DATE/TIME	June 18, 2012 9:00 a.m. – 5:00 p.m.
LOCATION	Sandman Vancouver City Centre Moxie's Ballroom 180 West Georgia St., Vancouver, B.C.
TYPE OF MEETING	Meeting of the BC Hydro Integrated Resource Plan Technical Advisory Committee (TAC). TAC is a group of knowledgeable participants with significant interest, stake, and experience in BC Hydro's resource planning process assembled to provide detailed, technical input and feedback to BC Hydro during the development of the IRP.
FACILITATOR	Kenna Hoskins, BC Hydro
PRESENTERS	John Duffy, BC Hydro Lindsay Fane, BC Hydro Kathy Lee, BC Hydro Randy Reimann, BC Hydro Mike Savidant, BC Hydro Jim Scouras, BC Hydro Basil Stumborg, BC Hydro
ATTENDEES TECHNICAL ADVISORY COMMITTEE MEMBERS	Doug Chong, BC Utilities Commission David Craig, Commercial Energy Consumers Tom Hackney, Sustainable Energy Association of British Columbia John Lawson, First Nations Energy and Mining Council Peter Ostergaard, Ministry of Energy Jim Quail, Canadian Office & Professional Employees Union (COPE) Local 378 Randy Reimann, BC Hydro Tom-Pierre Frappé-Sénéclauze, Pembina Institute Richard Stout, Association of Major Power Consumers Jim Weimer, Clean Energy Association of BC Paul Wieringa, Ministry of Energy (departed 1:47 p.m.) Jason Wolfe, FortisBC **REGRETS:** Bill Andrews, BC Sustainable Energy Association Robert Duncan, First Nation Representative
MEETING OBSERVERS	Linda Dong, Dong & Associates Nicholas Heap, CANWEA

ATTENDEES BC HYDRO	Amir Amjadi, BC Hydro Trudy Kwong, BC Hydro Susan Campbell, Recording Secretary, Corporate Consulting

MEETING MATERIALS

- Agenda for TAC Meeting #6
- Draft IRP and appendices

Note: copies of all reports are attached and filed with the agenda materials from the meeting.

1. Welcome, Review Agenda and Meeting Objectives – Kenna Hoskins

The Facilitator, Kenna Hoskins, welcomed everyone, reviewed the agenda for the Technical Advisory Committee meeting #6 and reviewed the meeting objectives. She explained the purpose of this TAC meeting was to introduce TAC members to the draft plan, provide clarifications and promote understanding in preparation for providing written comments, attributed to individual TAC members.

Participants were advised that the deadline for written submissions by TAC members was August 10, 2012. July 6, 2012 was the deadline for public consultation input and August 13, the deadline for First Nations input.

2. Overview of Draft IRP – Randy Reimann

(The record notes that, in all cases, the following abbreviations will be used and mean: Q: Question, A: Answer, C: Comment. Further, all questions and comments are from the meeting participants and Answers are from the BC Hydro Team)

Overview of Policy Context and Recommended Actions

Randy Reimann provided a high level overview of the draft plan (Ref: Power point presentation slides) and addressed TAC members' questions to clarify the draft plan.

Purpose of IRP – Slide 6

Q: It seems odd to develop a 30 year plan without the corresponding 30-year transmission portfolio runs. Why is that?

A: We do 20 and 30 year portfolios and identify the associated transmission needs and we ask, do the transmission needs change looking out 30 years? As well, we are taking into account likely generation development.

Q: Why do you only go out to 20 years for some portfolios, versus 30 years for all portfolios?

A: Computer modelling runs looking at 20 years can take a day. To do 30 years could take up to 5 days, so it's about computing capabilities. We do compare the 20 and 30 year analyses and the transmission analyses don't show a lot of differences.

C: There is greater uncertainty around 30 years. We are trying to focus on actions today and not foreclose on any future plans.

C: There are dramatic changes in the 5 year period. The importance is to build flexibility into the plan to deal with key decisions in the short-term. Looking back we saw a recession that crashed around us and changed all the forecasts.

