitoba
19 Hydro’s COSS workshop
20 presentation from May 11,
21 2016, as well please
22 provide a version of
23 Schedules B2 and B3
24 without deducting the Net
25 Export Revenue (i.e.

1 similar to MIPUG/MH-I-6A)

2

3 THE FACILITATOR: Patrick, over the

4 break maybe you could -- or at the lunch hour maybe

5 you could write out the question for us.

6 MR. PATRICK BOWMAN: No problem.

7 MR. DAVID CORMIE: Mr. Harper, I -- I

8 just want to go back to that question you had on

9 thermal class. We -- we answered PUB-2A and 'B'. I'm

10 not sure if you're familiar with that answer that

11 talks about whether directly assigning thermal plant

12 costs to the expert class and whether there's cost

13 causation reasons for doing that. And -- and that --

14 and then we talk about it from that perspective, but

15 then, from a policy perspective, how we actually have

16 traded.

17 And I think that's an excellent

18 description of where we're at.

19 MR. BILL HARPER: Okay, fine. Okay,

20 thank you very much. I guess, my -- my next question

21 had to do with, I guess, the tra -- trading desk costs

22 that you -- you've identified in for -- for allocation

23 in the cost-of-service study.

24 And I was trying to relate the trading

25 desk costs noted there with the responses to some of

1 the IRs which -- and I noted there there were external
2 marketing settlement cost centre -- centre associated
3 with generation. There was another external marketing
4 settlement cost centre associated with transmission.
5 I noticed that all the trading desk
6 costs all come out of the generation -- costs
7 allocated to -- to generation. And so I was trying to
8 -- maybe if you could just explain for me briefly
9 what's the difference between the external marketing
10 settlement cost centre that's in generation versus
11 transmission, and why the trading desk is only
12 associated with the generation side, but doesn't pick
13 up any of the transmission side.
14
15 (BRIEF PAUSE)
16
17 MS. KELLY DERKSEN: The trading desk
18 area costs that underpin the -- the generation
19 function relate to labour costs associated with Mr.
20 Cormie's area. The costs that sit in transmission are
21 all MISO fees.
22 MR. BILL HARPER: So -- so that --
23 that settlement cost centre is picking up nothing but
24 MISO fees then?
25

1 (BRIEF PAUSE)

2

3 MS. KELLY DERKSEN: That's true, yes.

4 MR. BILL HARPER: Okay. I'll -- I'll

5 have a follow-up on that tomorrow when we come to

6 transmission, but that -- that's -- that's great for

7 now. I wanted to follow-up a little bit on -- on your

8 spider diagram, if -- if I could.

9 And actually it has to do with --

10 because I noticed that in -- in the response you gave

11 to both some of the coalition IRs and one (1) of the

12 GAC IRs there were a number of lines, transmission

13 lines, that were emanating from genera -- they seemed

14 to be -- appear to be emanating from generating

15 stations that you were aser -- actually classifying as

16 transmission. Some you tended to classify as

17 transmission. Some ones emanating from generating

18 stations you seemed to classify as generation.

19 And I was wondering if you could maybe

20 -- maybe confirm the fact that some of those line

21 emanating from generating stations -- I think if you

22 look at GAC number 6, you classify it as transmission,

23 non-tariffable, but they're still transmission -- and

24 how you make that distinction between what's

25 considered, if the line is coming out of a generating

1 station it -- it should be in transmission, or it
2 should be -- rem -- remain in generation, just -- just
3 from a principle perspective.
4 DR. DAVID SWATEK: Okay. Thank you,
5 Mr. Harper. Yeah, just referring back to the spider
6 diagram, I -- I thought this really -- I -- I thought
7 this really summed things up well. The -- the
8 transmission lines, or the transmission grid, it's --
9 it's not just a matter of -- of having transmission
10 lines. They have to -- to -- they have to -- they
11 have to work as a grid to serve all transmission
12 customers simultaneously. The term that's used in the
13 industry is the -- that they must be simultaneously
14 used and useful to all transmission customers. Those
15 -- those are the generators that hook up to the grid
16 and the load.
17 So the transmission grid allows any
18 particular load that hangs off of it to be served by
19 all of the generation. A change in any of those loads
20 simultaneously changes the flows on all lines. So
21 those -- those lines that are simultaneously used and
22 used by all transmission customers, we -- we
23 functionalize those as transmission. Now, there --
24 there will be a category of lines that we call
25 'generation outlet' that serve one (1) purpose, and

one (1) -- and one (1) purpose only, and that is to take the power, the -- the megawatts, the energy from a particular generator and to -- and to inject that -- that power into the grid.

Those -- those transmission lines, those generation outlet lines, serve no other -- serve no other purpose other than to move the power from the generator to the grid. Now, over time as -- as new loads pop up you have to find some place to hook up that -- that new load, and you -- there -- there might be a long trans -- transmission line that -- that takes a remote generator to -- to the grid. There's a new cottage load that pops up. You tap that transmission line, and you are now serving load off of that -- that line.

Now, if -- if you were able to continue to serve that load without that initial generator, that is if you could serve that load from the grid then -- then that chunk of -- of line between the new load and the grid becomes transmission, and the piece of line between the new load and the generator is still generation outlet.

MR. BILL HARPER: You know, that's pretty helpful because if I -- if I think of it then as if -- if the load is only flowing one way and if

1 the load -- and if the load on the line is only
2 dependent on the output of the -- of the output of the
3 generator, then its generation outlet which to some
4 extent if we go to the conversations you were having
5 earlier on you can almost -- you can apply that
6 analogy to the Bipole -- Bipole lines.
7 They're nothing to do with load. It's
8 all got to do with how much is coming out of the
9 generation in the north, and that defines for you
10 precisely what the use of those lines is. And so
11 that's sort of -- seems to be a common principle I can
12 then look at when I'm looking at all these lines.
13 Would that be fair?
14 DR. DAVID SWATEK: Yes, I believe
15 you're interpreting the concept of used and useful.
16 MR. BILL HARPER: Okay. Okay, fine.
17 No, thank -- thank you. That's -- that's been very
18 useful. The...
19
20 (BRIEF PAUSE)
21
22 MR. BILL HARPER: Sorry, I'm just
23 trying -- okay. I wanted to go to the net -- net
24 revenue allocation, and maybe this is -- just before
25 lunch is a good way to try and put this up, and sort

1 of the treatment of diesel adjustments in IFF.12.

2 And my understanding is, in looking at

3 the -- I was looking at the MMF, minimum fire

4 requirement number 2 from MIPUG, that you adjusted the

5 -- you increased the -- the depreciation for diesel

6 for roughly $1 million, and you increased the asset

7 value for diesel on average by about $12 ½ million to

8 account for the -- for the impact of customer

9 contributions, and sort of -- to sort of roll that out

10 of the -- that impact out -- out of the revenue

11 requirement?

12 MS. KELLY DERKSEN: Yes, if I can just

13 sort of talk at a high level what we're attempting to

14 do here. Based on the tentative diesel settlement

15 agreement, we have agreed to allocate some or -- some

16 of the net export revenue to that group of customers

17 to that class.

18 So -- but one of the challenges is

19 there is a fair amount of funding of the investment in

20 diesel that is made by other parties, and doesn't ever

21 get reflected in our cost of service study. So based

22 on the terms of that tentative settlement agreement

23 we've said, Okay, we're going to notionally up tick

24 that investment.

25 So if it was sitting on our books at

1 ten dollars ($10) we're going to represent it as
2 twenty (20) because that represents the -- the actual
3 investment made by both Manitoba Hydro and other
4 parties in order to decide, or in order to determine
5 their allocated portion of the net export revenue.
6 MR. BILL HARPER: No. And I
7 understand, you know, the purpose of the diesel
8 funding was -- I -- my -- the more simple thing was to
9 give the diesel -- the diesel class a share of the net
10 export revenues based -- without the -- the share of
11 the revenues that sort of -- not export revenues but
12 to sort of make this adjustment for capital
13 contributions.
14 What I was struggling with is the fact
15 that by making these adjustments, if -- if I'm
16 correct, to depreciation net book value you have
17 basically increased the depreciation costs that are
18 allocated to diesel by about a million dollars by --
19 by removing -- by sort of doing this adjustment for --
20 for depreciation?
21 MS. KELLY DERKSEN: Yeah, that would
22 be the -- the outcome of increasing notionally the
23 investment.
24 MR. BILL HARPER: And similarly by
25 increasing the -- the -- sort of the value of the

1 assets to diesel by about $12 1/2 million, you
2 increased the amount of interest costs that are
3 allocated to the diesel community through the allo --
4 through -- through your cost allocation model.
5 MS. KELLY DERKSEN: Yeah. Similarly,
6 yes.
7 MR. BILL HARPER: All right. And so I
8 guess I was trying to -- and I can't wrap my mind
9 around this, and I was hoping maybe you could either
10 off the top of your head, or if not, maybe do a back-
11 of-the-envelope calculation and tell me: Are -- is
12 the diesel class better or worse off by the fact now
13 we've increased the depreciation costs, we've
14 increased the interest costs, but we've also --
15 through the allocation of net export revenues, we've
16 increased the -- we've -- we've given them a bigger
17 share of net export revenue.
18 When I take -- when I take all that and
19 add it out, does the diesel class have more costs
20 attracted to it or less costs attracted to it in total
21 than -- than it would have if we hadn't made any of
22 these adjustments which -- which are, you know, linked
23 to the Diesel Funding Agreement, which was supposed to
24 be of benefit to the diesel class, if I can put it
25 that way?

1 (BRIEF PAUSE)

2

3 MS. KELLY DERKSEN: It's a bit

4 convoluted, Mr. Harper.

5 MR. BILL HARPER: My question was

6 probably a bit convoluted, too, so I apologize.

7 MS. KELLY DERKSEN: There is a net

8 benefit to be had for the diesel customers on account

9 of assigning some level of the net export revenue to

10 their class.

11 MR. BILL HARPER: Even after you

12 account for these increases?

13 MS. KELLY DERKSEN: Even after.

14 MR. BILL HARPER: Oh, okay.

15 MS. KELLY DERKSEN: It might be a

16 little bit lesser than it would have otherwise been in

17 the absence of, let's say, depreciation costs flowing

18 to that customer group or interest.

19 But there is a net benefit to them now

20 because of the terms of the tenta -- tentative settle

21 agreement and the fact that, subsequent to the

22 drafting of that agreement, there was direction from

23 this regulator in -- in about 2010 that said, You

24 shall apply grid rates that are applicable to the rest

25 of the system for residential customers to that class.

1 Things become very elusive in terms of
2 what that all means. And, you know, we can't go much
3 farther than that.
4 MR. BILL HARPER: No, I appreciate it.
5 I was just trying to understand whether, at the end of
6 the day, the result was coming out the way people
7 thought it was going to come out going in, and I think
8 you've confirmed that, maybe to a lesser extent, but
9 it still is.
10 Bill, I was going to suggest it looks
11 like about -- this is probably a good time for me if
12 people wanted to take your break now.
13 THE FACILITATOR: That sounds great.
14 Why don't we break till one o'clock. And -- and in
15 that time, do check with MKO whether they need to get
16 -- have some of their time back or not.
17 MR. BILL HARPER: Okay.
18 THE FACILITATOR: Thank you. Thanks,
19 everyone.
20
21 --- Upon recessing at 12:04 p.m.
22 --- Upon resuming at 1:01 p.m.
23
24 THE FACILITATOR: Good afternoon,
25 everyone. Hopefully everybody's refreshed for the

1 afternoon. And my understanding is that, Bill, it's
2 back to you. And between you and MKO, there's until
3 quarter to 2:00.
4 MR. BILL HARPER: Sounds good. Did
5 you have something you wanted to...
6 MR. DAVID CORMIE: Yes, Mr. Harper. I
7 -- I looked into the MISO voluntary capacity auction
8 that was established in April of 2009. You had to be
9 -- your generation and load had to be in the market
10 for -- in order to participate in that auction.
11 Manitoba Hydro was -- wasn't --
12 external participants like Manitoba Hydro weren't
13 allowed in until 2013. That's why we -- we didn't
14 participate. But that was a monthly auction, and in
15 most months, the capacity cleared at zero, except for
16 the peak month in which MISO was going to peak.
17 So we have available those monthly
18 prices, which would be different than the annual
19 prices are available. And if you're still interested,
20 we can assemble those monthly prices.
21 MR. BILL HARPER: That would -- that
22 would -- those would be for the years prior to
23 '13/'14?
24 MR. DAVID CORMIE: From 2009 to 2013,
25 when the planning auction began.

1 MR. BILL HARPER: I -- I think, if
2 it's rel -- if it's easy -- if it's easy to get, I
3 think -- I think that would be useful. It would go to
4 the point I think Kelly had been making about sort of
5 -- about some sort of volatility, uncertainty about
6 the prices. I think -- I think that would help.
7 MR. DAVID CORMIE: Yeah. So we'll --
8 we'll try and assemble those.
9 THE FACILITATOR: So, Bill, I take it
10 that takes away the undertaking that you had, although
11 there's this information that will be sent in to you--
12 MR. BILL HARPER: Yeah.
13 THE FACILITATOR: -- and to everyone
14 else?
15 MR. BILL HARPER: Well, I think -- I
16 think there's still an undertaking. What we've done
17 is we've clarified exactly what's going to be
18 provided.
19 THE FACILITATOR: I guess that's true,
20 yes. Thanks.
21
22 (BRIEF PAUSE)
23
24 MR. DAVID CORMIE: Yes. Manitoba
25 Hydro will provide the monthly clearing prices for the

1 MISO voluntary capa -- capacity auction between April
2 2009 and June of 2013.
3 MR. BILL HARPER: Okay. Thank you.
4 Okay. I -- I think -- I'd like to turn now to -- and
5 it's a bit of a bridge between transmission and
6 generation, but I'd like to turn now and talk briefly
7 about the transmission service and it's -- and that --
8 that you contract for when you're making purchases or
9 making exports, and how the costs and revenues
10 associated with that transmission service are treated
11 in the -- in the cost-of-service study.
12 And the IR where we asked questions on
13 this was Coalition number 91.
14
15 (BRIEF PAUSE)
16
17 MR. BILL HARPER: And here we were --
18 we're trying to ask in terms of how the -- and my
19 understanding, maybe just as a bit of an introduction,
20 when it comes to do doing exports, effectively, you
21 contract with yourself under the -- to transport the
22 exports to the US bor -- border, if I'm not mistaken.
23 And so, basically, there would be --
24 you're basically paying yourself for -- for the export
25 service that gets the export -- transmission service

1 that gets the exports to -- to -- from, you know,
2 where -- wherever they're coming and, I guess, common
3 bus bar, wherever, to the US border.
4 MR. DAVID CORMIE: Yes, for -- for the
5 long-term sales, transmission service needs to be
6 provided from Dorsey to the border, and then from the
7 border to the customer's load. So that would be
8 transmission service under Manitoba Hydro's tariff and
9 transmission service under the MISO tariff.
10 If this is a net -- if -- if this sale
11 is going to be used to serve network load in MISO,
12 there's no charge for the customer to take that
13 service. He's eligible for that service, and so he
14 gets it for free. Manitoba Hydro is responsible for
15 reserving firm transmission between Dorsey and the
16 border to get that power. And we would take service
17 under the Manitoba Hydro tariff, and -- and
18 notionally, we pay our transmission service, but it
19 would be, you know, one (1) division of Manitoba Hydro
20 paying another division, so there's no cash action
21 transfer.
22 MR. BILL HARPER: So those -- those
23 cost and remedies, they don't show up in IFF-12 at
24 all, or they're netted out, or do they show up -- do
25 the revenues show up one (1) place in IFF-12 and the

1 costs show up someplace else in IFF-12?
2 And I'm going to ask another question
3 about the cost of service later on, but I'm trying to
4 understand because it is predicated in IFF-12 and the
5 '13 and '14 cost forecast in that.
6 MS. KELLY DERKSEN: For cost of
7 service purposes, it would be the net amount that we
8 would deal with that would be in the revenue
9 requirement because, as Mr. Cormie explained, if it's
10 simply division to division, there's not -- it -- it's
11 -- costs less from a IFF per -- perspective. But to
12 the extent that there are transmission costs incurred
13 separate and distinct from that, that would be
14 incorporated in the revenue requirement and in cost of
15 service.
16 MR. BILL HARPER: I was going to get
17 to that second piece later on. I was dealing just now
18 with what you pay yourself. And so, effectively, in
19 neither the revenue requirement nor the cost of
20 service, if are -- look, do those costs of revenue
21 show anywhere, if I'm -- if I could understand what
22 you're saying correctly?
23 MR. DAVID CORMIE: The -- the revenues
24 or cost did show up in the IFF, but, in effect, no
25 cash was moved. I understand now in the new -- in the

1 new IFF, we are not putting the revenues and the costs
2 in, because it just -- it -- it -- there is no real --
3 MR. BILL HARPER: No, I was just
4 wondering.
5 MR. DAVID CORMIE: -- costs.
6 MR. BILL HARPER: Because from a cost-
7 of-service perspective, conceptually, you could think
8 of the revenues you pay yourself as going and offset -
9 - as going offset for the cost of transmission and the
10 transmission function, but the -- you know, but the
11 costs are part of the cost of exports, which is
12 treated differently in the cost of service study.
13 And so you could think that, while from
14 a financial perspective, it nets out to zero, from a
15 cost-of-service perspective, if you were to track the
16 costs, you know, to -- and attribute them to exports,
17 and track the revenues and attribute them to
18 transmission, you would end up with a different
19 result, even though the net at the end of the day is
20 sort of a net -- net to -- to Manitoba Hydro, and I
21 was just trying to understand.
22 It sounds like you didn't do any of
23 that in -- in the cost-of-service study, if I'm not
24 mistaken?
25 MR. DAVID CORMIE: There could be an

1 effect if the allocations were different, right?
2 MR. BILL HARPER: Right, okay.
3 MR. DAVID CORMIE: If they were
4 allocated exactly the same, it would be a wash.
5 MS. KELLY DERKSEN: Right. And -- and
6 I got your point, that if -- for -- if, for example,
7 there was an internal transaction that occurred, that
8 rate would be charged, let's say, to Mr. Cormie's area
9 and on account, let's say, on an export sale that
10 might be treated in cost of service on the basis of
11 generation or transmission and versus the folks where
12 that rate originated, whi -- which would be the
13 transmission folks, and that would be allocated --
14 that revenue could be allocated on a 2CP basis
15 different.
16 MR. BILL HARPER: Yeah.
17 MS. KELLY DERKSEN: But I -- I can't
18 ima -- even if that were the case, we're not talking a
19 lot of dollars, here.
20 MR. BILL HARPER: Okay, no. And
21 that's what I was just interested -- I was -- I like
22 to talk about things in principle and I like to talk
23 about things from a materiality perspective, and I was
24 interested, do you have any sense say for '13/'14 what
25 was the notional level of transfer -- notional level

1 of dollars involved in this?

2 And if you -- and I -- I -- you know,

3 if that's something that's fairly easy that's fine, if

4 it's -- if it's a lot of digging I -- I can -- I can

5 pass on the question.

6 MR. BYRON WILLIAMS: Mr. -- Mr. Grant,

7 it's Byron Williams in the back. We're following the

8 discussion with interest but there's a bit of a fan

9 here, so if we could ask the -- the Hydro panellist

10 just to raise their voices, politely, that would be --

11 that would be appreciated.

12 MS. KELLY DERKSEN: If it's critical,

13 we can find it. It will take some digging for us to

14 get it.

15

16 --- UNDERTAKING NO. 3: Manitoba Hydro to provide

17 MISO capacity market

18 prices for period 2009

19 through 2013

20

21 MR. BILL HARPER: No, then I -- I

22 wouldn't bother. Thank -- thank you very much. I

23 guess the other thing was, and you -- you alluded to

24 it, Kelly, was the fact -- and I think it's also in

25 the -- Part -- Part C of the IR response here, is that

1 there are third-party revenues that you get from --
2 yeah, there are third-party costs and, you know,
3 third-party revenues you get related to exports.
4 And if you get -- is revenue back to
5 Manitoba Hydro, and are those -- those revenue --
6 those net revenues, they -- they would be treated as
7 an export -- as export revenues? Is that how -- is
8 that how they're treated in the cost of service study?
9 MS. KELLY DERKSEN: I believe -- it
10 takes a little bit of digging, like I said, to get
11 this information. But both the cost and net costs
12 with respect to transmission service, as well as any
13 revenues on a net basis would both flow into -- into
14 the export class.
15 MR. BILL HARPER: So -- so they both -
16 - yeah, they'd -- they be under your treatment of --
17 they'd be netted out and show up under export revenues
18 is basically what would happen then?
19 MS. KELLY DERKSEN: That's right, yes.
20 That's what I was trying to say, I'm sorry.
21 MR. BILL HARPER: Okay. No, that's --
22 that's fine. Now, we switch to the purchase side of -
23 - of the equation in terms of, you know, when you make
24 purchases and the purchases show up. I seen you've
25 got a -- you're -- you're having to pay -- pay for the

1 cost -- pay for transmission to -- as part -- part of
2 the cost of all those purchases.
3 I assume the cost of that transmission
4 service would show up as part of the cost of purchases
5 in -- in your cost of service study?
6 MR. DAVID CORMIE: While Kelly is
7 checking that, at a high level we don't have to pay
8 for transition service when we're purchasing because
9 we're serving our network load with that. And we have
10 a coordination agreement with MISO so that MISO waives
11 the transmission service charges in the US because
12 we're purchasing to serve our load.
13 MR. BILL HARPER: Okay.
14 MR. DAVID CORMIE: And in Manitoba our
15 -- our firm load is already taking -- network service
16 is already paying for it so to charge them it would --
17 it would be charging twice. So there's -- there may
18 be a small MISO scheduling fee associated with the
19 energy but it's a -- it's a very small portion of the
20 -- of -- if -- as if you were -- compared to if you
21 were wheeling power from MISO through Manitoba to get
22 to Saskatchewan, where they would have to pay the --
23 the full tariff because they don't have that
24 arrangement with MISO that we have.
25 MR. BILL HARPER: Okay. Is there

1 something you wanted to add, Kelly?

2 MS. KELLY DERKSEN: Just that it would

3 show up -- that cost would show up in -- as -- in

4 purchase power.

5 MR. BILL HARPER: Okay, fine. Okay,

6 thank -- thanks. If we could may -- maybe -- okay,

7 I'm finished with that one. I just want to get my

8 next one here.

9 If we could turn -- turn to the

10 response you gave to Coalition-22G, and this is

11 dealing with the -- I guess the curtailment priority

12 stack for different types of exports, and domestic

13 load.

14 MR. DAVID CORMIE: Yes.

15 MR. BILL HARPER: And I guess I -- I

16 was just curious, there were a couple of -- I was

17 looking at -- if we look at the priority -- wait --

18 wait until they scroll down there a bit further, I

19 think. It's always on the last page. Right. I was

20 curious.

21 When you got number four (4) there

22 "energy only surplus" that -- I assume that's surplus

23 export sales is what you're talking at -- under

24 priority rating number four (4) there under energy

25 only?