Q: What is your understanding of the requirement that the plan be filed every fifth year? Will you need Cabinet approval to update the whole plan?
A: Yes. There is a provision in the Clean Energy Act (CEA) whereby you can update part of the plan in between five years.

Clean Energy Act 16 Objectives – Slide 9

C: With respect to the 66% requirement, your option with initial LNGs did not meet that requirement. We haven't seen a lot of analysis around that.

Q: The 66% and 93% numbers—what is the basis of those numbers? They appear arbitrary.
A: The 66% and 93% objectives are in the Clean Energy Act. I couldn't agree with the word 'arbitrary'. Government has a desire to see less GHGs emitted.
C: Do you know the amount of GHGs associated with each percent?Those sensitivities would be interesting.

Energy Forecast – Slides 13 to 18

C: Because you define rate design measures and DSM, it seems you can easily say you have achieved the target.
A: Within the plan, you can look at the options we explored and how we got to Option 3. We identified all the cost-effective DSM we thought we could deliver on and it doesn't meet 66%. The target was defined before LNG loads were identified. Eventually as load grows – you run out of DSM potential.
C: So you're saying 66%, provided it was cost-effective. There are really two caps: 66% or something lower if it doesn't prove cost-effective.
A: This is about objectives and what we understand the government is looking for; with respect to DSM we can't get any more than what we think we can deliver on.

Q: It assumes renewables are cost-effective, but let's say burning natural gas is more cost-effective then can you argue an 80% clean target is more cost-effective?
A: I am happy to receive your comments in writing – almost all the portfolios created achieve the 93% objective and we believe that is what government wants.

Q: I'm interested in trade-offs – the Clean Energy Act is written for single metrics and I think it should be carrying trade-offs with it. To the extent of your models, have you looked at the question of what the GHGs are and whether you have internal criteria you are looking at?
A: We can give clarifications today why we landed where we landed; I will take your comments under consideration and see if any further clarifications are needed in the plan.

Q: It is odd that LNG will pay all incremental costs because there are other tariff approaches that could have been taken. The LNG strategy said all plants pay all incremental costs, is that right?
A: Yes all three pay all incremental costs. That is the direction we followed from the government's LNG strategy.

Q: With respect to the LNG plants – how sure are we that those plants will go ahead?
A: It is still in negotiation.
C: This is good policy you are pursuing with regard to LNG.

Conserve More – Slides 19 and 20

Q: If regulations change, do you count those changes as DSM or adjust the load forecast? You have a DSM utility-funded program, yet rate design and government regulations are not utility regulation.

A: It is counted as DSM. It also counts as DSM when there are changes to legislation. 'DSM' is a broad definition.

Q: You are taking the broadest possible interpretation of DSM. Right?

A: It involves a conscious action of government/utility to increase conservation; by contrast, evolution of technology is not a conscious action.

C: The 'B' recommended action is very positive. These are higher level strategies and prepare for greater demand. I encourage you to look at greater flexibility to allow for changes.

Q: Codes and standards being part of DSM make sense – could you separate what is within BC Hydro's purview and what is part of government policy?

A: We do have a program and we will get to that issue in the afternoon.

C: You could use Smart Meter technology to deliver device control. On another note, thank you for listening to the industrial customers around interruptible programs; they are a form of tariff control.

Q: There is increased importance placed on capacity – what are the drivers? Is that due to renewables and do we need more capacity to balance?

A: We are still looking at the ability to integrate resources; renewables make a bit of a contribution to capacity and integration capability is part of it.

Q: What is included in the capacity savings?

A: For DSM capacity numbers, we refer you to Chapter 9 – there are 477 megawatts in total--286 megawatts for industrial load curtailment and 191 megawatts capacity programs (all three rate classes except transmission).

C: Add commercial customers to what we want to pursue by way of interruptible rates; I suspect that this could be a bigger contribution to what we have got.

Build and Invest More – Slides 21 to 25

Q: Have you spoken with Mr. Ruskin, former BC Electric engineer? He says that there are plans in the archives around the Columbia River and he believes BC is looking at the wrong river (Site C)—we should be looking at the Columbia. If that analysis has been done, it might be useful.

A: Yes, we have looked at capacity upgrades for Mica and Revelstoke.

C: That said, we want to ensure that we are not overlooking some very good resources; we need to prove or disprove those claims. BC Hydro is the only entity that can look at that and we think BC Hydro should produce a report.

Q: Could you extend the Burrard Thermal operation for low water conditions? I don't know the difference between emergency situations and running it during droughts. I don't think there would be a noticeable difference and it could reduce the energy you plan on purchasing.

A: By regulation, we can only use it for capacity purposes, not energy. Burrard runs during a winter cold snap and typically runs 12 days a year.

Q: Are there contractual conditions around pursuing power in the market?

A: That hasn't been specifically addressed by way of policy – you can buy capacity options in the marketplace. With respect to the Columbia River Treaty and the Canadian entitlement, 1,200 megawatts can be delivered to the BC border and that provides a back-up option.
Q: How dispatchable is that?
A: At least a day ahead, maybe a little further ahead.

Q: What is the time frame for the procurement call?
A: The launch of an acquisition process is targeted for the latter part of 2013.

Q: That cuts the time very short if you need this energy by 2016 or 2017. Have you given thought as to how quickly you can do this?
A: The intent is to start discussions this year.

Prepare for Potentially Greater Demand – Slide 26

C: With respect to the LNG plants, another option is to just go to gas and then you won't need transmission and wouldn't need renewables to be backed up. What do you consider the three potential LNG plants?
A: Notionally, the third is the Shell partnership, but there are other groups expressing an interest and we will address that as they come in.

Q: There is interest from government in displacing gas with electricity; presumably customers like electricity – is this another instance where customers pay the full incremental cost?
A: Potentially.

Q: Has BC Hydro evolved its thinking more broadly about GHG reductions for northeast BC?
A: Yes, there is a section that looks at the Horn River basin; it looked at a range of options.
C: The irony is that every carbon molecule extracted ends up in the atmosphere no matter how we use it.
C: This is about cost trade-offs of electrification or gas. It shouldn't be GHGs at any cost. I encourage BC Hydro to do the calculations and get into the discussion around the trade-offs. BC Hydro needs to do the calculations and provide the information to government.
C: You have to make calculations and make economics matter around GHGs. Economic criteria in the Clean Energy Act would have to go into the plan and would have to consider that. GHGs have to be limited and clearly the Act is not restricted to electricity.
A: In the plan we are meeting the target of 93% and we have undertaken the analysis out to 2050 and modelled what likely electrification might happen. We need to continue to work with government on that front.

Pumped Storage - Slide 28

C: One of the big issues with pumped storage is the variation in levels of the reservoirs – they aren't efficient and there are lots of other energy storage schemes that are more efficient.
C: I'm happy to see pumped storage in the sense that it is a physical system option and provides a marginal cost to compare against. I'm not expecting you to go ahead and build one unless there are no other options.

Action Plan Alignment with Base Resource Plan Scenarios - Slide 32

Q: Something that would be useful is a critical path and the time lines involved and then the gaps.
A: Good idea.
Q: What about the "doom and gloom" scenario? Which plan is flexible enough; that is not clear enough.

A: That is the left column "Action Plan without initial LNG" on the table in Slide 32 .

C: I second that a time line would be very helpful.

C: Government policy will inevitably change so the scenario that provides the most flexibility will be the most important.

3. Navigating Chapters 6 and 9 – Kathy Lee, Basil Stumborg, Lindsay Fane

Using the draft IRP and focusing on chapters 6 and 9, Kathy Lee, Basil Stumborg and Lindsay Fane, supported by other BC Hydro staff, addressed TAC members' wide-ranging questions designed to clarify the contents of the draft IRP.

Page 6-9

Q: The line represents getting to 93% - what percentage are we at zero on the bottom axis?