1 MR. DAVID CORMIE: Yes.
2 MR. BILL HARPER: So actually if you
3 were to think of where would say -- where would the
4 SEP load that -- that you serve fit in that stack or -
5 - or order, just out of curiosity? I was just trying
6 to get -- to get the relativities of it.
7 MR. DAVID CORMIE: The SEP load is --
8 is not included in this table because SEP is
9 considered to be firm load unless we curtail with
10 notice. So -- so in an emergency, the -- I think the
11 SEP notice period is forty-eight (48) hours, or -- you
12 know what, it -- it's more relative to these types of
13 emergencies. So we would have to know about the
14 emergency well in advance before we -- we would be
15 curtailing SEP load.
16 MR. BILL HARPER: So it -- it would
17 fall on the list somewhere below the Manitoba
18 Curtailable Rate Program, then, I assume, is -- is
19 what you're saying?
20 MR. DAVID CORMIE: Okay. Now, it --
21 it -- we've only ever curtailed the SPE (sic) load
22 once, and that was in the winter of 2003/'04. And we
23 curtail -- we -- we curtailed it in November for the
24 winter season because there could be a situation where
25 we were energy short. And so we curtailed it for the

1 season, but we did it with a very long notice.
2 It's not -- it's -- it's not an energy
3 product that is, like, an interruptible export
4 product. We -- we serve it and -- and if it -- and --
5 and if we feel that there's a risk to Manitoba load,
6 we give the customer notice, so that he can get onto
7 his alternative fuel. And he needs notice in order to
8 -- to make that transition, say from propane -- off --
9 off electricity onto propane. And so it's -- it's a
10 long lead time curtailment. Whereas, these are --
11 these curtailments deal with -- with short-term
12 emergencies.
13 MR. BILL HARPER: Okay. And -- and
14 the other issue was, there was, you know, in the sort
15 of -- the second report from Christensen, in the
16 responses, there was a lot of discussion about the hyb
17 -- hybrid power sales in terms of how they should be -
18 - whether they should be opportunity or whether they
19 should be dependable and how they should be treated.
20 And I was just curious, how -- how they would fit
21 within this curtailable pri -- priority stack, if you
22 -- if there -- if -- and if you were trying to fit
23 hybrid power sales in the stack.
24 MR. DAVID CORMIE: Well, the hybrid
25 sale is not defined from the customer's perspective.

1 It's something that Manitoba Hydro has named it. So,
2 you know, it's -- it ends up being a -- a credited
3 capacity in dependable energy. And so if -- hybrid
4 sales are no different than a normal system power
5 sale.
6 MR. BILL HARPER: Oh, okay, fine. So
7 they would fit under --
8 MR. DAVID CORMIE: It would --
9 MR. BILL HARPER: -- category number 8
10 then, there?
11 MR. DAVID CORMIE: Yeah, it would just
12 fall into the traditional thing. It's just that the
13 question, you know, about hybrid sales is: Who is
14 supplying the capacity and who is supplying the
15 energy? And it's -- they're supplied by the purchaser
16 to Manitoba Hydro, so that we can make the sale back
17 to them.
18 MR. BILL HARPER: Okay. No, I
19 understand. I just thought it might be useful, had --
20 to have that perspective as well in terms of under --
21 sort of looking at this debate about -- about --
22 MR. DAVID CORMIE: Yeah, so it -- it
23 falls under capacity and energy number -- number 8.
24 MR. BILL HARPER: Okay. I had a
25 couple of fairly short questions, I think. The first

1 one (1) has to do with if -- if you -- if you maybe
2 turn to Coalition 61A.
3
4 (BRIEF PAUSE)
5
6 MR. BILL HARPER: And -- and here --
7 here we were talking about -- and I -- I just want to
8 clarify the answer, because I -- and I think --
9 because I think may -- maybe the answer wasn't quite
10 correct, in the sense that we were talking about the
11 treatment of purchased power costs. And in the
12 evidence, you made response to it was allocated on a
13 proportional basis. And the IR was really asking,
14 What do you mean by 'proportional'? And the response
15 was it was based -- proportional based on their total
16 -- tot -- total energy.
17 I assume what you may -- and if it's in
18 the pool, it's based on its total weighted energy, as
19 opposed to just total energy? I just want to make --
20 make sure I'm clea -- clear on that.
21
22 (BRIEF PAUSE)
23
24 MS. KELLY DERKSEN: Mr. Harper, it is
25 -- 'proportional' means, in this context, where we

have defined dependable sales, to be anything -- to be energy available above that needed to serve Manitoba load. Anything above dependable energy is assumed to be opportun -- made opportunity sales, energy. That equates to approximately a 50/50 split. Within that, then, it's assigned on a variable basis.

MR. BILL HARPER: So -- so one (1) of these purchased power costs are then prorated between domestic, dependable, and opportunity sales based on the relative kilowatt hours associated with each of those three (3) groups?

(BRIEF PAUSE)

MS. KELLY DERKSEN: I have to clarify that. I was -- I was just wrong. It is just based on a weighted energy allocator.

MR. BILL HARPER: You know, that -- that's what I thought. I -- I thought the answer wasn't quite right, and I just wanted to make sure that I -- I wasn't misreading it. So it is a weighted energy allocator. Okay, fine. Thank you very much.

The...

(BRIEF PAUSE)

1 MR. BILL HARPER: Okay. The -- the
2 next clarification I had was -- and actually it refers
3 to two (2) different IR responses in which I seem to
4 be getting two (2) different answers to the -- answers
5 to -- to the question. And I guess if I look at
6 Coalition 65A, it states that MISO fees are included
7 in transmission?
8
9 (BRIEF PAUSE)
10
11 MS. KELLY DERKSEN: Okay so far.
12 MR. BILL HARPER: That -- that's how I
13 was interpreting that was that MISO fees were included
14 in -- in transmission, where if I looked at -- maybe
15 if I looked at PUB-14, it seems to -- it says they're
16 allocated as part of the generation.
17 I was just wanting a clarification as
18 to precisely which of the two (2), you know -- which
19 of the two (2) functions the MISO fees were included
20 in.
21 MS. KELLY DERKSEN: Could you give me
22 the other reference again, please?
23 MR. BILL HARPER: It was PUB-14.
24
25 (BRIEF PAUSE)

1 MS. KELLY DERKSEN: MISO fees, Mr.
2 Harper, are in transmission.
3 MR. BILL HARPER: Are -- are in -- are
4 in transmission. And in that case, they would be
5 allocated to domestic and dependable exports based on
6 that 2 -- 2CP all -- allocator.
7 MS. KELLY DERKSEN: And opportunity as
8 well.
9 MR. BILL HARPER: And there's
10 opportunity as well.
11 MS. KELLY DERKSEN: Yes.
12 MR. BILL HARPER: Okay. Fine. No,
13 thank you very much. Actually, I think, Bill, that's
14 all I have for this. There's some grey areas between
15 generation and transmission, but I think -- I think if
16 -- if you say it's an opportunity, then we may cycle
17 back but -- but for now, I -- I think I'm done, and we
18 can move on to the next Intervenor.
19 THE FACILITATOR: Very good. Thanks,
20 Bill.
21 So we're now onto Green Action Centre,
22 I think. Yes, if you could introduce yourselves and -
23 - and then carry on. Thank you.
24
25 QUESTIONS BY GREEN ACTION CENTRE:

1 MR. BILL GANGE: Apparently, I thought
2 that Mr. Chernick needed no introduction to this gang,
3 but Mr. Chernick has been the expert witness for the
4 Green Action Centre for the -- the last four (4) or
5 five (5) interventions that we've had in front of the
6 PUB. And so I'll turn it over to him and I'll keep
7 quiet.
8 MR. BILL HARPER: Right. Good luck,
9 Paul.
10 MR. PAUL CHERNICK: Thank you. How's
11 -- how's that work for everybody, the position of the
12 mic? Okay.
13
14 (BRIEF PAUSE)
15
16 MR. PAUL CHERNICK: I -- I had a
17 couple of -- well, maybe it's only one (1) sort of
18 general question before we get started and that is:
19 How -- how far does Hydro take the -- the concept of
20 postage-stamp rates? Is that just within a class the
21 rates should be uniform across the Province? Or is it
22 also that for a certain kind of service, whether that
23 be say primary service? Whether it's overhead or
24 underground? Whether it's new or old? Whether it's
25 more rural or more urban?

1 That postage stamp means that that
2 service is -- or that cost item should be evenly
3 spread out for all customers without chopping it into
4 pieces based on things like vintage and -- and the --
5 the technology involved? Is it -- is that a
6 comprehensible question? We're talking philosophy
7 here.
8 MS. KELLY DERKSEN: Philo -- a
9 difficult one. I think generally speaking, postage-
10 stamp rate-making is the overarching framework that we
11 apply. Within that framework, there are tools
12 available to us to look at options to ensure that not
13 undue cross-subsidies occur on account of extending
14 service, for example, to a particular customer who
15 might be an outlier.
16 And that at least conceptually would be
17 known as -- as a feasibility test, which would produce
18 a contribution. And that contribution notionally is
19 there to say it cost -- it incrementally costs more to
20 serve -- provide that service to that customer than
21 the incremental revenues generated out of -- out of
22 that particular service.
23 And a contribution then, I guess by
24 definition, means that it makes that particular
25 service or expansion feasible.

1 MR. PAUL CHERNICK: Right. Yes, and -
2 - and I understood that -- that for individual
3 customers within a class you may say, well, you -- you
4 sort of fall outside of the normal distribution of
5 this class and you require, in the case of a
6 transmission customer, you require a transmission line
7 to be built where we wouldn't have one otherwise. Or
8 for a residential customer we have to -- to add a
9 kilometre of -- of lines and poles to get to you, and
10 you're going to have to pay for some of that.
11 That -- that really wasn't my question.
12 My question was: So if you -- and if -- just take one
13 (1) simple example, for underground versus overhead
14 distribution service. If you knew that one class was
15 served primarily with underground and that that was
16 more expensive pre mile than -- than overhead would
17 your perspective be, well, that class should be
18 allocated higher cost all else equal more per
19 kilowatt, for example, than a class that's served
20 primarily with overhead?
21 Or is your sense, look, wherever you
22 want to be in the Province if you're taking -- using
23 this kind of equipment, this kind of equipment, this
24 kind of service, unless you're one of those outliers
25 that we have to build a special line for, your class

1 is going to get allocated a share of everything.
2 Overhead, underground, single phase,
3 three (3) phase, urban, rural. We're going to put it
4 all in one (1) big pot and stir it up, and that's
5 fair. That's consistent with the postage-stamp rate,
6 not just between customers within class but between
7 classes.
8 Or is your thought, gee, you know, if
9 we knew that one of the -- you know, the GS small was
10 mostly a little off, this is in -- in downtown which
11 we're expensive to serve, we would want to charge you
12 more per kilowatt for distribution than medium GS
13 which are served mostly overhead out in the suburbs or
14 something. I'm just trying to figure out where your
15 philosophy lands so I know basically where -- where
16 we're agreeing on things, where we're disagreeing,
17 what -- what your intention is.
18 And maybe some of this you haven't
19 really confronted.
20 MS. KELLY DERKSEN: It's -- it's a
21 very conceptual question. It's a -- it's a
22 challenging one. Mr. Barnlund may, Mr. Rainkie may
23 want to weigh in here. This is -- I'll -- I'll come
24 at from -- come at it from this perspective and see
25 where we go.

1 I view po -- I view postage stamp rate
2 making, as I said, as the overarching rate design
3 principle applied to both -- both of our utilities but
4 within that context cost causation is a primary
5 driver. So to the extent practical and reasonable we
6 try to identify specific costs belonging to specific
7 customers or groups of customers.
8 So if there is a circumstance where a
9 customer class has certain facil -- dedicated type of
10 facilities, we attempt to directly assign tho -- the
11 cost of those facilities directly to the class.
12 I -- I can't think of a specific
13 circumstance off the top of my head where it's that
14 clean. And even, you know, we've talked a little bit
15 in our submission about radio feeds. And our
16 consultant has identified specific radio -- radios spe
17 -- specific to a customer and whether that we should
18 be directly assigning the cost of those radios to that
19 customer.
20 The challenge is we don't have a cust -
21 - one (1) customer in a class, so either assign all of
22 the cost to the class and just that class bears
23 responsibility for that or you start segmenting your
24 system and creating specific rate treatment for -- for
25 individual circumstance, so there's a bit of a

1 balance.

2 And it's not easy answer. And it, at

3 times, can depend on -- on materiality. It, at times,

4 can depend on how identifiable are those costs, can

5 someone else -- like Dr. Swatek talked about this

6 morning, it might be in -- put in place for one (1)

7 function or one (1) customer, but other customers can

8 eventually attach to it.

9 So, you know, those are considerations

10 that also need to be assessed.

11 MR. PAUL CHERNICK: Okay. Thank you.

12 I wanted to just ask one (1) question about your

13 presentation which was on page 30 where you're showing

14 the -- the exports and the loads. And you talked

15 about maintenance of the hydro in the summer resulting

16 in your having lower exports in the summer than you --

17 you do in the -- the winter.

18 So if the -- I'm trying to figure out

19 just how to phrase this. But, basically, does the --

20 the maintenance in the summer basically bring the

21 system to a point where your summer ability to -- or

22 your -- your summer reliability and reserves are

23 comparable to the winter and if you had much higher

24 loads in the summer you'd have difficulty doing all of

25 your maintenance or is that a very small part of the

1 difference between your summer and winter loads?

2

3 (BRIEF PAUSE)

4

5 MR. PAUL CHERNICK: Did the question

6 make sense?

7 MR. BILL HARPER: I -- I think so.

8 MR. DAVID CORMIE: Let me -- let me

9 explain what's going on. And then we can talk about

10 the question again. We try not to take maintenance

11 outages in the winter right now because -- and it's

12 mostly driven by reliability. And it's DC

13 reliability. We barely have enough DC capability to

14 handle the generation that's available in the winter.

15 And so if we're going to take DC

16 outages, we will want to take them in the summertime,

17 and when the Manitoba load is lower. And that means

18 that when you're taking out a valve group for 250

19 megawatts or a 500 megawatt valve group or a -- you

20 know, a large -- you want to tuck into that outage --

21 the generation outage at the same time. So you -- so

22 that you -- you schedule the big ones on the DC and

23 then you do the generation underneath of it.

24 If you did the -- if you took a DC

25 outage in the winter now you would be taking away from

1 the load-serving capability of the system to serve
2 Manitoba load. So until we get Bipole III we're going
3 to probably continue to avoid winter maintenance
4 because of reliability issues. The DC puts
5 constraints on reliability. Once you have Bipole III,
6 we're going to have a lot more freedom to schedule
7 generation outages any time of the year because Bipole
8 III will have spare capacity that when you take that
9 capacity out of services there's still room to get all
10 the generation out. So that's generally why we have
11 more hydro available in the wintertime than we have in
12 the summertime.
13 And I think on average we take out
14 about -- there's 300 megawatts on average is about the
15 number. And there's about a hundred that goes out in
16 the winter and, say, four hundred (400) in the summer.
17 And so that's the three hundred (300) difference
18 that's probably showing up in this chart. There will
19 be room after we get Bipole III to do more uniform
20 maintenance scheduling because reliability won't be an
21 issue. Not only because of Bipole III, but the new
22 interconnection will give us 700 megawatts more of in
23 -- in -- import capability. So you can maintain the
24 same reliability year round because of the additional
25 resources that are available.

1 MR. PAUL CHERNICK: Okay. Thank you.
2 Well --
3 MR. DAVID CORMIE: The other thing is
4 that most of the surplus energy that this power system
5 produces, it produces in the summertime. Because you
6 -- we have high water flows, and high water flows
7 result in lower heads. And lower heads means that the
8 -- the power system produces less -- has less capacity
9 in -- in high water years than it does in -- in -- or
10 in high water seasons in the water.
11 So it's -- what you're seeing is there
12 is that in -- and because we've had lots of high water
13 years, this is -- there's a little bit of a de-rate
14 there because of the -- of the high flows. And that
15 tends to penalize summer generation, where in the
16 wintertime we're not spilling and so you don't have
17 those head losses. So there's -- there's kind of
18 those two (2) factors that are -- are showing up in
19 this chart.
20 MR. PAUL CHERNICK: Okay. I -- I
21 guess my -- my limited experience with hydraulic
22 generation is -- is -- caused me just to get confused
23 by that last part. But you're saying that in the
24 summer you're generating more from the plants so that
25 --

1 MR. DAVID CORMIE: There's -- there's
2 spillage going on in the summer --
3 MR. PAUL CHERNICK: Yeah.
4 MR. DAVID CORMIE: -- of 2014. So the
5 tail water is higher, so that means --
6 MR. PAUL CHERNICK: Oh, the tail water
7 is higher. Okay.
8 MR. DAVID CORMIE: Yeah, the tail
9 water is higher, the head is lower, the hydro stations
10 produce less power under high water flows than in the
11 wintertime, when river flows are now back into the
12 normal range. And that -- so the hydro stations have
13 a de-rate in the summer.
14 MR. PAUL CHERNICK: And -- and are
15 those flows being driven by environmental...?
16 MR. DAVID CORMIE: Yeah, that's --
17 we're in a wet cycle and -- and, you know, there's
18 probably -- you know, in the summer of 2014 there was
19 a flood going on, and so there's a lot of spillage
20 occurring on the system which de-rates the hydro
21 system.
22 MR. PAUL CHERNICK: Okay. I -- I
23 think I've got that now. I was having a little
24 difficulty with the idea when -- when there's more
25 water we get less generation, but --

1 MR. DAVID CORMIE: We don't like to
2 say this, but there are times when we have too much
3 water.
4 MR. PAUL CHERNICK: Yeah. Oh, yeah, I
5 -- I -- I'm aware of that. Okay. And -- okay, my
6 next question has to do with the way that -- that
7 exports are -- not how they're allocated, but just how
8 -- how they're modelled in PCOSS14. And I got the
9 impression from Coalition 21 that the total exports
10 are taken from the 2013/'14 actual export levels. But
11 the split between dependable and opportunity for
12 allocation purposes is taken from a -- a projection
13 for 2014 through '20.
14 And have -- have I got that right?
15 MS. KELLY DERKSEN: I just want to
16 qualify that our treatment in PCOSS14 versus PCOSS14
17 amended is different.
18 MR. PAUL CHERNICK: Oh, that may be one
19 (1) reason I'm confused.
20 MS. KELLY DERKSEN: So on the basis of
21 PCOSS14 amended, we are -- at least the intention is
22 to look at a five (5) year average of dependable and
23 opportunity sales based on those years 3 to 8 of the
24 IFF. And -- but for PCOSS14 amended -- just give me a
25 moment, please.

(BRIEF PAUSE)

MS. KELLY DERKSEN: The -- the qualifier that I wanted to add is that in PCOSS14 amended as well as PCOSS14, we only used one (1) year of data from the '13/'14 fiscal year. But the intention is to move -- in the future is to move to a five (5) year average based on years 3 to 8 of the IFF.

MR. PAUL CHERNICK: Okay. So right now, as I pose the -- in the question, that's the way it works. There's sort of a -- a mismatch between the total amount of -- of exports that's coming from the -- from the actuals for '13/'14. The split between dependable and opportunity is from the five (5) year forecast.

You're planning to go to a five (5) year forecast for everything?

MS. KELLY DERKSEN: Yes.

MR. PAUL CHERNICK: Okay. All right. In response to the -- the Centre's Request 8, you gave us the times of -- of the top load, fifty (50) peak hours summer and winter.

And my first question was: Are those times the hour ending for the -- the one (1) hour

1 ending at that time or the hour that begins at that
2 time? And since these peaks are all in the middle of
3 the day, so I can't tell how you're treating the first
4 or last hour.
5 MS. KELLY DERKSEN: You know, Mr.
6 Chernick, I wouldn't know. You'd have to --
7 MR. PAUL CHERNICK: Okay. Good. That
8 -- that's fine.
9 MR. DAVID CORMIE: Mr. Chernick, those
10 are hour ending. So the hour ending 1400 would be
11 between one o'clock and two o'clock.
12 MR. PAUL CHERNICK: Okay. So it's
13 hour -- hour ending. That's -- that's very helpful.
14 And would that be consistent in the way you've
15 reported load data throughout the -- the responses,
16 that your convention is you always use hour ending
17 when you're reporting things?
18 Or would we sort of have to go through
19 each response? Because there was also one where we
20 asked about the time of -- of peaks on substations,
21 and we got some times. And -- and if the answer is
22 that we have to ask about each one, then -- then
23 that's okay, but -- or we can make that an
24 undertaking. This is just to get things clarified so
25 we can see how time periods match up for pricing and

1 other purposes.

2 MR. DAVID CORMIE: Mr. Chernick, I

3 think we need to look at this because, you know, if

4 you look at the char -- top of the chart there, it

5 says, Six o'clock to 22:00. And peak is from our

6 ending 7:00, which would be from six o'clock to 7:00.

7 We would -- in this part of operation,

8 we'd label that as hour ending 7:00. But -- but if

9 you're trying to catch the peak, that would be

10 inconsistent with what this table -- so we'll just

11 check on that.

12 MR. PAUL CHERNICK: Okay. I'm not

13 sure I understood what -- what you were saying. You -

14 - you were saying that --

15 MR. DAVID CORMIE: Oh, I'm saying if I

16 -- if I read the table, it says Jan -- December,

17 January, and February, six o'clock to 22:00.

18 MR. PAUL CHERNICK: Right.

19 MR. DAVID CORMIE: But I just said to

20 you that would mean that would be hour ending 6:00.

21 Well, hour ending 6:00 is not an on-peak hour. That's

22 an off-peak hour.

23 MR. PAUL CHERNICK: Oh, okay, okay.

24 So in that case, for this particular response, the --

25 the heading seems to be hour beginning.

1 MR. DAVID CORMIE: That's right, and
2 so I think we -- we would need to confirm that with
3 you.
4 MR. PAUL CHERNICK: Or it's actually
5 the time. It's not hours at all.
6 MR. DAVID CORMIE: That's right.
7 MR. PAUL CHERNICK: It's the -- from
8 six o'clock to 10:00 p.m. And in the table, it's
9 probably hour ending, but you need -- I understand
10 that you would need to confirm.
11 MS. KELLY DERKSEN: We -- we can
12 confirm that, Mr. Chernick. Yeah, we have.
13 MR. PAUL CHERNICK: So could we just
14 make that a -- an undertaking that you'll -- you'll
15 check whether the times provided in the --
16 MS. KELLY DERKSEN: I'm sorry, I
17 should clarify that. We have confirmed with our load
18 research --
19 MR. PAUL CHERNICK: Oh.
20 MS. KELLY DERKSEN: -- folks, and they
21 have confirmed that it's hour ending.
22 MR. PAUL CHERNICK: Is it? Okay.
23 These are hour ending.
24 MS. KELLY DERKSEN: Hour ending.
25 MR. PAUL CHERNICK: Okay. And do you

1 believe that that's consistent through your --
2 throughout your responses, or could we ask you to take
3 a sweep through to see where -- where you've given us
4 times, whether they're all hour ending?
5 MS. KELLY DERKSEN: We would have to
6 follow -- follow up with our load research folks.
7 MR. PAUL CHERNICK: So could we make
8 that an undertaking? So just confirm whether all the
9 times that were -- we were given in the discovery
10 responses are for hour ending.
11
12 --- UNDERTAKING NO. 4: Manitoba Hydro to confirm
13 whether all the times that
14 were given in the
15 discovery responses are
16 for hour ending
17
18 MR. PAUL CHERNICK: Okay. Now, the
19 other thing about this -- this response is that you
20 identify the top fifty (50) hours --
21 MS. ODETTE FERNANDES: Sorry, Mr.
22 Chernick, if I can just clarify that?
23 MR. PAUL CHERNICK: Sure.
24 MS. ODETTE FERNANDES: Are you looking
25 for the hour ending for the responses dealing with the

load research results, or...