A: Looking at the load forecast after DSM savings in fiscal 2017, the load is about 65,000 GWh and 7% of that (available for gas) is about 4550 GWh. In this section it also describes existing thermal resources with planned energy contribution totalling about 3,500 GWh. So, 4550 minus 3500 is about 1000 GWh room for gas.

Page 6-20

Q: Is the 18% average, or minimum? Is there something about the economics of running a peaking plant? What about cost-effectiveness?

A: The assumption is, if we plan on gas generation, we would want it to be able to generate at least 18% capacity factor and still meet the 93% objective.The 18% is based on hours needed for peaking for planning purposes, it has not factored in economics.

Q: If we could use more gas, shouldn't we see the analysis? Why wouldn't you create a comparison portfolio?

A: We have shown gas costs on a dollar per megawatt hour basis. We are happy to take the comments.

C: One of our concerns is around the price of gas-fired generation and saying it is too high, as in Scenario C. At Fortis BC when we do the analysis, we have a hard time getting that high gas price.

Q: Can you clarify the cost of gas? $5.5 is used in the modeling and it varies over time.

A: Chapter 4 – Page 24 – Figure 4-6 shows that the gas price assumption ranges from $4 - $5 over the planning period in (BCH Low) Scenario C which is the base/most likely scenario. This is the lower end, higher prices were also tested in other market scenarios. On Page 6-12 Table 6-1 summarizes the dollars per megawatt hour for different market scenarios.

Q: Have you ever done a retrospective analysis of gas forecasting? My impression is that there is a significant tendency to over-estimate.

A: What you are asking for is a feather duster picture – ranges of forecasting over time. I haven't seen that analysis done for gas pricing. The goal of the scenarios was to come up with a broad range so as not to be surprised.

Q: Do you still use the consultant, Gordon England? He was nearly always the lowest with estimates and the most accurate. For policy discussion purposes, the most accurate picture is needed.

A: I am not sure if we are using that consultant or not. Again, our goal would be a wide-range of prices so that there are no surprises.

Q: Do the scenarios capture and reflect world-wide LNG pricing?

A: That was before shale gas really came on line, so this is what gas prices would look like in North America without shale gas.

C: That is Scenario A; however, the other extreme should be shown as well. While you can't go beyond 93% you can still show government what the scenario looks like.
A: We had not intended market scenarios to reflect spot market pricing; we have no expectation that prices will stay down at $2.50. Figure 4-6 has that forecasting information. We are hearing that while LNG will not go to a world-wide market price, it will rise.

Q: Table 6-1: What are the dollars per megawatt hour? How much of the capital cost of the plant is in there? Confirm that capacity credit is in there.
A: It includes operating and capital costs, all in. Portfolio analysis does not use unit energy cost. Numbers in this table have been adjusted as in the Clean Power Call – levelized cost adjusted to Lower Mainland. Capacity credit/adjustment is embedded in numbers but don't have the numbers right now. Request noted.

Action: Clarify what is in table 6-1 page 6-12.

Q: Assuming all at same location at Kelly Lake?
A: Yes.
Q: My question is on heat rates. When the gas-turbine is ramping up and down, what heat rate are you assuming?
A: Model assumes same heat rate.
C: That is a serious error– heat rate is significantly degraded if the plant is in back-up mode. This is similar to the question around the decision making on the margin and needs to be reflected in the plan. When LNG gets going to connect supplies to market the prices will in the long term be less than $4.
A: When there are inaccuracies, it only affects the last unit in.

Page 6-17, Table 6-4

C: I see that this is predicated on 7%. Is there a credit for gas turbines that can avoid transmission expansions? In what way have you recognized the economic advantages of gas turbines?
A: We haven't quantified the credits, but we have recognized it.

DSM: Page 6-32

Q: In the DSM portfolios, are you breaking down activities between industrial, commercial and residential levels–will there be differences between the groups?
A: The five options have activity in all sectors. Generally, balanced in all three sectors for all five options; the question is, what is the best way to get at that level of savings?