MR. PAUL CHERNICK: Well, actually we might have that -- that kind of question about -- I -- I believe we also got hours in the answers about the -- the timing of -- of peaks on -- I think the only place we got answers were on -- on substations.

And I -- I haven't gone through to see whether other places where you gave us times that -- that would be -- that would be ambiguous.

MS. ODETTE FERNANDES: Okay. I -- not that I'm providing evidence, but I've been advised that for load research they're all hour endings. If there's any other inquiries regarding other responses, if you can just let us know and then we'll do our best to look at those.

MR. PAUL CHERNICK: Okay. Maybe we'll --we'll just deal with some of those tomorrow, or Friday. Okay. Going back to the table, you identify the top fifty (50) hours based on generation peaks. And I wonder, is there a reason for using the generation peak rather than the common bus peak since it's the common bus that we're allocating costs for, for the most part?

MS. KELLY DERKSEN: Except that we are also having to allocate costs to the export class, and

1 that's why we have taken it back to generation.
2 MR. PAUL CHERNICK: Okay. And the --
3 but for the -- the export class, you're allocating the
4 -- using this peak -- the fifty (50) peak hours only
5 for the -- for fixed costs, which are going to the
6 firm sales not to opportunity, and so firm sales are
7 half of the total sales and maybe more than half in
8 their highest load hours, I don't know.
9 Would -- I mean, this seems to me that
10 -- that you might want to calculate the -- the fifty
11 (50) hours based on the -- or select the fifty (50)
12 hours based -- based on the -- the loads that are
13 paying for the things that are being allocated with
14 the fifty (50) hours peak. Is that -- am I missing
15 something there?
16 MS. KELLY DERKSEN: You're not missing
17 anything there. The -- the reality was that we -- or
18 the reality is we have metres at various points in our
19 system to -- to measure energy, and we can't
20 differentiate between what is dependable and what is -
21 - is opportunity. And so we made the assumption that
22 the load for opportunity is going to look the same in
23 -- in terms of shape as -- as dependable, and -- and
24 applied that.
25 I suppose you could get to a greater

level of -- of refinement to say, well, you know, they may peak at -- at different periods. They're different types of services. And so it -- the trouble is we don't have metre data to do that, and we'd have to come up with some other kind of allocation, or determination of loads specific to dependable sales.

MR. PAUL CHERNICK: So -- so you have a choice of either all exports are in or all exports are out, and -- and you chose to use the one that had all exports in the -- the measure.

MS. KELLY DERKSEN: I think there's -- I think the -- the answer is, yes. Mayb -- this has evolved over time, as you can appreciate. That initially, in 2003 or 2004, we had just the one (1) export class. There wasn't any rationale to differ -- different -- or the direction was that there was no differentiation between dependable and opportunity, and so it's evolved over -- over that point, but, yes, you're -- you're right.

MR. PAUL CHERNICK: Okay. Could you provide a table like this just sorted for the -- the top fifty (50) peaks at the common bus? I'm looking around the pillar at load research expert.

(BRIEF PAUSE)

1 MS. KELLY DERKSEN: I'm told we have
2 some data. I -- I don't know how you define what --
3 are you just looking to exclude exports? Is -- is
4 that what it is that you're looking for?
5 MR. PAUL CHERNICK: Well, what I was
6 looking to do is -- yes. If -- if you sorted the
7 hours, I'm -- the -- the generation number is -- is
8 fine to have in there, it might actually be useful for
9 some things. But if you just sorted it on the common
10 bus rather than on the -- the generation, you'd wind
11 up with a different set of hours.
12 And I'm just curious about, do you wind
13 up with mostly the same hours just sorted in different
14 order, or do a whole bunch of new hours come in and
15 some of the hours you got here go out, because they're
16 hours when you have a lot of exports but not a lot of
17 common bus load.
18 And I'm just trying to figure out at
19 this point whether this is even really -- whether it
20 matters at all for allocation purposes or whether it's
21 the top fifty (50) hours no matter how you look at it,
22 or, you know, plus or minus a couple hours.
23 So, basically, I assume this just comes
24 from a spreadsheet that has maybe eighty-seven sixty
25 (8,760) hours or at least a lot of high load hours,

1 and that it could be sorted on the common bus column
2 rather than the generation column. And if you could
3 give us that -- that sorting and give us the top fifty
4 (50) hours, that would be helpful.
5 MS. KELLY DERKSEN: We'll -- we'll see
6 what we have and -- and what complexities there are in
7 doing that from the conceptual level. Bring it back
8 to -- to this idea that if we're allocating fixed
9 embedded tran -- transmission cost to dependable
10 exports, it makes sense to include them.
11 MR. PAUL CHERNICK: Right.
12 MS. KELLY DERKSEN: The -- the
13 question is: Is it -- because the -- the data
14 availability in terms of what we meet are -- if -- if
15 that needs to be refined, but conceptually, it makes
16 sense to include exports.
17 MR. PAUL CHERNICK: Okay. And also, I
18 -- I assume that you -- you must have the -- the class
19 loads or your estimates to the class loads for these
20 fifty (50) hours -- or a hundred hours, fifty (50) in
21 the summer, fifty (50) in the winter.
22 MS. KELLY DERKSEN: At -- at common
23 bus are you -- are you talking about? Or what are you
24 --
25 MR. PAUL CHERNICK: Well -- well, the

classes are all the common bus. I mean, but in this -- first -- just for the hours that are listed in GAC-8 and without worrying about the -- sort of the first part of my request, do you have the individual hours -- for each -- each individual hour, do you have a -- a breakdown between the various class loads?

Somehow you averaged those out to get a -- a class 50CP allocator, so I'm assuming that you -- you have estimates hour by hour?

MS. KELLY DERKSEN: We use load factor, so we don't have necessarily energy by class for every hour. And so that's why -- that we haven't provided that information to you. We have that historically based. And we apply that, then, to the full -- an average of the load factor by class. And we apply that to the forecast.

MR. PAUL CHERNICK: Well, okay, maybe I'm getting confused about how you're using these numbers. I thought that whenever you talked about...

(BRIEF PAUSE)

MR. PAUL CHERNICK: We have a consultation going on.

1 (BRIEF PAUSE)

2

3 MS. KELLY DERKSEN: I'm advised that
4 we have some of that data, at least, available --
5 provided already in response to PUB-53.
6 MR. PAUL CHERNICK: Okay. I'll --
7 I'll take a look at that. Let me just clarify what
8 you just said about load factor. I was under the
9 impression that whenever you talked about two (2) CP
10 or allocating on -- on coincident peak, that you meant
11 you were allocating on the class contribution to the
12 average of the top fifty (50) hours. Or the average
13 class contribution during the top fifty (50) hours,
14 summer and winter. So it's the -- the hundred hours
15 all together.
16 Is -- did I misunderstand that? Is --
17 are you really just using a load factor based on a
18 single peak hour or a single peak in the summer and a
19 single peak in the winter?
20 MS. KELLY DERKSEN: No, it's -- it's
21 top fifty (50) hours --
22 MR. PAUL CHERNICK: Okay.
23 MS. KELLY DERKSEN: -- averaged over
24 the course of eight (8) years by class.
25 MR. PAUL CHERNICK: Okay. So --

1 THE FACILITATOR: Paul, I'm -- I'm
2 having a little bit of trouble following. And, first
3 off, could you explain why the common bus might be
4 more preferable to use and how you might use it to
5 alter the -- the allocations for that, so that we can
6 sort of understand the conception of where it is?
7 MR. PAUL CHERNICK: Well, yes, there -
8 - there are some costs, like the non-tariff
9 transmission, which is allocated just to domestic
10 load. And that's the common bus load. And that's
11 being allocated based on the top loads in fifty (50)
12 hours -- fifty (50) hours of -- of peak generation,
13 which is being driven by exports. And then for the --
14 even for things which are also being allocated to
15 exports, the export portion of the generation load is
16 -- is exaggerated here because it includes
17 opportunity.
18 So you could have an hour in which you
19 have relatively low loads for both dependable exports,
20 and for -- for your domestic load. And, therefore,
21 all of the costs that -- the fixed costs are being
22 allocated on the coincident peak and are being driven
23 by that consideration are -- the -- the hours and,
24 hence, the mix of class loads is being determined in
25 large part by the opportunity sales.

1 Now, we don't know how large that is.
2 But I was thinking, Gee, if we had the top fifty (50)
3 hours at the common bus, and the top fifty (50) hours
4 at the -- of generation load, and it turned out that
5 forty-five (45) of the hours were the same in each
6 season, then maybe that it's not -- it indicates that
7 it's not really probably a -- a significant issue.
8 If, on the other hand, thirty (30) of
9 them are different, that would be an indication that
10 there might be -- it might be important.
11 And, similarly, if it turns out that
12 the mix within the fifty (50) hours of the class
13 responsibilities doesn't vary substantially, that,
14 say, in the wintertime, the residential is, you know,
15 within a few percentage points of the same value in
16 all fifty (50) hours -- and it's not that we have some
17 off-peak hour where we're sending lots of power down
18 to -- to Minnesota that -- or there's lots of
19 industrial load off-peak. You know, it -- a very
20 different kind of load shape that -- that's skewing
21 the results.
22 So I -- I assume that they -- that the
23 Company had fifty (50) -- you know, for each class,
24 the -- their estimate of the load, the -- the fifty
25 (50) hours, and was able to -- would be able to give

1 us a value so that we could match them up.
2 And it sounds like maybe they -- they
3 don't really, that they can give us these fifty (50)
4 hours, but those aren't the fifty (50) hours that they
5 used. They don't really have load estimates for those
6 fifty (50) hours, which -- I'm -- I'm a little
7 confused at this point, but I'd like to -- to
8 understand what they're doing and -- and be able to
9 understand whether common bus versus generation really
10 makes any difference.
11 And then even if some -- we can't do
12 anything about it right now, there might be a
13 recommendation to the Board to have Hydro work on a --
14 a methodology that doesn't have this problem, assuming
15 there is one (1). And it might even argue for a
16 different treatment of -- of the export class.
17 MS. KELLY DERKSEN: If -- if I can
18 just dummy this down, because --
19 THE FACILITATOR: Thank you.
20 MS. KELLY DERKSEN: -- that's the only
21 way I can operate, I think that the issue is is that
22 we've made an assumption for cost allocation purposes
23 in order to allocate transmission costs to exports
24 that both dependable and opportunity sales have the
25 same load characteristics, because we have a meter

1 that can't differentiate -- a meter at different
2 locations on our system that can't differentiate
3 between export type sales.
4 So -- and I think what Mr. Chernick is
5 trying to get at is to test the reasonability of that
6 assumption. And I think if I could dummy it down,
7 that would be what he's trying -- trying to get at.
8 And he's trying to ask what kind of data that we have
9 available that might provide some information to test
10 that assumption.
11 THE FACILITATOR: And -- and wouldn't
12 it be more helpful to us to have really the answer to
13 that question given back to -- to try and have
14 Manitoba Hydro's response in terms of, Well, here's
15 what we got, and here's why it's -- it's relevant to
16 the question, or -- or, We have a -- a fairly bald
17 simplifying assumption which we can't improve?
18 MS. KELLY DERKSEN: You know, here's
19 how I'll respond. And -- and that is getting back
20 sort of to the key themes again of this, and that is
21 how fine a point can we place on allocating cost to an
22 export class for purposes of what it's intended to do,
23 which is ultimately decide on class, domestic class,
24 cost responsibility.
25 And we've said it's very difficult to

1 pinpoint. It's not possible to pinpoint the costs
2 incurred, fixed costs incurred to pursue those sales.
3 And so we've made an overarching policy decision to
4 say, We're going to treat them on an equivalent basis
5 as dependable as compared to a domestic customer.
6 And if you accept that -- that judgment
7 call, then trying to drive a very fine point tuning,
8 which is some of what -- where Mr. Chernick wants to
9 test the assumptions, then that by inference means
10 that you don't accept the judgment call that Manitoba
11 Hydro has made.
12 And if -- and so that -- that's really
13 what the debate is, is -- is how fine a point do you
14 want to place on this? Is it -- you know, it's trying
15 to chase electrons and, you know, it becomes very
16 difficult.
17 And the -- the other challenge is, if
18 you assume, right or wrong, that the assumption that
19 we've made, which is dependable sales have the same
20 load characteristics as opportunity sales for purposes
21 of allocating fixed costs to dependable sales, if --
22 if you do that, I'm not sure that having data at
23 common bus versus generation is really going to draw
24 out a whole lot better information than what we have
25 because we simply don't know.

1 We can't differentiate between
2 dependable and opportunity and, you know, the -- the
3 challenge becomes, you know, how far down the path do
4 you want to go.
5 THE FACILITATOR: How far down the
6 path do you want to go, Paul?
7 MR. PAUL CHERNICK: Well, I -- I think
8 that the -- the first thing is just to find out what,
9 or when we've done different explanations, or at least
10 what I thought was -- was how they did the calculation
11 of the class contribution to the -- the CP loads.
12 That's been a little different here than -- than what
13 we've heard before, so I'd still like an explanation
14 of that.
15 And the second thing is that I think
16 that the Board should know how much difference it
17 makes, whether we're talking bout using the -- the
18 common bus or a generation load. And as I said, if it
19 doesn't make much difference then any approximation is
20 going to give you about the same result.
21 But if it makes a big difference, then
22 there's a real decision to be made as to do you treat
23 for this purpose of figuring out what your peaks are?
24 Do you count opportunity sales as if they were firm?
25 Or do you take out all the exports? Or do you look

1 for some other way of identifying the firm sales, like
2 billing records, rather than the metres at the -- the
3 border?
4 And as I said, maybe it's not something
5 that can be resolved finally in -- in this proceeding
6 but maybe it's a take-away for the Company to work on
7 until -- you know, and bring back a workable
8 methodology. Or maybe it's nothing because the hours
9 would be about the same between -- regardless of how
10 you sort them, and maybe there's not a lot of
11 difference within those hours.
12 THE FACILITATOR: Patrick, do -- are
13 you going to pile on, or come up with a solution for
14 us?
15 MR. PATRICK BOWMAN: I don't know. We
16 -- I just wanted to note. We have effectively the
17 same issue on tomorrow's list when we deal with
18 transmission where a lot of the fifty (50) top hours
19 issues arise, so -- but our question again, I think --
20 I think -- if it's helpful, I -- I hear Hydro's
21 responses dealing with -- very focused on how do you
22 deal with allocations to exports but I think Paul's
23 question, at least -- and I think certainly ours is --
24 is not just about exports.
25 It's about all the classes, and all the

1 class contribution when Hydro went to the fifty (50)
2 hours. If you look in one of the interrogatories we
3 asked, they -- they refiled one from -- from many
4 years ago when we went to fifty (50) hours. And what
5 they effectively said, when we're using one (1) hour,
6 if that peak happened -- the -- the peak for the year
7 in question happened to have happened in the middle of
8 the afternoon on a weekday, general service small
9 would get hit. And if it happened early morning while
10 everyone's having their showers, residential would get
11 hit. So we went to fifty (50) hours so we could pick
12 up this variability.
13 Well, that to -- to me, that means
14 there must be some set of data that says hour one (1)
15 has this breakdown among all the classes. Hour two
16 (2) has this breakdown among all the classes. And
17 somewhere down the line hour thirty-six (36) has this
18 set of breakdowns. And just to see those breakdowns
19 of all fifty (50) hours, whether you want to add up
20 the common buts or add up the generation, it -- it
21 would be helpful if you had that, too, because it
22 would make sense of the generation numbers.
23 But even among the classes, whether
24 those fifty (50) hours are -- how they break down
25 among the classes. If that doesn't exist, I -- I

1 don't know what else one is doing with fifty (50)
2 hours, if you know what I mean.
3 THE FACILITATOR: Thank you. And I --
4 I think maybe our best approach for this one because
5 it's a bit difficult is that it is going to come up
6 again tomorrow. Manitoba Hydro has a bit of
7 forewarning of what the -- what the issue is, and can
8 properly caucus for a little bit before tomorrow to
9 work on what -- what are the most appropriate
10 responses.
11 And -- and, Paul, in fairness to the
12 other times available and recognizing some people are
13 giving up some time, but could you try and deal with
14 your remaining things in five (5) or seven (7)
15 minutes, or so?
16 MR. PAUL CHERNICK: Okay. I thought I
17 had a little bit more than that.
18 MR. BILL GANGE: I thought, Mr. Grant,
19 that he had twenty (20) minutes left. He started at
20 twenty-five (25) after 1:00, and -- and he was
21 allocated an hour.
22 THE FACILITATOR: Oh, sorry, allocated
23 an hour?
24 MR. BILL GANGE: Yes, he was allocated
25 an hour. Yes.

1 THE FACILITATOR: Oh, my mistake.
2 Sorry.
3 MR. PAUL CHERNICK: Okay. Well, okay,
4 let's move onto the response to the Green Action
5 Centre's request fifty-seven (57). We asked for the
6 last five (5) years of data, and we got sort of the
7 last five (5) years as of 2011/'12.
8 Would it be possible to -- to actually
9 bring that up to date for the -- the last three (3) or
10 four (4) years?
11
12 (BRIEF PAUSE)
13
14 MS. KELLY DERKSEN: This is really
15 sort of just an extension of the same issue we've been
16 talking about. And we'll have to take it away and --
17 and sort through it in preparation of further
18 discussion tomorrow.
19 MR. PAUL CHERNICK: Okay. The -- the
20 next question I had on -- on our question 57 was that
21 the loads shown for February 2012 in that response
22 doesn't have the same time or the same load as the
23 highest common bus value in GAC-8 for February 2012.
24 And I wondered whether you could just
25 take that away and -- and explain what that difference

1 was?

2 MS. KELLY DERKSEN: We'll follow up

3 and see what we can respond tomorrow.

4 MR. PAUL CHERNICK: And also in fi --

5 the tables in response to our question 57, as -- as I

6 calculated it, if you add up the classes, not

7 including exports, you don't quite get the same thing

8 as the common bus. And I wondered whether there's

9 another category of load or whether this is a

10 difference between at the meter versus with losses at

11 the bus or basically why, if you look at attachment 1

12 for April of 2011, if you add up residential through

13 large GS it doesn't come up to the -- the common bus

14 value.

15 And that sounds like something that --

16 to me that would be appropriate from -- for an

17 undertaking. I wouldn't expect -- this is not a pop

18 quiz.

19 MS. KELLY DERKSEN: Well, I'll fail if

20 it is. Yeah, I can't -- I couldn't respond. We'll

21 have to --

22 MR. PAUL CHERNICK: I would be really

23 surprised if you could. Okay, on -- on our question

24 59, which the -- in the spreadsheet you provided some

25 -- some very useful detail in the derivation of the

1 line losses, but those calculations seem to start with
2 some assumptions that -- distribution losses are 1.6
3 percent greater than average for the residential
4 class, for example, and less than average for other
5 classes and that losses are 1.5 percent for the 30 to
6 a hundred KV GSL class.
7 Would it be possible to get an
8 explanation of where the input assumptions in that
9 spreadsheet come from? And again, I don't expect
10 anybody to just know it off the top of their head.
11 MS. KELLY DERKSEN: The best I can
12 offer to you, Mr. Chernick, is it's likely a study
13 from sometime in the 1990s which we don't have --
14 MR. PAUL CHERNICK: Okay.
15 MS. KELLY DERKSEN: -- access to
16 anymore, a line loss study. And that is the -- the
17 derivation of -- of those numbers, and they have not
18 been updated since that time.
19 MR. PAUL CHERNICK: Okay.
20 MS. KELLY DERKSEN: And, you know, in
21 terms of order of magnitude, I don't know, losses
22 might be, you know, 1 percent or, you know, it -- it's
23 fairly small.
24 MR. PAUL CHERNICK: That's certainly
25 not the biggest issue in -- in the case. And I guess

1 my last question for today is -- and this is one (1)
2 of those costs that moves back and forth between
3 transmission and -- and generation, so we could talk
4 about it either day.
5 Ancillary services like load following
6 are -- that's something that's used every hour, and
7 yet you -- as I understand it, you -- you're rolling
8 those in with transmission and allocating them on the
9 -- the 2CP.
10 And I wondered whether we could get an
11 explanation of why ancillary services would be related
12 to peak rather than to dispatching all of this energy.
13 MS. KELLY DERKSEN: We actually have a
14 number of ancillary services. We've broken them down
15 and discussed them briefly in our cost-of-service
16 study. Most of those, like you -- like you state, are
17 related to the generator. We have not separated that
18 from the generation function.
19 Those ancillary services, with the
20 exception of system dispatch and control, are
21 allocated based on generation which is based on a
22 weighted energy allocator system. Dispatch and
23 control is part of the transmission function, and you
24 point out that it's -- it -- it is allocated on a 2CP
25 basis.

1 MR. PAUL CHERNICK: Okay. So maybe I
2 -- I got the lists mixed up. So you're saying only
3 the -- the transmission dispatch and control is -- is
4 in the transmission costs?
5 MS. KELLY DERKSEN: In the
6 transmission function, yes, allocated on a 2CP basis.
7 MR. PAUL CHERNICK: Okay. All right.
8 And I think that takes care of my questions for today.
9 Thank you.
10 THE FACILITATOR: Thanks very much.
11 Let me just look at the schedule here to see where we
12 are. It's -- my understanding is that the General
13 Service Consumers and the City of Winnipeg are going
14 to likely share their questioning. And then we would
15 be on to the -- the Board's consultant and the panel.
16 Would our best -- why don't we get
17 started for a while here and make a go, hopefully to
18 finish your questioning by about three o'clock and
19 take the break then rather than now. Does that sound
20 good?
21 MR. CHRISTIAN MONNIN: Sorry, are you
22 looking at me for general service?
23 THE FACILITATOR: Yes, sorry.
24 MR. CHRISTIAN MONNIN: Okay. I'm just
25 looking at -- at the schedule. After Green Action

1 Centre would be us. It might be more convenient if we
2 were to jump upon the queue or get up on the front --
3 front benches here.
4 THE FACILITATOR: Right.
5 MR. CHRISTIAN MONNIN: And if doing
6 that, that might be the appropriate time for a break.
7 But I'll -- I'll leave it to you.
8 THE FACILITATOR: All right. Why
9 don't we just take a ten (10) minute break while that
10 occurs? Thank you.
11
12 --- Upon recessing at 2:17 p.m.
13 --- Upon resuming at 2:31 p.m.
14
15 THE FACILITATOR: All right. I think
16 we're ready to go, so over to the General Service guy.
17
18 QUESTIONS BY GENERAL SERVICE CONSUMERS:
19 MR. CHRISTIAN MONNIN: Good afternoon.
20 My name is Christian Monnin, and I'm legal counsel for
21 the Gen -- General Service Customers. And we have our
22 consults here, London Economics International. To my
23 extreme right is Mr. Jarome Leslie and Mr. Ian Chow.
24 Mr. Leslie will be asking the majority
25 of the questions today and Mr. Chow might chime in.

1 And to the benefit of the whole process and all those
2 involved, I will not be asking any questions.
3 There was some discussion yesterday
4 between Manitoba Hydro and general service customers
5 with respect to some pre-asks that were filed. My
6 understanding is that we've come to an agreement. We
7 will be working through those pre-asks. To the extent
8 that they can be answered today in real time that will
9 be done. To the extent they can't they'll be done --
10 be undertaken as per the order.
11 In addition, there may be some
12 additional questions that have arisen based on the
13 deliberations of today and those will be asked. We do
14 not anticipate we'll take the full thirty (30)
15 minutes. Therefore, if other -- and Intervenors have
16 some questions to follow-up on or -- certainly they're
17 welcome to do so. I'll pass this over to Mr. Leslie.
18 Thank you.
19 MR. JAROME LESLIE: Thank you,
20 Christian. I think a good place to start would be
21 with Manitoba Hydro's slide back today, slide number
22 28. And here Manitoba Hydro builds to serve domestic
23 load. We see that the surplus energy is used to fill
24 it and dep -- dependable export to -- from contracts
25 and opportunity sales as well.

1 So in relation to -- to this my
2 question is, during the planning stage of generation
3 investment what consideration is made in regards to
4 opportunity exports and the assessments of the -- of
5 the project viability? And, I guess more
6 specifically, is there a certain target in main --
7 maintaining a certain energy surplus in terms of
8 getting those export -- maintaining certain export
9 revenues?
10 MR. TERRY MILES: Well, I'll take this
11 one (1). So if I understand your question, you talked
12 about opportunity exports and you talked about then
13 some of the surplus dependable exports. And I'm going
14 to assume that your question is around the surplus
15 dependable exports in -- in terms of how much might we
16 try to maintain a surplus dependable for firm export
17 contracts.
18 Is that your question?
19 MR. JAROME LESLIE: Yes, it's -- is
20 does Hydro in its planning seek to maintain a certain
21 target? Also, is this something that is acti --
22 actively considered in the timing of these generation
23 investments?
24 MR. TERRY MILES: So we -- we plan to
25 serve Manitoba loads. Ultimately our -- our goal is

1 to meet the needs of -- of Manitoba, recognizing that
2 depending on the type of resources that we build, as
3 shown on the chart, they can be built in lumps. So
4 you -- you add a -- add a resource that -- that's
5 larger than the Manitoba load requirement. And then I
6 think Mr. Cormie indicated then that the Manitoba load
7 would grow into that -- that resource. So given the
8 type of resource, however much surplus there might be
9 from that, and however long of a period it takes for
10 the Manitoba load to catch up with that then that
11 would be available for an -- for an export.
12 Do we have a target that says we will
13 try to maintain a certain amount of -- of surplus over
14 time? Not specifically, no. Advancing resource,
15 either building resource in advance of Manitoba load,
16 that would -- that consideration would be based on
17 economics of doing that. And that would vary,
18 depending on the circumstances at the time.
19 MR. IAN CHOW: So when we talk
20 advancing the -- a construction ahead of Manitoba
21 load, can you talk a little bit about what sort of
22 factors you -- you use to determine how far in advance
23 you do do the build?
24
25 (BRIEF PAUSE)

1 MR. DAVID CORMIE: There is no value
2 in -- in advancing the installation of new resources
3 just to serve Manitoba load. Because, as -- as Mr.
4 Miles say, we -- we are -- when we run out we run out,
5 and we have to have new resources on that date. But
6 if you want to salvage some of the value of the large
7 block in surplus it has to have value to an external
8 customer. And if -- if the -- if they needed a supply
9 for ten (10) years and you only had surplus dependable
10 for eight (8) years, you might want to advance the
11 plant two (2) years to -- to turn it into a product
12 that your customer could use as an alternative to
13 building his own supply.
14 And so that was the case with the
15 decision to Keeyask. We advanced it several years in
16 order to salvage that block of surplus that was -- was
17 available. And -- and you found -- we found an
18 offtaker who was willing to not build and pay Manitoba
19 Hydro an alt -- an equivalent price. If you didn't do
20 that then you would just end up having surplus energy,
21 and whether it was dependable or not the market
22 wouldn't care and you would just get this -- get --
23 you'd get the opportunity sale. But -- but by
24 advancing a plant we can then work with a customer so
25 that it brings value to him, and at the same time

1 salvaging value for Manitoba Hydro.
2 So it's -- it's more about can you go
3 to the market and find somebody who's willing to do
4 that, and they may say, well, you need -- it -- it has
5 to be win/win so you need to adjust your -- adjust
6 your plant timing. But we can never delay it, but we
7 -- we can advance it.
8 MR. IAN CHOW: Understood. I think
9 the follow-up question to that is: Do the opportunity
10 -- did the opportunity exports play a part in -- in
11 advancing the -- the construction at all?
12 MR. DAVID CORMIE: Well, the
13 opportunity -- the opportunity revenues will slightly
14 affect the economics because you've got -- you've got
15 some additional non-dependable surplus that can gen --
16 will generate some revenues, but there's -- there's
17 uncertainty what that value will be, as opposed to the
18 firm sale which is going to be at a fixed price and,
19 you know, it -- there's no uncertainty of what that's
20 going to be.
21 So there is a -- there's -- because
22 you're building it a little earl -- bit earlier you're
23 attracting a long-term firm sale, and you're
24 attracting then some additional revenues from the
25 opportunity market for the surplus that that plant

1 might -- might provide.
2 So all those things are considered when
3 we're looking at developing sequences, and -- and, you
4 know, the additional opportunity revenue, the
5 additional firm sale revenue that you can attra --
6 that you can attract all go into the economic
7 calculation to determine which sequence -- the Delton
8 (phonetic) sequence provides the least long term cost
9 for -- for Manitobans, remembering that this asset
10 will be in place for a hundred years.
11 And really all we're talking about is,
12 you know, can you adjust the upfront timing and -- in
13 order to make it economically -- most economically
14 attractive to Manitobans.
15 MR. JAROME LESLIE: Okay. Thank you.
16 And on a related note, based on some of the discussion
17 that took place earlier today the first Intervenor
18 segment from MIPUG touched on the treatment of thermal
19 generation allocation. And the discussion revolved
20 around the handling of coal and you made the point
21 that it's not necessarily used to buy exports.
22 So you also mentioned certain extreme -
23 - certain extreme situations that gas generation could
24 be used to back either domestic load or dependable
25 firm sales. So I was wondering to what extent is that

1 the case of -- in terms of the frequency of the
2 occurrence of such events? If you could speak to
3 that?
4 MR. DAVID CORMIE: The -- the
5 frequency is -- comes from our energy planning
6 criteria, which means that we have to have sufficient
7 energy resources available in the worst historic river
8 flow year -- water flow year. So we have a hundred
9 and four (104) years of water flow records, and we
10 design against the worst in that hundred and four
11 (104) year sequence.
12 So the frequency is about, you know,
13 one (1) in a hundred (100) approximately. That's the
14 type of frequency in which all dependable resources
15 would be used to serve -- to -- to serve load.
16 MR. IAN CHOW: So you speak to it as
17 one (1) in a hundred (100) years. In the last hundred
18 years plus twenty (20) years, say, has -- have natural
19 gas resources been used to back exports -- dependable
20 exports? Have -- has that situation arisen?
21 MR. DAVID CORMIE: Well, the -- the
22 last drought we had was in 2003/'04, and that was a
23 one (1) in thirty (30) year event. In that event, we
24 were able to meet almost all our non-hydro energy
25 needs by purchasing energy in the market.

1 Had the drought been a little bit more
2 severe with a -- with a lower frequency, at that point
3 we would have exhausted our ability to buy in the
4 market and import power, and at that point we would
5 have had to baseload our combustion turbines. That
6 didn't happen in that year, so we haven't had a
7 drought yet that has tested the design capacity of the
8 power system.
9 We -- because Manitoba Hydro didn't
10 exist as an entity back in 1940/'41, which is the
11 historic flow year, but -- but all we used is the --
12 we used the historic record as an indicator as the
13 possible types of river flows we can face in the
14 future. And we're not -- we're just saying, well,
15 that flow year can occur any time. And we plan for
16 the worst case occurring in each and every year in the
17 future. And we're prepared to serve load under all
18 those circumstances in every load year as we go
19 forward.
20 MR. JAROME LESLIE: Okay, thank you.
21 The next question I'd like to move on to, it touches
22 on Pre-Asks 1 and 8. So in order to properly
23 understand the appropriateness of allocating fixed and
24 variable costs to the different export types we had
25 asked for you to provide data on historical and

1 forecasted export data, historical simply for the last
2 ten (10) years, and then looking forward for the next
3 -- as far as your forecasts and the data was available
4 to provide.
5 And from what we've seen, and they are
6 responses, you've provided some data already. We've
7 seen the historic on-peak -- on-peak export sales. So
8 we wanted to refine our request to ask you to provide
9 those sales across all hours of the year versus just
10 the on-peak export sales.
11 And I believe -- well, the reference
12 for that would be -- would be Coalition 57C. And do
13 you have the historical export sales from 2005 through
14 to 2014? So if you have the data available to expand
15 those on-peak sales to total hours for the -- for
16 those years?
17 MS. KELLY DERKSEN: I'll -- I guess
18 I'll start here. Someone -- Mr. Cormie may have to
19 help me out. With respect to hybrids, we won't have
20 that data. That's a new issue --
21 MR. JAROME LESLIE: That -- that's
22 fine.
23 MS. KELLY DERKSEN: -- for us. With
24 respect to dependable and -- and opportunity, I -- I
25 think I'm hearing you ask about energy or energy at

1 peak periods. We're going to have to sort through
2 what we -- what we have available, I -- you know, and
3 also data that has already been made available on the
4 record. I suspect there are bits and pieces of it,
5 but I don't have that immediately at my fingertips.
6 MR. JAROME LESLIE: Could you do that,
7 take that in undertaking for the historical export
8 sales for all hours?
9 MR. DAVID CORMIE: There is a response
10 to a PUB IR that shows the dependable and opportunity
11 export breakdown for back since the MISO market opened
12 in 2005, and I'll get you that reference in a few
13 minutes.
14 And, as Kelly said, our -- the only
15 hybrid sale that we've entered into began on May the
16 1st of 2015. So there is no historical data prior to
17 that. So I think --
18 MR. JAROME LESLIE: That's -- that's
19 fine, yeah.
20 MR. DAVID CORMIE: And -- and another
21 issue, and -- and you could see it in that wedge, you
22 know, that drawing that we were looking at before,
23 that looking back tells you where you came from, it
24 doesn't tell you where you're going to go.
25 And, you know, it's kind of -- if you -

1 - if you were in the middle of this -- of the -- of
2 the dark or -- orange wedge, you could look back and
3 see what surplus you have. They're not -- they're not
4 an indicator of what you're going to have in the
5 future. And so, you know, it's -- it may not be that
6 helpful in -- in looking at the historical data to
7 tell you what you expect.
8 But Ms. Derksen has -- has shown us a
9 table a few minutes ago that said this is what
10 Manitoba Hydro's forecasting, the breakdown between
11 opportunity and dependable sales on a go-forward
12 basis, and you saw that ratio was around 45 to 50
13 percent was the number. And so the number really --
14 that -- that will re -- that's kind of the average,
15 and some years it'll be more than that, some years
16 less, because of -- of water conditions.
17 Historically, if you look back in the
18 last ten (10) years, we've been in a high water
19 period, and so opportunity sales are about 66 percent
20 of our sales volumes and a third are dependable, but
21 that's because we've been in a wet cycle.
22 So on a go-forward basis, when you just
23 assumed the average of all flows, those are the ratios
24 that you would get. So maybe that would be helpful in
25 understanding or as -- as an -- as a response to this

1 question.
2 And I'll -- I'll found out the
3 reference here to that historic table and get it to
4 you in a minute.
5 MR. JAROME LESLIE: Oh, thank you.
6 Yes, I think that would be helpful.
7
8 (BRIEF PAUSE)
9
10 MR. JAROME LESLIE: My next question
11 is related to the treatment of exports and export
12 revenue. So -- oh, sorry. It's more specifically
13 towards the trading desk and MISO membership costs
14 allocated to opportunity exports. And this is related
15 to Pre-Ask-9.
16 So in PUB IR number 14, Hydro describes
17 the rationale of splitting these trading desk and MISO
18 membership costs between domestic and export classes.
19 And in the IR, it's deemed to be 58 percent domestic
20 and forty-two (42) to the export classes.
21 And one (1) question related to this
22 is: Given that this split is based on 2009 analysis,
23 how -- we're asking if you can update this analysis to
24 confirm whether this -- the deemed split is still
25 representative of the situation now, and whether or

1 not it's something that you can confirm.
2 MS. KELLY DERKSEN: I haven't done the
3 analysis. I -- my -- my expectation is we wouldn't
4 see a significant change in that. And the dollars
5 that those percentages would be applied to aren't
6 significant. So it becomes a question of -- of
7 materiality.
8 That said, we've moved away from using
9 these splits in PCOSS14 amended. We've applied
10 trading desk costs and MISO costs on a proportional
11 basis as we've talked with Mr. Harper. And how we've
12 gone about and -- and done that is, you know, there's
13 information on how we've done that, both in our
14 submission as well as in a number of Information
15 Requests.
16 We've, you know, basically
17 proportionately based -- based it on weighted energy,
18 we have split that, then, between domestic customer
19 classes as well as export -- export sales, and in this
20 case, both dependable and opportunity. So we haven't
21 done -- updated the analysis simply because we've
22 moved away from it.
23 MR. JAROME LESLIE: Okay. In relation
24 to Pre-Ask 10, this is on the basis of the net revenue
25 allocation. And on page 18 of Hydro's cost-of-service

1 methodology review submission, you state that the
2 reven -- net export revenue allocation is based on
3 total costs.
4 However, in our review of the model, we
5 are seeing that the allocation is based on total costs
6 less direct costs. So I just wanted to get some
7 clarity on the -- your position on net revenue
8 allocation and whether direct costs are excluded from
9 determining the allocation shares.
10 MS. KELLY DERKSEN: Yes. You --
11 you're correct. Direct costs are excluded from the
12 allocation of net export revenue.
13 MR. JAROME LESLIE: And as part of
14 their -- the reasoning for exclusion, could you
15 provide some -- some justification or some operation
16 of -- on why that's the case?
17
18 (BRIEF PAUSE)
19
20 MS. KELLY DERKSEN: It essentially
21 amounts to the fact that we have certain customers on
22 our system that have infrastructure in place that is
23 really akin to dedicated end-use equipment,
24 facilities, and not a whole lot different than a -- a
25 fridge or a stove in a customer's home.

1 And because we define the point where
2 service -- service starts and stops at -- at the
3 metre, we've said it's appropriate to exclude those
4 kinds of costs for a certain customer class.
5 And in particular, the area and roadway
6 lighting class has street lighting infrastructure,
7 direct-assignment costs that are excluded in -- in the
8 determination.
9 MR. JAROME LESLIE: Okay. So my
10 follow-up to that would then be, on a going-forward
11 basis, is the consideration of what costs are
12 funnelled through to the direct -- or the allocation
13 of whi -- the decision on which costs are assigned
14 directly versus the ones that flow through the cost-
15 of-service allocation in -- in regards to area
16 lighting, as regards to other domestic classes as
17 well.
18 How -- how is this -- how is this
19 handled, essentially?
20
21 (BRIEF PAUSE)
22
23 MS. KELLY DERKSEN: Net export revenue
24 today, and has been for quite some time, has been
25 allocated on the basis of each class's total allocated

1 cost, which means excluding direct assigned costs, but
2 in -- in particular related to dedicated end-use
3 plant. That portion of the investment of those
4 facilities is excluded from the calculation on the
5 basis that, you know, the -- the residential customer,
6 for example, wouldn't be assigned net export revenue
7 on the basis of the -- you know, the -- the type of
8 equipment that they have at their property.
9 So we have cut it off at -- at the
10 point that says total allocated costs, which means
11 costs allocated on account of generation,
12 transmission, sub-transmission distribution, and
13 whatever each class's allocation of those costs are is
14 how, then, net export revenue gets applied. So, for
15 example, if total allocated costs for the residential
16 customer class is 60 percent of -- of total allocated
17 costs, they would get 60 percent of the net export
18 revenue.
19
20 (BRIEF PAUSE)
21
22 MR. JAROME LESLIE: Okay. Okay.
23 Thanks -- thank you for that response. So the -- I
24 believe it also speaks to my second question, which
25 would be reconciling the share of net revenue

1 allocation to the share of total costs. Because when
2 you say total costs, you look at allocated in addition
3 to direct -- in addition to direct -- assigned costs.
4 So you're saying that the share of allocation -- the -
5 - the share of allocated costs is what, essentially,
6 matches the share of the export revenue. I just
7 wanted to confirm that.
8 MS. KELLY DERKSEN: Yes.
9 MR. JAROME LESLIE: Thank you. And in
10 -- again, in your methodology review submission, you
11 mentioned that weight is given to fairness and
12 efficiency objectives. This is in addition to a
13 consideration of the allocated cost shares.
14 So I was wondering -- I was -- could
15 you elaborate on those fairness and efficiency
16 objectives that are also considered?
17 MS. KELLY DERKSEN: Are you asking in
18 terms of how we allocate net export revenue?
19 MR. JAROME LESLIE: Yes. Is there
20 something over and above the share of allocated costs?
21 MS. KELLY DERKSEN: Well, let's step
22 back here for a moment, and let's talk about why we
23 are where we are. And, you know, the whole issue that
24 precipitated, if you will, an export class a decade or
25 more ago is because we were -- we were generating

1 revenue in -- in the export market that exceeded, to a
2 sign -- significant degree, embedded cost of Manitoba
3 Hydro. And as that export revenue was growing and
4 embedded costs were either flat or declining, the
5 treatment that was applied at the time was
6 disproportionately benefiting certain customer classes
7 in comparison to others.
8 And -- and the real issue is that you
9 are incorporating, basically, marginal costs into an
10 embedded cost-of-service study. And, you know, those
11 things at the best -- you know, are at -- at odds with
12 each other. And so it was causing issues from a
13 domestic cost responsibility perspective in terms of
14 the sharing that -- in terms of the sharing of those
15 revenues and -- and ultimately, allocated cost. And
16 so because of that fairness issue, and -- because all
17 else being equal, if you set your cost of service on
18 the basis -- or if you set your rates on the basis of
19 cost of service, you encourage or discourage
20 consumption.
21 And if consumption is occurring for
22 some customer classes at a much greater pace than --
23 than other customer classes, all else being equal, the
24 system need -- we need an increase in revenue
25 requirement in order to support that cost allocation

1 issue, even though there was no change in your
2 embedded cost. And this what was -- this was the
3 issue that was -- that gave rise to the export class
4 treatment in the first place.
5 And so we landed with an export class
6 back then to say, let's assign some embedded cost
7 responsibility against the export class such that once
8 you have assured yourself that they have reasonably
9 contributed to the fixed costs of the system,
10 notwithstanding that you don't build the system for
11 exports, you can comfortably say, then, the residual
12 that's left can be applied to customer classes on the
13 basis of something other than the assets that gave
14 rise to that revenue in the first place.
15 And so that was an issue of -- of
16 fairness. Now, going down the path of, Do you include
17 dedicated and used facilities, which is really what
18 the -- the question is that you're asking, and whether
19 -- you know, how that comports with this -- this whole
20 issue of fairness to begin with is -- it's not a bad
21 question.
22 And the -- the challenge becomes if you
23 include those costs for certain customer classes, but
24 for other customer classes, they don't get that
25 benefit, because -- because it -- it's a -- we don't

1 look at it from a dedicated end-use perspective for
2 residential customers, for example, then you're a bit
3 dis -- you're disconnected between the customer
4 classes.
5 Now, I suppose there's a fair argument
6 to say, you know, what this is all about is a fairness
7 issue at the end of the day, in any event, so I
8 suppose one could make the argument to extend the
9 application to dedicated end-use facilities also. We
10 stopped it at the point of delivery, which is the --
11 really just the metre, and we've said that that is
12 reasonable.
13 MR. JAROME LESLIE: Okay. Thank you
14 for the response. That was actually the -- our last
15 question. Turn it over to --
16 MR. DAVID CORMIE: Mr. Leslie, I have
17 the answer for the undertaking. If you look at
18 Coalition-58A, there's a table of on-peak sales
19 broken down between the dependable and the opportunity
20 classifications. If we can bring that up?
21 And you can see since 2005 through
22 2014, the number of gigawatt hours that have been sold
23 on a dependable basis goes down from 3.7 terawatt
24 hours to two point seven (2.7), and that's gradually
25 going down because Manitoba firm load is gradually

1 going up.

2 But the generating capability of the

3 power system is remaining relatively constant. So

4 you'll see that the opportunity sales volume is

5 gradually increasing. The sum of the two (2) is about

6 -- you know, on average, it's around 5 1/2 terawatt

7 hours. And we're shifting more and more sales into

8 the opportunity market as opposed to the -- the firm

9 sale.

10 So that -- there -- there's the history

11 that you had asked for, and I hope that's useful.

12 MR. JAROME LESLIE: Yes. So we noted

13 that you did provide this history of on-peak sales, so

14 that our question was whether this could be extended

15 to sales across all hours, if this same version of the

16 table could be extended for all hours?

17

18 (BRIEF PAUSE)

19

20 MR. DAVID CORMIE: I'm sure we have

21 the response. I'll have to look for that one, as

22 well.

23 MR. CHRISTIAN MONNIN: Well, then

24 we'll take that as an undertaking, then. That wraps

25 up our time. Thank you for the opportunity and thank

1 you for your time for the Manitoba Hydro -- Hydro
2 panel.
3 THE FACILITATOR: Sean has asked that
4 for undertakings, if you can specifically state the
5 undertaking that you'd like. And Manitoba Hydro can
6 respond, that they'll address it as best they can.
7 Then we'll have that on the record for the
8 undertakings.
9 MR. JAROME LESLIE: For our
10 undertaking on this issue, could you provide a
11 schedule of historic export sales from 2005 through to
12 the 2014 year for all hours and -- and a similar
13 schedule to the one provided in -- in the table shown,
14 Coalition 58A? And, also, can you provide the
15 forecasted export sales looking forward in a similar
16 table?
17
18 (BRIEF PAUSE)
19
20 THE FACILITATOR: Sorry. And that's
21 one, I take it, that you're going to give as best a
22 response as you can to when you can. Thank you.
23
24 --- UNDERTAKING NO. 5: Manitoba Hydro to provide
25 a schedule of historic

1 export sales from 2005
2 through to the 2014 year
3 for all hours, and a
4 similar schedule to the
5 one provided in the table
6 shown in Coalition 58A,
7 and provide the forecasted
8 export sales looking
9 forward in a similar table
10
11 THE FACILITATOR: John Todd, does that
12 cover the areas that you wanted?
13 MR. JOHN TODD: Yes.
14 THE FACILITATOR: Then I think we're
15 on to the Board's consultant, Daymark. Are -- are you
16 guys going to want to work from there, or...? Okay.
17
18 (BRIEF PAUSE)
19
20 QUESTIONS BY BOARD CONSULTANT (DAYMARK):
21 MS. MARY NEAL: Can you hear me? Yes.
22 Okay. So this is Mary Neal, from Daymark, energy
23 advisors. Before I get started into the questions, we
24 filed some questions yesterday in writing. The first
25 fifteen (15) of those questions were labelled as

1 requests for documents. And it's our hope that we
2 don't have to go through all of those in the workshop,
3 because it would just take up a lot of time, and it's
4 mostly just asking for more numbers.
5 I don't know if Manitoba Hydro's had a
6 chance to look at that or has any response to that.
7 MS. KELLY DERKSEN: Not in any
8 detailed kind of way. We haven't had a chance to look
9 at it.
10 MS. MARY NEAL: Okay. So maybe we
11 could follow up on that. To start, I have a simple
12 question on... So there was a revised model filed on
13 April 25th in response to one (1) of the IRs. And I
14 believe in that IR, it referenced the change to the
15 weightings, for the weighting -- weighted energy
16 allocator.
17 And is that the only change that was
18 made in that model compared to the one that was filed
19 earlier on the March 11th?
20
21 (BRIEF PAUSE)
22
23 MS. KELLY DERKSEN: If we're talking
24 about the version that we provided at the end of
25 March, it's my understanding that what we provided is

1 just additional flexibility in terms of allowing one
2 to adjust the weighted energy allocators, but not the
3 data itself.
4 MS. MARY NEAL: Okay. But there's no
5 other changes, like...?
6 MS. KELLY DERKSEN: Subject to check.
7 MS. MARY NEAL: Okay. If we could
8 talk a little bit more about the weighted energy
9 allocator. So there's two (2) versions, one (1) that
10 has energy volumes for total exports and one (1) that
11 has energy volumes for just dependable energy firm
12 sales.
13 Could you clarify for me the -- the
14 total energy volume of kilowatt -- the total kilowatt
15 hours used in the allocator -- that includes the total
16 kilowatt hours -- where that comes from? Is that
17 based on actual data, actual export sales data?
18 Because I believe when you were talking to Mr.
19 Chernick, you mentioned it being actual data.
20
21 (BRIEF PAUSE)
22
23 MS. KELLY DERKSEN: Talking about the
24 same thing. We are -- we -- we use forecasted data,
25 not actuals.

1 MS. MARY NEAL: So that's forecasted
2 total kilowatt-hour sales?
3 MS. KELLY DERKSEN: Yes.
4 MS. MARY NEAL: Okay. And that
5 forecast is supposed to rep -- reflect median water
6 conditions? That's correct?
7 MS. KELLY DERKSEN: Yes.
8 MS. MARY NEAL: Okay. And then the
9 dependable portion, that's also based on a forecast,
10 how you determine that?
11 MS. KELLY DERKSEN: That's right.
12 MS. MARY NEAL: Okay. Thank you for
13 clarifying that.
14
15 (BRIEF PAUSE)
16
17 MS. MARY NEAL: Talk a little bit more
18 about the weighted energy allocator. So it's my
19 understanding that you rely on load research to
20 determine the allocation of the total annual energy to
21 the different time periods, including exports, those
22 twelve (12) different time periods.
23 So when -- thinking ahead to when
24 Keeyask comes online, we know that the exports will be
25 different. Is there any concern about being in a

position where Keeyask is in service but you don't have load research data to know how that's going to affect the exports? Will you be using old data, or have you thought about that?

MS. KELLY DERKSEN: We haven't thought that far ahead there -- there. You know, there will be an issue. We won't have actual data to rely on, obviously, for a new plant, but we are not advanced enough in our thinking to know, you know, how we will apply forecast of energy sales in the year that that facility comes on line.

MS. MARY NEAL: Okay. Thank you.

(BRIEF PAUSE)

MS. MARY NEAL: Okay. Moving to a question about the allocation of net export revenues, Manitoba Hydro has expressed concern about fairness and trying to allocate costs in such a way that we don't end up with the rates below -- significantly below marginal costs.

So the question is: If we went back to a method of allocating net export revenues or total export revenues, even, on a allocation of a generation and transmission cost basis only, given today's export

1 market and the current prices that we're seeing, would
2 that still be a concern? Would -- would rates still
3 end up below marginal cost?
4
5 (BRIEF PAUSE)
6
7 MS. KELLY DERKSEN: Is the issue as
8 pronounced as it once was? The answer is likely not
9 as pronounced. I anticipate that there are -- would
10 still be issues, and it certainly doesn't address what
11 happens when Keeyask comes online and you have a sig -
12 - signifi -- significant more energy presumably being
13 sold as exports.
14 So today, if the question is, Would you
15 create the same methodology in circumstances today,
16 probably not. But we have a challenge from -- from
17 the perspective that we want to provide at least some
18 stability in terms of your allocation methodology, and
19 certainly recognizing you've got very -- a -- a very -
20 - just a couple of years from now you'll have another
21 large infrastructure in place. And potentially we
22 could be back in the -- in the same circumstance to a
23 much greater extent then.
24 So the -- you know, the challenges ha -
25 - well, if I say it in a different -- in a different

1 way the question is: Is your methodology today robust
2 enough to withstand the variety of circumstances that
3 we can experience? And -- and in our view, we think
4 it is. We think it's a -- a reasonable way to -- to
5 handle, you know, just fairly dramatic changes that we
6 can see in our system.
7 MS. MARY NEAL: Okay. That's helpful.
8 But just to be clear, you don't have any specific
9 quantitative analysis that actually analyzes that
10 issue?
11 MS. KELLY DERKSEN: We have lots of
12 analysis.
13 (BRIEF PAUSE)
14
15 MS. KELLY DERKSEN: In terms of
16 whether there are any customer classes whose embedded
17 costs fall below short-run marginal costs today, I
18 don't believe we do. But again, it was more than just
19 that issue. It was the degree of variability between
20 the customer classes. And if you were to return to an
21 allocator based on generation and transmission,
22 assuming you would assign variable costs only to -- to
23 ex -- against exports, it -- I would expect that you
24 would still have some -- some issue. And I think in
25 our slide materials this morning, although I didn't

speak to it...

(BRIEF PAUSE)

MS. KELLY DERKSEN: Slide 39. That really gives you a -- a pretty good depiction as to the variability that one can experience with the application of the export revenue with allocating export revenue on the basis of generation and transmission only. And so that gives you some sense of the -- the volatility that can be experienced with that kind of circumstance, even in today's conditions.

MS. MARY NEAL: Okay. Thank you. If we could bring up the response to IR-PUB-63. There's a table in that.

(BRIEF PAUSE)

MS. MARY NEAL: So our understanding is this table does not include any indirect costs? Is that correct?

(BRIEF PAUSE)

MS. KELLY DERKSEN: I'm not sure how

one defines indirect costs. It is fully loaded from the perspect -- from the...

(BRIEF PAUSE)

MS. KELLY DERKSEN: I'll approach it this way. The cost that are identified in this undertaking with respect to DSM and purchase power, if you view that as an indirect cost those costs have been excluded. Everything else has been included.

MS. MARY NEAL: We were talking earlier about certain costs but you said you couldn't -- like common costs -- common generation costs you couldn't allocate to specific assets. Are those costs included?

(BRIEF PAUSE)

MS. KELLY DERKSEN: It's a fair comment to say that we don't typically look at fully loading up and individual assets like we have done, but in this case for this undertaking we did do that.

MS. MARY NEAL: You did?

MS. KELLY DERKSEN: Yes.

MS. MARY NEAL: Okay. Could you

1 provide an indication of the magnitude of those --
2 those costs for -- for that -- for that table?
3 MS. KELLY DERKSEN: I'm sure -- I'm
4 sure we could either directly or indirectly impute
5 what it would be. We know what our total allocated
6 generation costs are. We know what we've excluded,
7 and by process of elimination you would know -- I
8 think -- I think you would be able to -- to back into
9 the calculation one way or the other, I think.
10
11 (BRIEF PAUSE)
12
13 MS. MARY NEAL: I guess my -- my
14 concern is if you did have to allocate those costs in
15 some way, we'd like to know how that was done.
16 MS. KELLY DERKSEN: We most certainly
17 had to allocate them. They are indirect costs. We've
18 made some assumptions if -- if that's your question,
19 and how you apply those indirect costs to each of the
20 generating facilities in the question, and we've made
21 some assumptions to do that. We don't typically do
22 that. And we could provide generally how -- how we
23 did that, if -- if that's helpful to you.
24 MS. MARY NEAL: So you would like to
25 do that as an undertaking?

MS. KELLY DERKSEN: Well, I wouldn't really like to do that as an undertaking but if you're asking if -- if --

MS. MARY NEAL: I would like the information, so if you're not prepared to talk about it here, undertake to do that --

MS. KELLY DERKSEN: Yeah, I -- I can't do it on the fly here but we could prepare it, yes.

THE FACILITATOR: That --

MS. MARY NEAL: Okay. So --

THE FACILITATOR: -- could you state the -- the question then that --

MS. MARY NEAL: So we would like to know I guess two (2) things. One (1) is for this response to PUB-IR-63, how indirect costs were allocated to each of the generating assets and what assumptions were made to do that, and what portion of the total cost shown in column 8 is indirect cost.

--- UNDERTAKING NO. 6: Manitoba Hydro to provide how indirect costs were allocated to each of the generating assets and what assumptions were made to do that, and what portion

1 of the total cost shown in
2 column 8 is indirect cost
3
4 MS. MARY NEAL: And I think that's all
5 I have, but I can turn it over to my esteemed
6 colleagues.
7
8 (BRIEF PAUSE)
9
10 MR. DANIEL PEACO: Is this on? Can
11 you hear me? Okay. My name is Dan Peaco, and I'll
12 bat second here today. I'd like to start -- I'd like
13 to ask a few follow-up questions on the -- the
14 robustness discussion you had with Ms. Neil a few
15 minutes ago.
16 There are a few places in your
17 submission that you talk about robustness but given
18 the -- the -- it's -- it's raised in a similar
19 context, and the first question I'd like to ask is a
20 follow up to -- Mr. O'Sheasy, I think, talked earlier
21 about the period of time of interest that we've been
22 looking at this, and the discussion in the context of
23 short arm versus long arm marginal cost and the period
24 of time that we're really designing this cost of
25 service study for.

1 Could you tell me what -- sort of
2 numerically what -- what period of time you believe
3 that is? Is that between now and the time Keeyask
4 comes online? Some longer period of time? What --
5 what kind of a time frame do you put on that?
6
7 (BRIEF PAUSE)
8
9 MS. KELLY DERKSEN: I'm not sure that
10 I can be responsive to the question other than to say
11 it's a judgment call and it's based on one (1) of --
12 number 1, where a predominantly hydraulic facility
13 that has significant export revenue, it can be fairly
14 volatile, as we've seen in the past. We're adding
15 investment with respect to hydraulic infrastructure.
16 And in addition, it wasn't just the
17 fact that imbedded cost was below short run marginal
18 cost. I think, from the perspective, if we were to
19 have an outcome where all classes embedded cost was
20 below short run marginal cost, it -- from an economic
21 perspective, someone might argue that that's not
22 preferable, but from a cost allocation perspective,
23 that would be preferable.
24 The issue was the var -- the degree of
25 variability. And so I don't think you can just look

1 at some value in terms of -- of short run marginal
2 cost today and say you don't have the problem today,
3 do away wi -- with your treatment, because it's not
4 just that, it's -- it's the degree among the customer
5 classes.
6 MR. DANIEL PEACO: Let -- let me
7 unpack my question because I think maybe you responded
8 to a couple different pieces of that. I guess my
9 first question -- maybe -- maybe the -- the narrow
10 question would maybe -- maybe put to Mr. O'Sheasy
11 would be what time period he had in mind and the
12 comment that he made earlier in -- in his response to
13 -- I think it was to MIPUG.
14 MR. MICHAEL O'SHEASY: I think the
15 question that I was trying to respond to was in
16 regards to the weighted energy allocator. The
17 traditional weighted energy allocator has been based
18 upon energy cost lambdas or what you're basically --
19 well, the SAP prices which are the marginal energy
20 cost for certain time periods, and I think they're
21 averaged over eight (8) years. But you could construe
22 those to be short-run marginal costs.
23 They're -- they're supposed to be
24 shadow prices or reflections of what the short-run
25 marginal cost --

1 MR. DANIEL PEACO: I understand that.
2 My question is a little more specific. My under -- I
3 understood your response to say that it was suitable
4 to use short-run marginal costs rather than long-run
5 because of the period of time that you're designing
6 the rates for.
7 MR. MICHAEL O'SHEASY: Correct.
8 MR. DANIEL PEACO: And so my question
9 is: Can you put a number of years or months on that
10 period?
11 MR. MICHAEL O'SHEASY: Okay, I'll --
12 I'll try to. And it -- it had to do with why we were
13 adding in the capacity component. But my belief in
14 the time frame that we should look at is the time
15 frame to which these rates will apply, so -- and that
16 course varies depending on how often you have a rate
17 case.
18 But my -- my point in this is the
19 reason we do cost-of-service studies is to divide up
20 revenue requirements so we can determine revenue
21 requirement by rate or by rate class, and then
22 subsequently rates. So that's why we do cost-of-
23 service studies.
24 And so to the -- the vision of how long
25 these rates will apply to me would infer the time

period that you should look at marginal costs over. And so to try to guess a number, my guess is three (3) to four (4) years.

MR. DANIEL PEACO: Okay. Thank you. So if we're looking at a -- and I'm not sure if that goes to -- to the answer that you gave me. But in three (3) to four (4) years time, that really gets us up to the point when Keeyask and Bipole are scheduled to come into rates. Are we looking at a time frame where this cost-of-service study is to -- is to be robust over that period of time?

Or maybe more helpful is to say are we -- are we looking at a cost-of-service study that's intended to be useful and robust for some period of time after Keeyask and Bipole come into service?

(BRIEF PAUSE)

MS. KELLY DERKSEN: Ultimately, cost of service is about setting rates for -- for domestic customers. And to the extent that customers make decisions today with respect to invest -- investment in a plant or whatever it is that drives their -- their decision-making, we need to provide some stability in terms of cost allocation and rate design.

1 And so to abandon an approach because
2 you think you don't have an issue today and you think
3 you might have an issue when a new plant comes on
4 line, to me, you know, you're at the point then you
5 really need to unwind much of the assumptions that
6 underpin your cost allocation --
7 MR. DANIEL PEACO: Okay.
8 MS. KELLY DERKSEN: -- methodology in
9 totality because of the stability that you're trying
10 to bring to it in terms of the weighted energy
11 allocator, the 2CP allocator.
12 And so from that perspective, it's
13 important to provide some -- some stability. There
14 are no guarantees in --
15 MR. DANIEL PEACO: But in terms -- as
16 you sit here today and your intent, your purpose in
17 doing this, it sounds to me from -- from -- if I
18 understand your last answer, it's your hope that we
19 could set up a cost-of-service allocation in this
20 proceeding that would -- that would stand up and not
21 need -- necessarily need to be revisited for -- for --
22 until sometime after those facilities come on.
23
24 (BRIEF PAUSE)
25

1 MS. KELLY DERKSEN: Maybe you can
2 repeat your question for me just so that I have it
3 fresh in my mind, please.
4 MR. DANIEL PEACO: Okay. I'll try.
5 So I guess is it -- was it your answer that your --
6 your aspiration in this proceeding would be to -- to
7 establish cost-of-service allocation that would be
8 robust, would -- would, for all of our expectations,
9 be something that would -- that would not necessarily
10 need to be revisited until some time well after
11 Keeyask and Bipole have come into service?
12 MS. KELLY DERKSEN: That would be my
13 hope. We need to bring some closure to the -- the
14 issues. We need -- and to do that, we need to have
15 some assurance -- well, you have to have some
16 expectation that your methodology can weather some of
17 the -- weather some of the storms.
18 But again, there are no guarantees. We
19 --
20 MR. DANIEL PEACO: Well --
21 MS. KELLY DERKSEN: -- we can't do
22 that, but, yes, the expectation is we need to bring
23 some closure to the issues. We hope that it will
24 provide us some stability, some consistency in terms
25 of the methodology for a number of years. It seems to

1 me to be practically, reasonably what we want to
2 accomplish.
3 MR. DANIEL PEACO: Okay. My question
4 wasn't about guarantees. It was about aspirations.
5 And so I think we're on the same page. So when you
6 use the term "robustness" then, can we agree now we're
7 talking about -- we're trying to look at things in
8 terms of will they stand up through some of the
9 changes that are coming in the system over the next
10 several years?
11 MS. KELLY DERKSEN: I think that's
12 fair, yeah.
13 MR. DANIEL PEACO: Okay. The -- if
14 you -- and you talked with Ms. Neal a little bit about
15 the market conditions that -- that led to creating the
16 export class in the first instance.
17 But my recollection in reviewing the --
18 the NERA report that was done -- and I think it was
19 2003 or '04 -- in that one there was at least some
20 analysis done of different water conditions to see
21 whether the design was -- how much the design changed
22 whether you used average water conditions or -- or dry
23 conditions.
24 Am I recalling that correctly?
25

1 (BRIEF PAUSE)

2

3 MS. KELLY DERKSEN: I'm not sure that
4 I can respond specifically to that. I don't recall
5 that in -- in this specific report that I'm thinking
6 about, which is the classification and allocation of
7 generation transmission costs in 2004, prepared by
8 NERA. I don't recall that specific discussion, so I'm
9 not sure how far I can go with you on that.
10 MR. DANIEL PEACO: Okay. Well, I'll
11 make a representation. I don't know if we need to
12 necessarily pull it up. I think it was one (1) of the
13 -- it was clearly in one (1) of the pre -- pre-filed
14 documents, but page 41 talks about that and they've
15 included an appendix with an analysis with two (2)
16 water conditions.
17 So my question is: Have you -- have --
18 have you in this study done any similar testing of how
19 the system -- how the -- how your system is -- is
20 managed under different water conditions, either today
21 or as it would look once Keeyask is in -- in the
22 system?

23

24 (BRIEF PAUSE)

25

1 MS. KELLY DERKSEN: Specifically, no.
2 But I believe inherent in median conditions, which
3 underpin cost-of-service, considers at least, broadly
4 speaking, a variety of -- of conditions that the
5 utility can an -- anticipate occur. And -- and...
6
7 (BRIEF PAUSE)
8
9 MR. DANIEL PEACO: So ju -- to be
10 clear my -- my question was simply have -- have you
11 done an analysis of that type for this -- for this
12 study? If -- if you haven't that's fine. I just -- I
13 was -- wanted to know if you had.
14 MS. KELLY DERKSEN: Not specifically.
15 But again, what underpins cost of service is median
16 flow conditions. So, you know, to the extent that you
17 would have -- experience on an actual basis extreme
18 conditions one (1) way or the other doesn't explicitly
19 get recognized in cost-of-service other than broadly
20 speaking through median conditions.
21 MR. DANIEL PEACO: So -- so the ans --
22 so at this point you don't have an analysis of the
23 type that was done ei -- for either current conditions
24 or -- or post-Keeyask?
25

1 (BRIEF PAUSE)

2

3 MS. KELLY DERKSEN: The answer is --
4 is no. But it's a qualified no because I'm trying to
5 understand for cost-of-service purposes that look at
6 conditions on a median basis, which are roughly close
7 to -- or intended to approximate average conditions,
8 why that you would use that information to -- to drive
9 an allocation methodology if your allocation
10 methodology is not intended to explicitly in --
11 reflect those conditions.
12 So that's my struggle, is -- is what
13 would you do with that information then? And -- and
14 that's why I'm having a -- a hard time, you know,
15 other than a qualified no, responding to your
16 question.
17 MR. DANIEL PEACO: Okay. Thank you.
18 I'd like to move to get some clarification on a couple
19 of other IRs on a -- on a different topic. If we
20 could look at -- actually I think there's -- there
21 were some questions on -- let's see...

22

23 (BRIEF PAUSE)

24

25 MR. DANIEL PEACO: There was -- there

1 was a -- the PUB -- Manitoba Hydro's response to PUB-
2 I-23C...
3
4 (BRIEF PAUSE)
5
6 MR. DANIEL PEACO: And -- and I think
7 this -- this question -- I -- I just want to get some
8 clarification on this, and I think it's -- it was
9 largely answered by Mr. Cormie's earlier discussion
10 about the Bipole, but as I understand the question
11 that was -- was posed here...
12
13 (BRIEF PAUSE)
14
15 MR. DANIEL PEACO: The -- the question
16 really was -- was intended to -- to get at the
17 relationship between production at higher levels, and
18 the exports that -- export sales, and if -- if I
19 understand the response to this the explanation really
20 is that the -- any surplus energy that's produced
21 there could be purposed to a number of applications,
22 including perhaps export sales. Is that right?
23 MR. DAVID CORMIE: That -- that's
24 correct, Mr. Peaco. When we -- when we dispatch the
25 generation on the Lower Nelson and it utilizes the

1 HVDC system we don't tell the operators, oh this is
2 going to the US, or this is going to Manitoba. They
3 just push the power down to Dorsey, follow -- they --
4 they meet the power order, and the DC system doesn't
5 discriminate where it's going.
6 It arrives in southern Manitoba, and
7 then it's either used domestically on a first priority
8 basis, and -- and any surplus is exported. And so
9 there's -- the -- the system doesn't care where the
10 load is.
11 MR. DANIEL PEACO: So if -- if there
12 is additional energy available from that system, it'll
13 flow into the system. It may create an aggregate
14 condition in -- in the system that allows you to
15 increase exports. It wouldn't necessarily be one (1)
16 for one (1).
17 MR. DAVID CORMIE: Could you ask that
18 again, please?
19 MR. DANIEL PEACO: Sure. I'm just
20 saying it's -- in the event that there's additional
21 energy from the -- from the system -- from the -- from
22 the hydro sys -- Lower Nelson available to be -- to
23 move south, it may or may not one (1) for one (1) be
24 utilized for export but the system will have -- the
25 Manitoba Hydro system will have more energy, and that

may create an opportunity for additional export sales of -- of some magnitude.

MR. DAVID CORMIE: Yes. And -- and as -- as hydrology improves from low flows to high flows there is a surplus created. It will go to the highest price markets first --

MR. DANIEL PEACO: Yeah.

MR. DAVID CORMIE: -- which will tend to fill the on peak hours. As conditions improve even further you'll have off peak generation, and you'll increase your off peak generation until you are limited by your tie-line capability. And at that point, you open the spillways because you can no longer extract value.

MR. DANIEL PEACO: Sure.

MR. DAVID CORMIE: And so we will be on peak -- off peak spill as -- as conditions improve.

MR. DANIEL PEACO: The -- actually the -- the example you had in the presentation may be -- is helpful. The -- the data you have for 2014 was a -- was a relatively wet year condition. Is that --

MR. DAVID CORMIE: It was, yes.

MR. DANIEL PEACO: So can you just sort of explain just sort of in general how in that -- in that circumstance, in that year, you managed sort

1 of the -- the extra energy that you had and how that
2 related to -- to export transactions? I mean in
3 general terms, not specific transactions.
4 MR. DAVID CORMIE: Because the storage
5 capacity of our reservoirs is relatively small
6 relative to the swing that can occur in water flows,
7 we -- we were -- we were into flood mode on Lake
8 Winnipeg in maximizing discharges. And -- and as much
9 -- much water as could be released from reservoirs was
10 -- was discharged. And then all the generating
11 stations were loaded up to capacity. And -- and you
12 know we exported everything we could subject to the
13 tie-line's capability.
14 MR. DANIEL PEACO: Were you -- in --
15 in that kind of a situation are you able to structure
16 some long -- was it all sold as available energy or
17 were you able to structure some -- some firm contracts
18 for some duration given you were in that condition?
19 MR. DAVID CORMIE: In the current
20 marketplace where natural gas prices are so low and
21 customers are not buying because they fear the
22 volatility in market prices, it's hard to get a
23 forward commitment from the bilateral market, and so
24 all that energy essentially goes into the spot market.
25 MR. DANIEL PEACO: So that would be --

1 in the -- in the vernacular of the cost-of-service
2 study that would all be opportunity energy?
3 MR. DAVID CORMIE: That -- that's
4 right. Right.
5 MR. DANIEL PEACO: Right.
6 MR. DAVID CORMIE: And -- and the --
7 generally, the fear that customers have is for price
8 volatility on-peak. There's ver -- historically
9 there's always been very little fear of off-peak
10 prices.
11 And so it's rare that we will get a
12 customer who wants to hedge away their off-peak price
13 risk.
14 MR. DANIEL PEACO: Sure.
15 MR. DAVID CORMIE: And -- and all this
16 additional energy that we were selling, there was off
17 -- it was off-peak energy as a result of high flows.
18 MR. DANIEL PEACO: Okay. No, that's
19 helpful. Sort of a related question that goes one (1)
20 of the other charts. I think it's on slide 30. And I
21 think it's addressed some of the -- another -- one (1)
22 of the other questions we had on response to IR.
23 And you've talk -- you've talked about
24 this chart quite a bit today already, but I just
25 wanted to confirm a couple things here. So in looking

1 at the -- the blue area is -- is annual dependable
2 energy or domestic load, correct, on an annual --
3 annualized --
4 MR. DAVID CORMIE: Which chart are you
5 looking at, Mr. Peaco?
6 MR. DANIEL PEACO: Twenty-eight, I'm
7 sorry.
8 MR. DAVID CORMIE: The -- the blue
9 area is -- is firm load, so -- and the -- and -- and
10 the black line is just, you know, the -- the total
11 demand.
12 MR. DANIEL PEACO: Right. And firm
13 load, that would be domestic -- domestic load, or is
14 it included --
15 MR. DAVID CORMIE: That would be
16 domestic. And to the extent that we've engaged in
17 long-term firm sales and -- and the load forecast
18 changes as -- and, as a result, we are now -- we could
19 be short because of -- of the load forecast
20 uncertainty, we would then be obligated to bill to
21 serve both Manitoba load and -- and firm load
22 obligations.
23 MR. DANIEL PEACO: All right. So as -
24 - as a concept -- and obviously, this is a conceptual
25 diagram.

1 MR. DAVID CORMIE: Right.
2 MR. DANIEL PEACO: But as a concept
3 here, you're -- you're billing into the blue, both
4 firm domestic load and firm contract's already
5 executed?
6 MR. DAVID CORMIE: Right.
7 MR. DANIEL PEACO: So then, in this
8 case, if I understand the orange triangles, that would
9 be the amount of dependable energy production
10 capability you have in the system. And the orange
11 represents that you have more dependable energy
12 production in the system than you would have firm load
13 at that point?
14 MR. DAVID CORMIE: Yes. And -- and a
15 good example is what happens with Keeyask. Over a
16 period of a year and a half we bring all the units
17 online. And you've added about 3 terawatt hours of
18 dependable energy. On average, you're going to have
19 about four and a half terawatt hours of production.
20 But the Manitoba load hasn't gone up by three (3)
21 terawatt hours, it may have gone up in a year maybe --
22 maybe one (1) terawatt hour, so there's some
23 additional dependable energy off that facility.
24 And so what we -- what we've done is
25 entered into a series of dependable energy contracts.

1 There's four (3) of them, 125 megawatt sale for five
2 (5) years to Xcel Energy, a hundred megawatt sale from
3 '21 to '27 with Wisconsin Public Service, a 250
4 megawatt sale from 2020 to 2035 with Minnesota Power,
5 and -- and a hundred megawatt sales to Saskatchewan
6 from 2020 to 2040.
7 And when you plot those out, it kind of
8 looks like this wedge that you see so that over time,
9 we've -- we've, in a sense, locked up all the capacity
10 -- our -- our surplus capacity that's available from
11 adding the plant and -- and most of the dependable
12 energy, reserving enough dependable energy so that we
13 can have enough to -- to serve the Manitoba load.
14 MR. DANIEL PEACO: Okay. So in -- in
15 this -- in this idealized thing, I -- I'd understood
16 your original answer to sort of -- you were thinking
17 of this blue area as encompassing in all those
18 contracts. But are you thinking these are -- these
19 contracts are in addition to what you'd intended?
20 MR. DAVID CORMIE: Well, yeah. In
21 anticipation of having that yellow area resulting from
22 constructing Keeyask, we went at the same time and --
23 and committed to that surplus, so to those -- to those
24 contracts from the dependable surplus.
25 MR. DANIEL PEACO: So in the -- in the

1 current circumstance, the -- the orange piece of your
2 system is -- is pretty well -- is pretty well
3 contracted up?
4 MR. DAVID CORMIE: Yes.
5 MR. DANIEL PEACO: Okay. So -- so I
6 guess the question would be --
7 MR. DAVID CORMIE: Well, with -- with
8 one (1) exception, Mr. Peaco, is that -- that part of
9 the arrangement with Minnesota Power was to build a
10 new interconnection. And that added some additional
11 dependable energy capability to the system because we
12 doubled our import capability.
13 So we haven't sold back to the market
14 that energy because we've run out of new capacity. So
15 we've sold -- of -- of the 650 megawatts that Keeyask
16 is going to bring online, we've sold 650 megawatts of
17 -- of capacity sales. And so it's hard to put more
18 capacity -- or more dependable energy out of that
19 capacity, and so -- you know, until we do something
20 cute with another seasonal diversity sale that we
21 won't be able to -- we won't be able to market that.
22 MR. DANIEL PEACO: No, fair enough.
23 And the -- the yellow -- the -- the yellow portion of
24 your curve here represents all the production that you
25 would get in years that are -- that are -- have more

1 water than your driest year?
2 MR. DAVID CORMIE: That's right, and
3 that can range from zero in the -- maybe the second
4 driest year on record to the maximum, which would be
5 the highest water year on record, like 1956 or '55,
6 '56, I think --
7 MR. DANIEL PEACO: So -- so in the --
8 in the example 2014 we're talking about, there --
9 there'd be a fairly sizable chunk of the yellow as
10 part of your mix, and that's all opportunity costs
11 here.
12 MR. DAVID CORMIE: Right.
13 MR. DANIEL PEACO: So in terms of the
14 cost-of-service study, at least for -- for the test
15 year, you've got all of the -- the blue and the orange
16 is basically committed into firm contracts. And
17 that's put into the firm category of cost-of-service
18 study, and all of the yellow energy, and then
19 presumably about half of that would be sort of average
20 water year conditions, would be the energy that would
21 go into the opportunity sales category.
22 Is that right?
23 MR. DAVID CORMIE: Well, I -- I would
24 -- I would think that if the test year was the year
25 after Keeyask came in, you could say that. I'm not

1 sure that's the -- that's the condition for the
2 current test year. I'm not sure for PCOSS14 whether
3 all the dependable energy in the system had been sold
4 at that time.
5 MR. DANIEL PEACO: Fair enough. Fair
6 enough. So if you -- if you imagine this -- this
7 first step up is so the year that Keeyask comes in, so
8 you're saying then you'd -- you'd obviously see a step
9 in those -- in the contracts that come with that.
10 And you would -- and that would be a
11 change both in -- in the -- obviously the capital --
12 you know, the -- the capital investment of Keeyask
13 would come into the rates, as would the revenue
14 associated with those firm contracts. And so both of
15 those would step -- be a step function at that point?
16 MR. DAVID CORMIE: Yes.
17 MR. DANIEL PEACO: And those would go
18 for some time. And as you go through time, you're --
19 you're continually marketing any -- any of the orange
20 that's uncommitted into trying to commit that into
21 firm contracts and put that into the firm category.
22 And I guess because you're not look --
23 we haven't done a forward test year beyond the one
24 (1), we're not really looking at how that forward
25 commitment would play into the cost of service,

1 correct?

2 MS. KELLY DERKSEN: I'd just like to

3 interject, here. The -- the idea in terms of the cost

4 allocation methodology that we've represented in our

5 submission is that, notwithstanding what occurs on an

6 actual basis in terms of whether we can sell all of

7 the dependable energy and capacity above that needed

8 to serve Manitoba load in dependable conditions, it is

9 all assumed for cost-of-service purposes to be sold

10 from a -- from a firm perspective. And all of that is

11 assigned generation and transmission cost.

12 MR. DANIEL PEACO: So for the purpose

13 of that study, whether you've actually got a

14 contractual commitment or not, it -- all -- you've

15 assumed all the dependable energy that -- in that test

16 year would be sold as firm cap -- capacity and put in

17 -- and allocated to firm?

18 MS. KELLY DERKSEN: Right, and we do

19 that on a -- a five (5) year forecast. I'm sorry.

20 And -- and that's looked out by years 3 to years 8 of

21 the financial forecast and averaged. So, yes, we

22 assume all of that is sold, notwithstanding what

23 occurs on an actual basis --

24 MR. DANIEL PEACO: Okay.

25 MS. KELLY DERKSEN: -- from a firm

1 perspective.

2 MR. DANIEL PEACO: All right. Thanks.

3 That's helpful. I think there was a -- just some

4 confusion about how those -- and I thought this

5 diagram was a helpful way to kind of sort out those

6 different pieces.

7 MR. DAVID CORMIE: Yeah, and -- and

8 today, we may not have sold it, but there's a good

9 chance that over that four (4) or five (5) year

10 period, we -- it will be sold. And I think Ms.

11 Derksen is just saying that, you know, we're -- we're

12 going to assume that you sell it, and I'll keep trying

13 to sell it, and -- and hopefully, we --

14 MR. DANIEL PEACO: In terms of what's

15 built into the cost-of-service study, that's the

16 assumption?

17 MR. DAVID CORMIE: Yeah.

18 MR. DANIEL PEACO: Okay. Fair enough.

19 I guess the last question I had has to do with -- it

20 really goes to a question about the classification of

21 the -- the hydro system, the Lower Nelson, whatever,

22 in terms of its all -- its allocation to export versus

23 -- and -- and its corollary to the -- the question I

24 had earlier about the -- when you have surplus energy,

25 how does that -- how does that go to serve domestic

1 load versus export.

2 But in terms of the design of the --

3 take any of the facilities in the Lower Nelson or --

4 or the Keeyask plant, you have a certain number of

5 turbines. And in -- in a year when you have low water

6 defining the dependable energy, those -- the -- the

7 utilization of the turbines, all of the -- all the

8 turbines in those, all go to provide the -- the

9 capacity component of your requirement.

10 So all of those turbines are necessary

11 to make -- make the capacity requirements that you've

12 -- you've established, correct?

13 MR. DAVID CORMIE: Yes, and I -- I

14 explained this morning how in a normal year, the

15 capacity reserve requirements that the system has

16 would normally be held by our thermal resources and

17 our imports. What will happen in a low water year,

18 the capacity reserves will be carried by shutdown

19 units in the north. And you'll -- your base load,

20 your -- you'll base load your thermal resources.

21 You'll base load your imports.

22 And you'll have some shut down capacity

23 on the Nelson River that can utilize short-term

24 reservoir storage if you were to lose the coal plant

25 at Brandon or a combustion turbine. And so the --

1 they -- that capacity sits there in reserve as long as
2 it's not a DC contingency.
3 MR. DANIEL PEACO: So -- so in that --
4 in that dry condition, then, you're using some of
5 those turbines, sort of holding in reserve -- managing
6 the water to -- to be able to run them full out for --
7 for a period of time as necessary?
8 MR. DAVID CORMIE: That's right. And
9 in our -- and our strategy during droughts is to hold
10 the reservoirs at those stations full, so that you
11 have the full quarter-million megawatt hours in short-
12 term storage available to deal with those kind of
13 contingencies that -- that could happen either to your
14 import capability, or to your combustion turbine, or
15 your thermal capability.
16 Or if there -- if there was congestion
17 on the import line and you weren't able to import, you
18 would manage that risk through those short-term energy
19 reserves that are available. They're -- and they're -
20 - par -- there's about a quarter of a million megawatt
21 hours that can be called on under the capacity that's
22 shut down during -- in low flow years.
23 MR. DANIEL PEACO: Okay. And the --
24 and the turbines there, are they -- are they basically
25 interchangeable? Are there certain turbines that are

1 designed to operate during low flows and others that
2 are...
3 MR. DAVID CORMIE: No, there are
4 potentially thirty-two (32) units right there that are
5 a hundred to a hundred and --
6 MR. DANIEL PEACO: And as -- and as
7 your water condition goes up from medium to -- to 2014
8 conditions, you just get more utilization across the
9 turbine?
10 MR. DAVID CORMIE: That's right.
11 Yeah.
12 MR. DANIEL PEACO: Yeah. Okay. Thank
13 you.
14 MR. JOHN ATHAS: I'm -- I'm third --
15 batting third for the team? Is that -- can you guys
16 hear that one? Okay. And my name's John Athas. The
17 -- a couple of things to just spe -- I wanted -- I
18 wanted to start off a little bit with slide 23 in your
19 presentation.
20 And I actually have -- I -- I'd like to
21 get an answer for -- on a couple of, you know,
22 definitely somewhat hypotheticals or somewhat way --
23 how we apply judgment calls. You know, clearly, the -
24 - the generation provides the two (2) services. It
25 meets demand and provides enough energy, as you guys -

1 - you guys have said. And I -- if I -- from all the
2 things that you've put forward, the dominant planning
3 parameter is energy, the dependable energy needs based
4 on all the things we've talked about.
5 Is that correct?
6 MR. DAVID CORMIE: Yes, if you look at
7 our expansion plans, you'll see the -- the driver for
8 energy and capacity are very close to each other.
9 MR. JOHN ATHAS: Well, that's what I
10 wanted to just get at. I mean, how -- how -- what --
11 what's the lag for when you need capacity compared to
12 when you need dependable energy? You know, say -- you
13 know, not counting -- before you account for Keeyask
14 going in? You know, if -- if you're looking at the
15 pre-Keeyask decision. I'm just trying to get an idea
16 as to how close that -- that number is.
17
18 (BRIEF PAUSE)
19
20 MR. TERRY MILES: I'm trying to
21 remember.
22 MR. JOHN ATHAS: You -- you can give -
23 - give me a range. I mean, I'm not -- this is not too
24 -- this is not a three (3) decimals places kind of
25 discussion.

1 MR. TERRY MILES: You know what, I'm -
2 - I'm going to -- it's a couple of years, two (2) or
3 three (3) years, I think, in that time frame. I'm
4 trying to think what -- just looked at that. I -- I'd
5 have to confirm it, but --
6 MR. JOHN ATHAS: Okay. So --
7 MR. TERRY MILES: -- it -- it --
8 MR. JOHN ATHAS: -- so -- so using --
9 using the couple of years, and just -- you know, and I
10 -- and I -- there's no -- there's no series of
11 positioning questions here to get -- to get you into a
12 corner, or anything. I'm just trying -- so -- so from
13 the standpoint of allocating on energy for all the --
14 all the generation costs, a couple of years difference
15 is enough for you to not consider allocating any
16 generation on demand. Is -- is that -- that the prime
17 reason not to allocate any generation on demand?
18 MS. KELLY DERKSEN: We do allocate
19 generation on demand. It's not explicit, but we do
20 allocate generation on demand. It's implicit between
21 the on and off, and the other period prices inherent
22 in the energy market with the caveats that we've been
23 talking about today, which is upon the advice of
24 Christensen that that demand inherent in that energy
25 price may not be adequately reflected in comparison to

1 past because of the changes in -- in the energy
2 market.
3 So we -- this notion that we classify
4 generation 100 percent energy has to be significantly
5 caveated. And at least in the view of Manitoba Hydro,
6 in -- in our view, because we do consider demand, you
7 don't see it explicitly. And the -- the question now
8 is, have you accounted enough for capacity in the
9 methodology that you have chosen because of the
10 changing circumstances in the energy market that you
11 are participating, and that's --that's the question --
12 MR. JOHN ATHAS: Yeah, I -- I
13 understand.
14 MS. KELLY DERKSEN: -- and -- and
15 that's what gave rise to the capacity adder.
16 MR. JOHN ATHAS: Now, have -- have you
17 filed -- filed the equivalent -- because I know we
18 have the model that we could do it, too, but I just
19 want to make sure it's not already part of the record.
20 You filed the equivalent to -- and I
21 guess I'm going to put words in your mouth, so please
22 correct them, is that if -- if a hundred percent
23 energy allocator is not weight -- not giving a
24 weighted average or a seasonality, have you -- have
25 you made that run?

1 (BRIEF PAUSE)

2

3 MS. KELLY DERKSEN: You have to -- you

4 have to help me out. I -- I'm not sure that I

5 understand your question.

6 MR. JOHN ATHAS: What would you --

7 what would you consider -- how would you model the

8 desire to have it be purely a hundred percent energy

9 and not have any implicit basis for demand?

10 MS. KELLY DERKSEN: You would do it on

11 an unweighted base -- on an unweighted energy basis.

12 MR. JOHN ATHAS: Like, do you have a

13 run that you've done like that?

14 MS. KELLY DERKSEN: We don't. I think

15 -- let me just check our materials, though.

16

17 (BRIEF PAUSE)

18

19 MS. KELLY DERKSEN: We -- we have not

20 run -- run that.

21 MR. JOHN ATHAS: Not a problem. It's

22 not a -- and it's not -- not requested as an

23 undertaking, so -- right now, so. So if -- if --

24 MS. KELLY DERKSEN: Directionally,

25 though, if you went down that path -- let's just talk

1 about outcomes. If you went down that path, you would
2 likely load...
3
4 (BRIEF PAUSE)
5
6 MS. KELLY DERKSEN: My expectation is,
7 if you were to go down that path you would load
8 additional cost responsibility onto the -- the high
9 load factor customers, presumably the customers in the
10 -- the large volume industrial type customer classes.
11 MR. JOHN ATHAS: And would you ha --
12 care to speculate as to what that percent of those
13 cost changes from -- you know, that you've -- that --
14 from going a hundred percent, the way you describe it,
15 for the energy allocator to what you've got now for
16 implicitly capt -- capturing the effect of the demand?
17 I mean, is that -- I know it's not a
18 50/50 way to demand energy because it -- it would be a
19 lot more explicit if it was -- if it was, sorry,
20 rather implicit. So I just was wondering how much you
21 think that you've moved toward demand because of the -
22 - the weighted methodology.
23 MS. KELLY DERKSEN: In the past, we
24 have put information on the record, order of magnitude
25 of somewhere 80 percent energy, 20 percent capacity

1 implicit in -- in the weighted energy allocator. I
2 have no reason to believe that it would be materially
3 different today tha -- than that.
4 MR. JOHN ATHAS: That -- that was very
5 helpful. So -- so if the -- if the need for capacity
6 to meet demand as well as new generation to provide
7 dependable energy were right -- right smack in
8 lockstep so that you needed them in the same year for
9 all -- all -- essentially, all intents and purposes,
10 over a time period, would it -- would it make you more
11 likely to start looking at an explicit demand
12 allocator?
13 MS. KELLY DERKSEN: I'd have to give
14 that a little bit more thought, but my initial
15 reaction is -- is, no. And -- and the reason is, you
16 know, we have a dominantly hydraulic facility,
17 notwithstanding, you know, the fact that we may need
18 to serve capacity needs slightly earlier or lesser
19 than -- than energy need.
20 It's -- it's the overarching sort of
21 philosophical debate about why you would invest in
22 significant fixed costs like you would if you were to
23 put in hydraulic infrastructure. And you do that
24 because, over the long-run, it's cheaper. It's more
25 economic to serve your load over that long-term

because you're attempting to avoid --

MR. JOHN ATHAS: Sure.

MS. KELLY DERKSEN: -- fuel costs or -- or costs that are -- can be highly variable. And so --

MR. JOHN ATHAS: And I'm not -- I'm not questioning that, just to make sure... I mean -- and I wasn't even trying to get to a certain percentage or target. I just was merely saying, from a methological (sic) standpoint, would you -- if you thought that -- that the -- that, you know, one (1) person's perspective on the panel says, I'm buying -- I'm putting in Keeyask for energy, and if the other one said, I'm putting it in for capacity, would you start analyzing or considering demand as an allocator for -- explicit demand for some allocator for the generation costs?

MS. KELLY DERKSEN: No. I -- I think you look at it from a conceptual perspective why you again invest in that kind of -- of infrastructure. And you put that infrastructure in place knowing full well that you are going to incur very significant upfront fixed costs. But you do that because, over the long-term, there's a benefit. And there's a benefit because you can essentially secure your energy

price.

And so to me, conceptually, notwithstanding how we have to --

MR. JOHN ATHAS: Okay.

MS. KELLY DERKSEN: -- to serve our load in the short-term, that conceptually it makes sense at least to give a heavy recognition of energy.

MR. JOHN ATHAS: Okay, one (1) last one on this. And just will -- wouldn't it -- wouldn't that make you -- wouldn't that make you want to use a pure all -- energy allocator then rather than the weighted average, the same logic?

(BRIEF PAUSE)

MS. KELLY DERKSEN: I think there's probably a rational argument to be made to go in that direction. The -- the struggle then is you know that that capa -- or that infrastructure has to serve customers' energy requirements as demanded by them, and to not reflect ener -- any demand component in it may be fairly, at a minimum, an aggressive perspective.

MR. JOHN ATHAS: Okay. So is the -- is the weighted average methodology more designed to

capture the effect of the -- the different opportunity costs for the -- for the energy at those -- at those points in time by -- you know, by weighing them on price?

MS. KELLY DERKSEN: I think that would be a -- a fair -- a fair description, yeah.

MR. JOHN ATHAS: Okay. Now, I have -- the -- the second kind of question -- or questions is, again, this is a -- I'd actually like Christensen to see if they can provide some information here. And I -- and I feel like I'm having -- this is going to confession when you can't see the person on the other side here, so I apologize for that.

But -- but the -- the -- in -- in your experience, in utilities that have a -- an interruptible service class of customers, do -- and they -- and they go through a cost-of-service allocation process, do they allocate any generation capacity-related costs to that class?

MR. MICHAEL O'SHEASY: I'd think the answer is yes, but I want to make sure I understand the question. Let's imagine that you've got a rate class that is totally interruptible. And so when you do a cost-of-service study on a rate class like that, you will give them capacity cost. It's just you will

1 basically give them a credit for their avoided
2 reliability cost.
3 So let's pretend for the sake of
4 discussion that generation capacity cost is twenty
5 dollars ($20) a kW. Well, you might give them a
6 credit because of their interruptibility that will
7 save you CT costs. You might give them a credit of
8 six dollars ($6) a kW.
9 MR. JOHN ATHAS: Okay. I follow that.
10 You're giving them -- that's working on a detrimental
11 basis. Are you -- are you familiar with any utilities
12 that -- that do it on a -- you know, kind of a
13 bottoms-up approach, and whether they allocate any
14 genera -- you know, where they may go through and --
15 and not allocate any capacity costs to the -- to a
16 rate class that's interruptible?
17 MR. MICHAEL O'SHEASY: No, I'm not.
18 No, I'm not familiar with that.
19 MR. JOHN ATHAS: Oh.
20 MR. ROBERT CAMFIELD: No, Michael. To
21 echo that, I -- I cannot think of any utilities that
22 pursue interruptible rates that way.
23 MR. JOHN ATHAS: Okay. Well, it's --
24 it strikes me -- and it's been a while, but I think
25 that the -- at a time when a utility in Connecticut

1 had a separate production and transmission demand
2 charge, that they -- that that was fully waived in --
3 for interruptibility. And it was an embedded, cost-
4 based number, but I -- you know, I just wanted to see
5 how widely spread that might be, and I guess it's not.
6 MR. ROBERT CAMFIELD: The difficulty
7 with that approach, by the way, that is to say
8 interruptible service rate class that gets no fixed
9 charges for the generation facilities that provide the
10 energy, and that is to say that simply those total
11 fixed costs are to provide both capacity but also
12 associated with the provision of fuel cost savings.
13 Coal-fired units and of course right
14 here in front of us, the hydraulic facilities of
15 Manitoba Hydro are better than any other technology in
16 terms of avoiding fuel costs. So because those
17 interruptible service customers use energy, it's
18 appropriate to charge the fixed charges associated
19 with the provision of the energy.
20 MR. JOHN ATHAS: Okay. Now, is -- is
21 there -- is there --
22 MS. KELLY DERKSEN: And -- and, you
23 know, I can add, on the -- on the gas side of our
24 business, we have that kind of structure for cost
25 allocation purposes. We have an interruptible class,

1 and in the absence of an explicit methodology choice,
2 we would have not allocated any fixed pipeline costs
3 to -- to those customers.
4 And in favour of a methodology that
5 considered the fact that they -- they used that system
6 in all periods other than those periods in which
7 they're being curtailed, that they should make some
8 contribution to fixed costs. So it's sort of a -- an
9 analogy I can draw from our gas business.
10 MR. MICHAEL O'SHEASY: Also, I'd to
11 add one (1) clarification. When I said a utility
12 might provide a six dollar ($6) per kW credit, for
13 example, for a voided peaker cost, usually if it's a
14 curtailable cus -- customer, he's not cur --
15 curtailable twenty-four (24) hour -- 7/24, three
16 hundred sixty-five (365) days a year.
17 Usually the tariff has certain
18 provisions to it that says you can only curtail me for
19 certain time periods, or you must warn me ahead of
20 time. That's unlike the value of a actual combustion
21 turbine, which you can crank up at any moment. So
22 normally a utility would take the value of a
23 combustion turbine and de-rate it for the actual
24 requirements of that interruptible tariff.
25 MR. JOHN ATHAS: Okay. So -- so then

1 -- then let me see if I can summarize it this way.
2 You know, is that -- so with one (1) option being, as
3 I was kind of posing, that -- that they -- you -- you
4 allocate no -- no fixed capacity cost to the -- to
5 that rate class. Another -- the next option could be
6 that you've mentioned, give some sort -- do some sort
7 of decremental where you decrement the amount of
8 capacity cost based on a market value of capacity.
9 And then further you could -- you could discount that
10 because it's not as universally available as a -- as a
11 combustion turbine.
12 Is that fair to kind of summarize just
13 how we went through things?
14 MR. MICHAEL O'SHEASY: That's fair.
15 MR. JOHN ATHAS: Okay. Now, then you
16 also mentioned the fourth thing which I guess is --
17 maybe is if those are the columns and this is the row,
18 that you -- that some of the -- some amount of money
19 should be allocated to them because they are -- are
20 utilizing the generation to get energy.
21 MR. MICHAEL O'SHEASY: That's correct.
22 MR. JOHN ATHAS: Okay. Now, I guess
23 the ques -- the -- the parallel here, and I don't --
24 and this is not because I -- I'm trying to lead
25 anybody to a preference of mine or not, so just -- is

1 I -- I think that -- it struck me that the parallel to
2 that is the opportunity sales. You don't have to make
3 them. You make them when it's to your adv --
4 advantage when you have enough water. You have no
5 obligation to serve the -- to serve a customer because
6 it's even short -- it sounds like unless you do a -- a
7 short-term firming of that contract there's no need
8 for deliverability. And I guess that -- that allocate
9 -- doing it on a decremental basis or allocating them
10 on a -- on a discounted basis meth -- those things
11 that you just -- just discussed, seemed to be
12 different than what you proposed for the opportunity
13 costs.
14 MR. MICHAEL O'SHEASY: So what I was
15 talking about with the pricing is -- is -- has nothing
16 to do with the allocation of costs. We were just
17 talking about how you set the rate for the customer.
18 MR. JOHN ATHAS: Well, I was talking
19 about the -- the cost allocation to the class, because
20 I thought I started with that from the very beginning.
21 So hopefully that doesn't change the answer much
22 because then we get -- if not -- if it does we can re
23 -- we can re-run through all those options --
24 MR. MICHAEL O'SHEASY: I -- yeah --
25 MR. JOHN ATHAS: -- with -- with you -

1 - with us being on the same page of the cost-of-
2 service as opposed to rate design.
3 MR. MICHAEL O'SHEASY: If -- if you're
4 talking about how do you allocate the cost to an
5 interruptible customer, that's a little more
6 complicated. And normally what utilities try to do in
7 that case is they will take the customer as if he were
8 not interruptible and in -- and allocate full cost to
9 him. And then the revenue that will show up in that
10 column will be a fully costed rate, without any credit
11 whatsoever.
12 So that resemblance of we'll call a
13 'virtual revenue' will match the vir -- the allocated
14 cost that came to it. And then the credit that is
15 actually provided to that customer will be allocated
16 to everybody who benefit by that resource of his
17 curtailability.
18 MR. JOHN ATHAS: Okay. So I -- I
19 follow that. And that's -- and that's exactly what I
20 thought we were talking about from when we went
21 through on the cost-of-service in which you -- thought
22 about the rates area. So the -- so there is a fixed
23 cost recovery related to capacity that happens under
24 that -- from the interruptible customers --
25 interruptible service rate class then?

1 MR. MICHAEL O'SHEASY: Correct. We're
2 giving him a credit for the value he brings to the --
3 the system for his curtailability.
4 MR. JOHN ATHAS: Now, I'm -- I'm --
5 yeah, I'm just talking about the net. It's -- it's
6 unlikely that -- that the credit we gave is more than
7 the -- the embedded costs that were allocated to that
8 class?
9 MR. MICHAEL O'SHEASY: Correct.
10 MR. JOHN ATHAS: Okay. So -- so some
11 of that remains. Some of the class that -- the cost
12 that we allocated on generation remains assigned to
13 that customer class, and has to be collected in one
14 (1) -- one (1) or -- or several different rate
15 components to be named later.
16 But the -- so now -- now my question
17 goes to, I think of that as a parallel to the
18 opportunity sales, and -- because that's -- and -- and
19 I really have -- and -- and I'm not -- not -- I'm
20 saying that based on what you've just said, doesn't
21 that sound to conflict with not allocating any
22 generating costs to -- to -- based on opportunity
23 sales?
24 MS. KELLY DERKSEN: I -- I haven't
25 interpreted where you're going, you know, the question

as have we -- you know, in view of the fact that you -- you're considering opportunity sales really not a whole lot different than curtailable kinds of customers, is it reasonable to allocate some fixed cost to -- against opportunity sales?

And I suppose you find all kinds of arguments to allocate cost against exports, and the challenges -- number one (1), like I like to say, you have to do the smell test at the end of it. And -- and the smell test is if you bill to serve Manitoba load and you generate an outcome where on a unit cost basis it's costing you more to serve the export sales in -- in total, then your domestic customers -- either you've got to flag cost allocation methodology or you've got to completely reevaluate the business model that you are pursuing because it shouldn't cost more to serve those sales that are temporary on -- on some basis than it does to serve your domestic customer needs three hundred and sixty-five (365) days a year, eight hundred and six (806) --

MR. JOHN ATHAS: So -- so --

MS. KELLY DERKSEN: -- eight thousand seven hundred and sixty (8,760) hours a year also. So you -- you have to start -- you -- you know, you can do that and you can rationalize it the way that you

1 have done, but you always have to step back and say
2 what -- what have you done, and does it make sense.
3 And you might even conclude that it
4 makes sense but the only customer classes that that
5 impacts at the end of the day is domestic customer
6 class responsibility, and that's what you have to be
7 mindful of.
8 MR. JOHN ATHAS: Oh, I recognize that.
9 I mean, this is -- this is all about slicing up the
10 pie. And so -- so the -- so I guess one (1) last
11 thing on that is suppose -- and this was for
12 Christensen. It -- suppose I'm sitting here as a
13 utility that's completely balanced. My peak demand,
14 my capacity requirements were based on an ISO that I'm
15 part of, everything in balance, and I find out that --
16 that somebody wants to plop an air reduction plant
17 that's about 30 megawatts on my system.
18 And they want to be fully
19 interruptible. They don't -- they don't care how many
20 -- how many hours I get interrupted because they
21 dispatch their -- their air reduction production to
22 all different plants, and just truck it from different
23 places.
24 Would I -- and -- and they're trying to
25 negotiate a price, if they don't want to pay a price

1 that -- that's higher because it includes some
2 embedded capacity cost -- now the capacity is there.
3 I'm not -- I'm not adding new capacity for them. And
4 -- and if they don't want to -- would -- would then
5 you insist on allocating costs to the -- to that -- to
6 that new customer class of one (1)?
7 MR. MICHAEL O'SHEASY: I -- I think
8 the question is -- you've added a new customer who's
9 totally interruptible, and the question is are you
10 going -- are you willing to sell him power at strictly
11 variable cost or are you feeling like in your cost-of-
12 service study you ought to allocate him fixed costs
13 too?
14 If that's the question, then all the
15 utilities that I deal with feel like we do average
16 rate making and everybody requires a share of those
17 fixed costs. And, yes, indeed we would allocate costs
18 to that air products or air separation plant. They
19 would get credit for their interruptibility, but there
20 would be the cost of generation beyond that that they
21 would be allocated.
22 Since no additional generation had to
23 be added, that would lower the fixed cost allocation
24 to everybody's benefit. But utilities, in my
25 experience, say that's the fair and right way to do

1 business, just like as if a thousand residential
2 customers were to add some type of additional
3 appliance to their system incur -- that was
4 interruptible, maybe a pool pump on their swimming
5 pool or something that was totally interruptible but
6 yet it increased the loads to the system, yes, indeed
7 their rates would have to cover a certain portion of
8 generation costs.
9 MR. JOHN ATHAS: I understand. I -- I
10 appreciate that. I mean, I'm just taking an
11 opportunity to discuss it with --
12 MR. MICHAEL O'SHEASY: Okay.
13 MR. JOHN ATHAS: -- with a couple in-
14 house and -- and external experts because I really
15 couldn't get anybody at the hotel bar interested in
16 this discussion last night at all; I don't know why.
17 They were more interested in one (1) of the hockey
18 games on.
19 Okay, so the -- so turning to -- back
20 to PUB-70 that we had up earlier. There's just a
21 couple of quick questions. And they're definitely not
22 conceptual and other stuff. It's just these are --
23 these are data questions, so hopefully we'll zip
24 through the -- the next two (2) pretty quickly.
25 So if we put up that PUB-70. We had a

1 table that showed when you add Bipole III. And I
2 guess it showed the -- the total cost of different
3 assets for '20/'21. If we could just go down to -- to
4 that spot, where we -- the second table, I believe.
5 The first one I think was before them and the second
6 one had the... And actually, I'm sorry, is -- is the
7 -- I think it's the -- it definitely was one in
8 dollars not percentage, page 7.
9 Okay, on this table the first question
10 I have is: Can you -- do you know what the -- what
11 the investment costs were that are assumed for these
12 numbers for Keeyask, Bipole III, and -- and the inter-
13 tie? Because if we scroll down I think there's the
14 generation. There's the transmission inter-tie. Do
15 you know what the capacity -- I mean the capital cost
16 of those three (3) assets was to come up with these?
17 MS. KELLY DERKSEN: I'm sorry, you're
18 looking for Bipole III, the US -- the new US inter-tie
19 --
20 MR. JOHN ATHAS: And Keeyask.
21 MS. KELLY DERKSEN: -- as well as --
22 MR. JOHN ATHAS: Keeyask.
23 MS. KELLY DERKSEN: -- as Keeyask?
24 MR. JOHN ATHAS: And Keeyask, yeah.
25 MS. KELLY DERKSEN: In total or

1 separate?

2 MR. JOHN ATHAS: Separately.

3 MS. KELLY DERKSEN: Well, we know that

4 -- are you looking for total or are you looking broken

5 down?

6 MR. JOHN ATHAS: Well, I mean, just

7 the -- there's a capital cost associated that gets you

8 the $90 million of -- of depreciation for Keeyask.

9 You know, what's -- what's that number that's

10 associated with that? And -- and there's -- you know,

11 some of the -- some of the lines that says BP III has,

12 you know, got a capital cost to it, too, for BP III.

13 MS. KELLY DERKSEN: Right. Bipole III

14 invest cost is expected to be approximately $4.5 --

15 MR. JOHN ATHAS: Okay.

16 MS. KELLY DERKSEN: -- million.

17 Keeyask is approximately 6.5. And the US inter --

18 inter-tie is...

19

20 (BRIEF PAUSE)

21

22 MR. DAVID CORMIE: The US inter-tie

23 costs are about 350 million in Canada. And then

24 there's a contribution Manitoba Hydro's making through

25 its subsidiary to the -- the US portion. We're paying

1 80 percent and Minnesota Power is paying 20 percent of
2 that cost. And I don't know what the total of that
3 is. I think it's 491. 491 million is the total US
4 cost of which we're picking up the --
5 MR. JOHN ATHAS: If -- if --
6 MS. KELLY DERKSEN: I think though we
7 -- for this preparation of this IR we've assumed both
8 of those costs in the preparation of these materials.
9 MR. JOHN ATHAS: And they total...?
10 MS. KELLY DERKSEN: Subject to check,
11 I thought it was order of magnitude about 900 million.
12 MR. JOHN ATHAS: Okay. If we could --
13 if you find that it's materially different than that,
14 it'd be great to update it in the next couple of days.
15 Okay. The -- the next -- the next
16 question is on PUB-10B. And -- oh, I'm sorry. That's
17 right. I forgot one (1) question around that.
18 There's -- there's a northern station related to -- on
19 the transmission side related to the -- the -- getting
20 Keeyask and Bipole into place -- Bipole III in place,
21 Keewa -- Keewatinohk.
22 And is that in there, any of these
23 numbers anywhere?
24
25 (BRIEF PAUSE)

1 MS. KELLY DERKSEN: The $4.5 billion
2 number with respect to Bipole III would include Riel,
3 as well as Keewatinohk.
4 MR. JOHN ATHAS: Okay. Great. Now
5 jumping to -- to PUB-10B, the -- the -- in the
6 response, we -- we kind of -- we meant that the
7 question was in the context of, you know, a cost-of-
8 service study, not necessarily a financial report.
9 But I just wanted to -- I want to make
10 sure that we understand what you mean by -- by
11 "costing purposes" when you -- in -- in the -- in the
12 response. I think it's...
13 MR. MICHAEL O'SHEASY: Can you point
14 me to which question and sub-question you're referring
15 to?
16 MR. JOHN ATHAS: I believe it -- I
17 thought it was 10B. And if that's ten (10) up there
18 and that's 'B', and that's the...
19 MR. MICHAEL O'SHEASY: Costing
20 purposes.
21 MR. JOHN ATHAS: Cost -- the costing
22 practice it says there.
23 MR. MICHAEL O'SHEASY: Okay.
24 MR. JOHN ATHAS: I must have not been
25 able to read my own handwriting.

1 MR. MICHAEL O'SHEASY: Yeah, yeah.
2 Okay. I think the costing practice that you're --
3 we're referring to right here is typically a utility
4 in the lower forty-eight (48) will sell electricity
5 under a dependable contract or an as-available
6 contract, much -- very much similar to what Mr. Cormie
7 was talking about with dependable sales versus
8 opportunity sales.
9 Now, oftentimes the utilities that we
10 work with, what they refer to -- what they call -- as
11 you call opportunity sales, they call them economy
12 energy sales. And so the common costing practice in
13 those jurisdictions that we're referring to, they'll
14 allocate fixed costs on those dependable sales.
15 And then the opportunity sales, which
16 they'll call economy energy sales, oftentimes what
17 they'll do is, rather than necessarily allocating
18 variable costs to them, they'll just take those
19 economy energy sales revenues and allocate them back
20 to their domestic customers.
21 And then their domestic customers will
22 be allocated all variable costs, so it'll wash, so to
23 speak. And if there is any profits based on those
24 economy energy sales, they'll accrue to the benefit of
25 the domestic customers.

1 But you get the same result as if you
2 had taken the economy energy sales, left them in the
3 export column. They then would flow down to your NER
4 and they'll be allocated back. So that's what we mean
5 by 'common costing practice'.
6 MR. JOHN ATHAS: That -- that sounds
7 great. Now, you mentioned other jurisdictions. Some
8 do it -- or some distinction between the -- the firm -
9 - oh, I forget which word you used. It was --
10 MR. MICHAEL O'SHEASY: Dependable.
11 MR. JOHN ATHAS: Dependable, that --
12 and versus that opportunity. Do you -- and you -- it
13 sounded like you said that they -- they handle those
14 different. And -- one (1) they may -- just -- can you
15 just give me an idea of how -- what that -- how they
16 handle them differently?
17 MR. MICHAEL O'SHEASY: Well, to me,
18 the big difference in the way they handle them in
19 terms of a difference is focus on the dependable
20 sales. Oftentimes, utilities in the lower forty-eight
21 (48) will take their wholesale, dependable sales,
22 which are oftentimes -- they're -- usually those
23 prices are regulated by the FERC, or unless it's an
24 open market type of contract. But they will allocate
25 firm costs to those dependable sales. And then any

1 contributions -- any margin that's left over, which
2 Manitoba Hydro refers to as NER, the Utility will keep
3 that in that column. They won't take the margin and
4 allocate it back to domestic customers. It's like two
5 (2) profit centres, if you will: domestic and
6 wholesale, as far as the dependable sales are
7 concerned.
8 Now, it -- to the extent dependable
9 sales are lucrative for the Company, the -- if it's an
10 IOU, that will help domestic customers, too, because
11 it will lower the cost of equity. But normally the
12 utilities that we work with don't allocate back the
13 margin they make off dependable sales to dom --
14 domestic customers. That's -- that's a difference in
15 the two (2).
16 MR. JOHN ATHAS: Okay.
17 MR. ROBERT CAMFIELD: That's often
18 referred to as partial and full requirements wholesale
19 services.
20 MR. JOHN ATHAS: Yeah. Okay.
21 MR. ROBERT CAMFIELD: Where -- where a
22 certain share of total costs are allocated to them,
23 and they are profit centres, as Michael is suggesting.
24 MR. JOHN ATHAS: Great. Thanks.
25 There's one (1) -- one (1) last point to kind of talk

1 about. Can we put slide 39 up? And -- and I think
2 there's a lot of great information on this slide, but
3 I just want to make sure I understand what it -- what
4 it is. In the blue versus the green, the first two
5 (2) in the legend, that's -- that's taking the -- that
6 energy revenue allocation as -- as you had the
7 discussion, Ms. Derken (sic), earlier about the
8 different -- with one (1) of the Intervenors about the
9 different ways it's -- how it's allocated with, you
10 know, netting out some direct costs and -- and a total
11 allocated cost basis. And it's certainly not GNT.
12 So now you're changing -- and to get
13 that numbers in green, you change that number to G --
14 that methodology to just GNT?
15 MS. KELLY DERKSEN: Yes, that's true.
16 I just wanted to -- to clarify for the record that if
17 you choose to go down the path of allocating net
18 export revenue on the basis of GNT, which is the gre -
19 - the green -- the green columns on the slide, then
20 you really very seriously ought to consider abandoning
21 the export class entirely.
22 Because essentially, what you're doing
23 is allocating export revenue on the basis of GNT first
24 through GNT cost assignment to an export class, and
25 then the return on the basis of GNT. So I just wanted

1 to point that out.
2 MR. JOHN ATHAS: Well, that -- no,
3 that's -- that's great, because you just saved
4 everybody about fifteen (15) minutes of me -- of -- of
5 rambling questions, because that's exactly where I was
6 going. So it's effectively getting rid of the -- the
7 export class? The same ar -- math as getting rid of
8 the export class?
9 MS. KELLY DERKSEN: There's a couple
10 of nuances. If --
11 MR. JOHN ATHAS: Yeah, I know. You've
12 got the ones that are charged directly and to take it
13 out of the export class first before it gets --
14 MS. KELLY DERKSEN: Right. You -- you
15 --
16 MR. JOHN ATHAS: The -- the major
17 ones, anyway.
18 MS. KELLY DERKSEN: -- there would be,
19 you know, some debate on -- on what you do with those,
20 but that's a -- in a sen -- effectively what you've
21 done.
22 MR. JOHN ATHAS: Okay. And can -- can
23 we get the -- this one is a -- is an undertaking, but
24 can we get a table with the data points for this?
25 MS. KELLY DERKSEN: Which ones in

1 particular, please?

2 MR. JOHN ATHAS: All of them. You

3 have -- you have five (5) cases, five (5) -- whatever,

4 eight (8) classes there. I mean, we want a -- we'd

5 like a table of, you know, forty (40) numbers.

6 MS. KELLY DERKSEN: Oh, you're looking

7 for the specific RCCs, is what you're looking for

8 here?

9 MR. JOHN ATHAS: And the -- the number

10 -- the -- the RCCs and the -- or the percentages that

11 go along with each of these.

12 MS. KELLY DERKSEN: Sure. That can be

13 done.

14

15 --- UNDERTAKING NO. 7 Manitoba Hydro to provide

16 RCCs and the percentages

17 that go along with each of

18 them

19

20 MR. JOHN ATHAS: Okay. Now, does --

21 then just to make sure that I understand that when you

22 change the methodology, you're not changing revenue

23 that you're collecting from any of these classes.

24 You're just changing the -- the revenue responsibility

25 you've given them.

1 Is that correct?

2

3 (BRIEF PAUSE)

4

5 MS. KELLY DERKSEN: I suppose it

6 depends on how you -- how you look at what export

7 revenue is. If it's revenue --

8 MR. JOHN ATHAS: I'm -- I'm just

9 talking about the -- these --

10 MS. KELLY DERKSEN: -- for each

11 customer class --

12 MR. JOHN ATHAS: -- and these dome --

13 these domestic classes, not to -- not to interrupt. I

14 apologize. But just for these domestic classes, the

15 net revenue that they -- that you're going to try to

16 collect from them that are represented in -- in these

17 points. That -- the -- the rate of return that you're

18 calculating you get because you -- they all have the -

19 - do they all have the same revenue and you're just

20 changing the revenue responsibility, so obviously that

21 changes the -- the return for each class?

22 Is that the way that these were

23 produced? I mean, there's two (2) degrees of freedom,

24 revenue and revenue requirement.

25 MS. KELLY DERKSEN: It's -- it's late

1 in the day here. How about if I explain it in -- in
2 my terms and see if we can come together, here.
3 MR. JOHN ATHAS: Sure. I bet I'll
4 like that better than my terms.
5 MS. KELLY DERKSEN: We apply net
6 export revenue as an offset of cost. You could also
7 apply it to revenue. But however you apply it, there
8 is an impact either to revenue or to cost, however you
9 chose to look at it, that results in this outcome.
10 MR. JOHN ATHAS: Okay. So if -- if --
11 to maybe just -- to take it simple on me, so if I'd,
12 like, take a look at the first two (2) bars on the
13 chart, the blue and the green for residential, does
14 the residential rate class -- rate classes have the
15 same revenue in each of those cases that you've
16 modelled?
17 MS. KELLY DERKSEN: If you define
18 revenue to be only that which is collected through
19 rates then, yes.
20 MR. JOHN ATHAS: Great. I'm all set.
21 Oh -- that's it. Thanks a lot.
22 MS. KELLY DERKSEN: You know, I just
23 wanted to hopefully clarify one (1) -- one (1) other
24 matter that you previously raised with respect to the
25 -- the parallel that you wanted to draw regarding a

1 curtail -- a curtailable rate customer.
2 And one (1) of the challenges that's
3 you -- you might have trying to draw that parallel is
4 that with respect to a curtailable customer, you are
5 providing them a service, perhaps a lesser level
6 service, in which you were providing some kind of
7 offset in -- in terms of a discount to -- to their
8 rates to accommodate the fact that they're not getting
9 firm service at every point in time.
10 And from that -- in that kind of
11 service, you would expect that the terms of that would
12 be you would have some limited ability to curtail.
13 Certainly you'd define the periods, or how much that
14 you could curtail and over, you know, what periods,
15 whereas with an opportunity sales, which is the
16 parallel that you were trying to draw, you know, that
17 those sales are made from surplus energy, and they're
18 priced at whatever the prevailing market price of
19 energy is at.
20 So they're very different services.
21 I'm not sure that you could draw the parallel that you
22 were attempting to draw.
23 MR. JOHN ATHAS: I will proceed with
24 caution. Thanks.
25 MR. GREG BARNLUND: John, if I could

1 weigh in here for a second. I was listening with
2 interest to that discussion about interruptible
3 service, and Kelly had mentioned the allocation of
4 costs for setting embedded cost rates for
5 interruptible customers.
6 And I just wanted to bring an --
7 another analogy forward here, and I think that it's
8 maybe more analogous when we look at what we're doing
9 with opportunity sales on the electric side, which are
10 really sales of surplus electricity we have from time
11 to time, to what we do on the natural gas side with
12 capacity management transactions.
13 Our natural gas business, we hold
14 numerous long-haul storage -- or long-haul
15 transportation contracts on Canadian/US pipelines, and
16 we have storage contracts in Michigan. But we do have
17 the ability where we have periods of time throughout
18 the year where we don't utilize those facilities. We
19 don't have the requirements for them. We don't have
20 the load from them. We don't have to fill storage at
21 the same rate.
22 And so we will do capacity release
23 transactions to essentially sell off that surplus.
24 That surplus, there isn't an export class, but it's
25 credited back to all customers. There's no -- as long

1 as we're making a sale, meeting our -- our incremental
2 costs, we're not -- you know, we're not allocating any
3 fixed cost to that. The domestic customers pick up
4 all the fixed costs of the gas transportation assets,
5 and any revenues that we can obtain from them in the
6 competitive market, we're returning to those
7 customers.
8 And it's -- it's a more similar analogy
9 maybe to what we're seeing on the electric side of the
10 business in our opportunity sales, because those are
11 sales made into a competitive market themselves, and
12 they are different than how we would set embedded cost
13 rates for a domestic customer class.
14 MR. JOHN ATHAS: I would absolutely
15 agree that the -- that the positioning and mindset
16 that develop the gas rate is very similar to the
17 opportunity cost pricing in your proposal -- I mean,
18 our cost -- cost-of-service aspects of the proposal
19 that you put here. And I -- I just -- I just still
20 see a parallel to the electric side of -- of all the
21 arguments that were made about not giving full credit,
22 so that's all. I was just trying to understand.
23 Thanks.
24 THE FACILITATOR: One (1) of the
25 things for the last undertaking, am I correct to say

1 that that is to provide a table of the RCCs for slide
2 39 of the Manitoba Hydro workshop presentation?
3 MR. JOHN ATHAS: Correct.
4 THE FACILITATOR: Thank you. I'm not
5 -- not sure whether I should interject at all, but
6 during the last interchange, which was quite exciting,
7 I thought, show -- shows what my life is like, but --
8 but nonetheless, I -- I was a little bit concerned
9 that in some places, I think we were perhaps mixing up
10 a little bit of rate-making with cost-of-service
11 analysis, so I'm -- I'm a little bit concerned about
12 that.
13 But let's leave that. So we have not
14 much time for the -- the panel to ask questions. And
15 can I turn it over to any one of you?
16
17 (BRIEF PAUSE)
18
19 THE FACILITATOR: Good. Well, then
20 that means that the questions of the other parties
21 have -- have covered your questions, so that's very
22 good.
23 I did note that this morning in
24 particular, I was pressuring both Patrick and Bill to
25 keep moving for fear that we were going to run far

1 overtime. I wonder whether for any party but, in
2 particular, for them, are there -- are there questions
3 that you had that -- that I shut you out from that we
4 could try and cover a couple in the period till five
5 o'clock?
6 MR. PATRICK BOWMAN: I have a couple
7 short ones. Is that -- that's... On that last
8 undertaking, maybe -- the -- this is the presentation,
9 page 39. And this is just to confirm. As I
10 understand it, the blue bars is your PCOSS14 amended,
11 which is in evidence? Just to -- to confirm that. Is
12 that -- that's your normal PCOSS14?
13 MS. KELLY DERKSEN: I -- I wasn't
14 following which is in evidence. I agree that that is
15 the basis of the submission that we prepared. The
16 other analysis, I believe, to a large degree, if not
17 entirely, is in bits and pieces throughout IRs and --
18 and so forth.
19 MR. PATRICK BOWMAN: Right. That's
20 actually where I was going in terms -- in terms of you
21 having this data. The yellow, I believe, is the one
22 from MFR-4, so we have that filed?
23 MS. KELLY DERKSEN: Correct, yes.
24 MR. PATRICK BOWMAN: And -- and then
25 the -- the mauve, the final one, is the full 116/08.

1 I believe that's the same from Coalition 85F. Is that
2 fair?
3 MS. KELLY DERKSEN: Yes.
4 MR. PATRICK BOWMAN: Okay. And then
5 there's also a green and a red. And I think I may
6 have seen those. But if -- if somebody could let --
7 just let us know if those are -- are filed, if not, I
8 -- I don't need them filed. I just -- it'd be helpful
9 to have that cross-reference.
10 MS. KELLY DERKSEN: I believe the red
11 is for sure filed, I think in response to some of your
12 Information Requests, but the green, I'd have to
13 double check.
14 MR. PATRICK BOWMAN: That -- that's
15 fine. If you could just follow up with that, that
16 would help us to know the -- the details on that. One
17 (1) of the other questions you had on this last bit
18 was coming from PUB-70. I think it's page 7. So this
19 is the revenue requirement after Keeyask and MMTP come
20 into service. Pull that one up.
21 PUB IR-7. Yeah, that's the one. And I
22 think if we scroll down a little bit, you'll pick up
23 the -- the transmission. Okay, so if we're looking at
24 this, the -- the items that were reviewed in -- in the
25 NFAT as a -- as a development plan package primarily

1 relate to the Keeyask GS at 493 million revenue
2 requirement and the MMTP GNTL at 114 million.
3 Is -- I guess -- I guess, in -- in
4 fairness, in the -- probably the DSM, as well. But
5 that -- that's the package that we were really looking
6 at at NFAT. Is that -- is that fair?
7 MS. KELLY DERKSEN: I -- I think so.
8 I'm not sure what the inference there is, but, yes.
9 MR. PATRICK BOWMAN: And so -- but
10 it's a total of some -- somewhat $600 million in
11 revenue requirement. You -- you may quoted a higher
12 number. That's why I was -- I think you said 900
13 million, but you were probably including Bipole.
14
15 (BRIEF PAUSE)
16
17 MR. PATRICK BOWMAN: It's neither here
18 nor there. I just heard you say nine hundred (900),
19 and I was -- just wanted to cross-check that.
20 MS. KELLY DERKSEN: You -- you know, I
21 believe these are the annualized costs.
22 MR. PATRICK BOWMAN: Right, yeah.
23 MS. KELLY DERKSEN: And I was talking
24 from a total investment perspective, I think.
25 MR. PATRICK BOWMAN: Okay. But the

1 annualized costs, you're -- we're really talking 600
2 million. And if this cost-of-service method is going
3 to be applied when those come into service, there will
4 be $600 million in revenue require hitting the books
5 in advance of the years where those projects are --
6 are being used for domestic service.
7 If -- if Keeyask costs and -- and
8 MNTP's costs are being allocated to dependable exports
9 with very little to the opportunity, only the -- the
10 surplus, only the -- the water rentals and the like,
11 the variable costs, it won't end up allocating
12 anywhere near $600 million in costs to the export
13 class as a result of bringing those assets on.
14 Is that fair?
15 MS. KELLY DERKSEN: Fair from the
16 perspective that that investment has been put in place
17 to serve Manitoba load, yes.
18 MR. PATRICK BOWMAN: Oh, I'm -- I'm
19 say is it -- is it fair as it mathematically 600
20 million will come into the revenue require side, but
21 something less than 600 million will -- will be
22 considered -- will be allocated to the export class
23 when those assets come on?
24 Mathetically, that -- that would be in
25 relationship what I understand.

1 MS. KELLY DERKSEN: We have
2 approximately order of magnitude of $10 billion in net
3 -- in -- in investment coming online over the course
4 of -- of a number of years upcoming. Rough rule of
5 thumb is something a little bit less than 10 percent
6 of that can be assumed to be the -- the revenue
7 requirement impact of that in a particular year.
8 Part of that 10 percent would be
9 allocated to dependable exports. Of course, this is
10 caveated fairly extensively because, you know, whether
11 that full revenue requirement comes in in that manner
12 in that year is -- is subject to a fair amount of
13 discussion.
14 MR. PATRICK BOWMAN: Fair enough, but
15 this is the numbers you put together for the revenue
16 requirement for '20, '21, '22 with these projects
17 coming online. And around 600 million of that revenue
18 requirement is related to Keeyask and the cross-border
19 transmission, which is part of the advancement we
20 talked about at the NFAT.
21 MS. KELLY DERKSEN: Yeah. Yeah,
22 that's -- that's about the math, yes.
23 MR. PATRICK BOWMAN: Okay. The other
24 question I had, and I think it might go to the
25 Christensen question, there -- there was this last

1 discussion about interruptible and how one would
2 allocate costs to off-system surplus sales,
3 interruptible or opportunity sales, and the extent to
4 which, if you were in a different jurisdiction --
5 Georgia I think was the reference that was made -- you
6 might have a plant that was built for domestic
7 purposes.
8 But you may find an opportunity where
9 your plant is not being fully utilized. Perhaps it's
10 not a peak time. And you can make some -- it could be
11 in the money. You could make some sales, see a small
12 amount of -- of margin from that, and that would be
13 allocated, you know, possibly some fixed costs,
14 certainly variable costs, but primarily variable
15 costs.
16 Is that -- is that fair, what we're
17 talking about with the off-system opportunity sales
18 for the -- that type of -- of example?
19 MR. ROBERT CAMFIELD: Yes. The -- the
20 evidence is mixed.
21 MR. PATRICK BOWMAN: Okay. But the
22 idea would be you've -- you've built a plant. It's
23 the same plant you would have built with or without
24 that -- that future revenue coming from those
25 opportunity sales, and you just get the chance to use

1 it to capture some margin.

2 MR. ROBERT CAMFIELD: That's correct.

3 MR. PATRICK BOWMAN: And I guess the

4 question --

5 MR. ROBERT CAMFIELD: Presuming we

6 have excess capacity I think is implicit in your

7 question, yeah.

8 MR. PATRICK BOWMAN: Yeah, yeah,

9 Presume you have excess capacity. That's fair. And I

10 -- I just want to just go to a point which is in --

11 that to me is a very different situation where you

12 would have a plant that's committed.

13 It'd be the same plant with or without

14 those opportunity sales. The business of that plant

15 probably is developed without assuming those -- those

16 opportunity sales would arise. And it just really

17 becomes a situation of maybe they'll be in the money,

18 maybe they won't, and you'll make your best decision

19 as the time arises as to whether you're in the money

20 and make the sale. And making that distinction

21 between something like a -- a Keeyask where those

22 opportunity revenues were inherent to the business

23 plan, and absent those opportunity revenues a

24 different investment decision might have been made.

25 And I was just wondering if you wanted

1 -- if -- ca, sort of -- you want to comment on -- on
2 that difference in terms of -- of opportunity and the
3 role it plays in -- in the investment patterns?
4 MR. ROBERT CAMFIELD: Yeah, and I
5 think the distinction that you're making is one (1) of
6 well, we have an opportunity and so let's take
7 advantage of -- of it in the case of advantage going
8 to Manitobans in the -- in the long run, on the one
9 (1) hand. And then the other, an opportunity coming
10 up rather randomly.
11 MR. MICHAEL O'SHEASY: Well, let --
12 let me also add there's -- there another, I think,
13 analogy here. In my experience with the southern
14 company -- southern company is, it would -- well, say
15 Georgia Power -- is it would grow its domestic load.
16 It would know that a certain date in the future it was
17 going to need plant to serve it. However, it -- it
18 also knew that it had an opportunity earlier than that
19 to make some money by selling the power to another
20 utility.
21 So they entered into what we call a
22 'unit power sales contracts', UPS for short. And they
23 would basically build the unit earlier. They would
24 construct it, put this plant in service earlier than
25 it was needed for domestic purposes, and they would

1 sell the power then down to Florida, like Florida --
2 Florida Power and Light. And they would charge them
3 fully loaded embedded costs for that power, as well as
4 variable cost, and collect the margin -- the uplift
5 from those sales to Florida Power and Light.
6 And those UPS contracts would have a
7 termination date to it. They would -- they would
8 basically diminish over the course of maybe ten (10)
9 years, and then that plant would come into service for
10 domestic purposes at a much lower cost and the utility
11 would have been collecting margin over that course of
12 time.
13 MR. PATRICK BOWMAN: Can I just
14 clarify? In that type of situation, first of all,
15 those would probably be thermal plants?
16 MR. MICHAEL O'SHEASY: Yes, they were
17 thermal plants.
18 MR. PATRICK BOWMAN: So -- so --
19 MR. MICHAEL O'SHEASY: Georgia Power
20 has very limited hydro capability.
21 MR. PATRICK BOWMAN: Right. So when
22 you'd enter that contract, first of all that -- that
23 contract then, would -- would that have been for a --
24 a firm type of power or -- or relatively firm, some --
25 something more than what -- what we call opportunity

1 here?

2 MR. MICHAEL O'SHEASY: Yes, they --

3 they would have firm, but to the extent that the plant

4 itself was built greater -- at a size greater than

5 that other utility is willing to buy. They might have

6 anticipated that there were going to be some economy

7 sales out of it also --

8 MR. ROBERT CAMFIELD: And, Michael,

9 you're referring to sharing report -- FP and L?

10 MR. MICHAEL O'SHEASY: Correct.

11 MR. ROBERT CAMFIELD: Yeah.

12 MR. PATRICK BOWMAN: And -- and the

13 other question, would -- would those sales to Florida

14 have been sufficient to cover the annual revenue

15 requirements associated with that plant when it comes

16 into service?

17 MR. MICHAEL O'SHEASY: And -- and more

18 so. Yes, and more so.

19 MR. PATRICK BOWMAN: And more so?

20 Okay. Okay. I want to think about that one (1)

21 overnight, but that's -- that's helpful. Thank you.

22 That was all for supplementing today.

23 MR. BILL HARPER: I -- I just had a --

24 kind -- kind of a small point. And this one (1) has

25 to do with Coalition number 24C. And actually, I'm

1 trying to put -- actually this was where there was a
2 reference to the fact that there were opportunity
3 sales -- they could get into opportunity sales that
4 involved the sale of capacity, which certainly as
5 we've been -- a little bit of a break from our normal
6 -- normal paradigm of thinking as dependable sales as
7 being the ones that involve sort of firm commitments
8 and opportunity sales being the ones that are just
9 sort of, you know, get as we can with -- with no
10 commitment.
11 And so I'm just wondering if you'd just
12 ex -- maybe just clarify that a bit and explain under
13 what circumstances you might involve -- get yourself
14 involved in an opportunity sale that involved the sale
15 of capacity, and whether that would actually involve a
16 commitment of dependable energy. Or whether just the
17 fact that it's an opportunity sale with just a short-
18 term basis and you know you have so much energy on the
19 system or the system is such that you -- you can make
20 that commitment even though you don't have the
21 dependable energy to back it up.
22 I'm just trying to understand how that
23 -- how that opportunity sale with capacity works and
24 how it fits in our definition of dependable versus
25 opportunity sales on a broader basis.

1 MR. DAVID CORMIE: Mr. Harper, the
2 MISO capacity market, the product that is sold are
3 called ZRCs, zone of resource credits. And they're --
4 that's because it's done through the auction and, you
5 know, we -- we can sell that capacity for five (5)
6 years.
7 And if we got into the situation where
8 that would result in us being capacity short, we would
9 go back to the auction and buy our way out of that.
10 So in -- in effect we'd just financially committed to
11 -- there's no physical delivery obligation.
12 MR. BILL HARPER: And those would be -
13 - sorry, and that's what you'd be talking about here
14 in terms of an opportunity sale that involved
15 capacity.
16 MR. DAVID CORMIE: Right. Or -- and -
17 - and historically we've entered into many seasonal
18 capacity contracts that -- that there's no risk that
19 we would have to build for those where there's lots of
20 risk associated with a twenty (20) year sale because
21 of uncertainty with load growth.
22 But, you know, in -- in -- there's many
23 years in the past where we've entered into short-term
24 capacity and -- and energy contracts that's generated
25 demand charges as well as -- as energy charges. And

1 so the -- it's -- it's not -- except that in those
2 contracts there's always an obligation to make
3 physical deliveries.
4 In those ERCs we can go back to the
5 auction, and there's some financial risk that you
6 might have to settle at -- at a loss but there's --
7 we're -- that will always be cheaper than having to --
8 to build capacity for that, right, because they're
9 very -- they're very short term in duration relative
10 to the other long term sales where the customer
11 doesn't want to financially settle. They -- they have
12 avoided building plant, assuming Manitoba Hydro will
13 have that plant in place and physical delivery is
14 required.
15 So that's the difference between those
16 --
17 MR. BILL HARPER: No, no, fine. Thank
18 you. I think that was really the only point, I think,
19 I missed in my earlier questions. Thanks.
20
21 (BRIEF PAUSE)
22
23 THE FACILITATOR: Paul, how about one
24 (1) question? I hope.
25 MR. PAUL CHERNICK: This is a question

1 that doesn't require actually looking at any documents
2 for a change, and -- and that is in I believe three
3 (3) of the responses to the Board there were
4 references to confidential documents -- confidential
5 attachments, or there was data redacted. And my
6 question is: Is there any opportunity for other
7 parties to get access to those data?
8 The -- a couple of them have to do with
9 prices for the exports, and PUB-16 -- let me just
10 check what that is.
11
12 (BRIEF PAUSE)
13
14 MS. ODETTE FERNANDES: Mr. Chernick, I
15 can just respond to you. No, there is no opportunity
16 in this process that has been established for
17 Intervenors to review confidential information. That
18 confidential information has been filed strictly in
19 confidence with the Board.
20 MR. PAUL CHERNICK: And is there any
21 reasons why we couldn't sign a confidentiality
22 agreement, and -- and see that? I -- I know that you
23 say it hasn't been established yet, but these are
24 routine documents.
25 MS. ODETTE FERNANDES: I don't agree

1 that they're routine documents. Some of these --
2 MR. PAUL CHERNICK: Well, routine
3 every place except here.
4 MS. ODETTE FERNANDES: These documents
5 are very confidential and privileged to Manitoba
6 Hydro, and prior to releasing that information to
7 anyone but the Board Manitoba Hydro would need to
8 reassure itself that there are restrictions in place
9 in terms of those documents. And I don't believe that
10 can be quickly done in a process such as this.
11 MR. PAUL CHERNICK: Well, you've known
12 that this process was coming up for a long time, and
13 there are jurisdictions all across Canada and the US
14 in which utilities provide not just prices but the
15 details of their contracts --
16 THE FACILITATOR: Paul --
17 MR. PAUL CHERNICK: -- to Intervenors
18 on a regular basis.
19 THE FACILITATOR: Paul, if I can
20 interject. I -- I think this issue is one outside of
21 the workshop materials here that if you wanted to
22 petition the Board separately that would --
23 MR. PAUL CHERNICK: Okay. I just
24 wanted to get that straight.
25 THE FACILITATOR: Thank you. Well,

1 thanks everyone. It's -- it's a delight to be done at
2 five o'clock for fear -- the fears I had at the start
3 of the day. Tomorrow we will have the even more
4 exciting matters with respect to transmission, so I
5 look forward to seeing everybody at nine o'clock
6 tomorrow morning. Thank you.
7
8 --- Upon adjourning at 5:01 p.m.
9
10
11
12 Certified correct,
13
14
15
16 _____
17 Sean Coleman, Mr.
18
19
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