Q: DSM: Page 33 – fiscal 2014-2017: Why wait that long?
A: We asked for and received approval for 2012 and 2013 DSM expenditures, so the IRP is set up to start after that. We will be asking for approval in 2014.
Q: Will BC Hydro be filing a new expenditure request for 2013 on?
A: 2014 on.

Q: Is there uncertainty around what the Commission approval or is the uncertainty around the technology?
A: We did not include risk around the Commission approving.
C: Suppose planning includes a transmission line and you have a certain timeline and yet you can't get the transmission line built in that timeframe because of regulatory difficulties, are there alternative scenarios? Maybe the same thing applies to DSM.

Q: Bill 32 – where is it at? What is the relationship between IRP and moving forward?

A: The Act has been held over to the fall – It is about replacing the energy efficiency act and creating new powers. It will allow government to expand energy codes and standards. All IRP options were developed prior to the implementation of the bill.

C: Note: there is a risk of the regulator going in a different direction. The Commission must consider the most recent IRP approved by the government and that is the equivalent of going through a process and approving it. The loop is intended to be there and BC Hydro should assume it will receive approval.

C: 6-10, page 6-31: It only rises up to $40 megawatts. Is that bundled? How high is the high end?

A: It is average cost. The high end on the margin it is up to $130-$140 per megawatt hour and is captured within the limit of cost effectiveness. There are measures in Option 3 not included in Option 2. The options were constructed for the purpose of the analyses.

C: I don't agree with comments around the Clean Energy Act. BC Hydro cannot expect the plan to fail and it can't foresee political changes.

C: BC Hydro should contemplate regulatory risk and recognize and plan for that in a timely fashion. We have already seen massive changes in the Act. The plan should have enough information in it to operate robustly.

A: We have looked in the plan with respect to uncertainty around DSM deliverability and we have contingency plans for that. We want to commit to those things today to keep the options open for future supply and only commit to those things we have to do in smaller dollar amounts.

C: I support keeping options open. You're not keeping enough options open.

Page 6-10

Q: Figure 6-11: Is that total resource cost?

A: Total resource costs net of benefits including non-energy benefits.

Q: Including benefits that BC Hydro doesn't see?

A: Correct. In February's TAC meeting, we showed a view with all costs, a view including non-energy benefits from the recent legislative change (15% non-energy benefits).

Q: Has the rate payer impact not been shown?

A: Figure 6-13 is the closest comparison to that. Average rates may increase, but total costs for utility can decrease. While utility cost decreases, because of DSM savings it may have fewer customers to pay, so average rates could still increase. Option 3 may have average rate increase, but we're expecting rate savings.

Q: 2% increase by when? Is that over 20-years?

A: 2% difference between Option 2 and 3 by 2020. It's 2% of today's rate.

Q: That is confusing–lay it out by year. One of the objectives is to contain rate increases and maintaining that is hugely important.

A: BC Hydro will only present cost comparisons. We haven't landed on a long-term rate forecast.

C: It is very important to get the other side out for participators and non-participators. It's important to have both sides embedded in the present model. Government's impetus on competitive rates is based on single measure metrics; you don't have trade-offs accompanying them.

RESPONSE TO EARLIER QUESTION*: Heat rates for gas – Table 6-1 are: at 9.2 GJ/MWh for SCGT and at 7.58 GJ/MWh for 50 megawatt CCGT and 7.35 GJ/MWh for 250 MW CCGT. Capacity credits are $6 per megawatt hour for CCGTs and $20 per megawatt hour for the SCGT.*

Lunch Break

The Facilitator observed that the meeting was behind schedule and asked what areas members would like to discuss in depth. With respect to the Site C discussion, TAC was advised that Mike Savidant would be back between 3:00 p.m. and 3:30 p.m. The Site C discussion would be inserted then. After discussion, it was concluded topics to be covered in the afternoon should include near-term capacity, acquisition, north coast, Horn River and the north east, transmission (gas and management of uncertainty as contingency) and Site C.

Near-Term Capacity Page 6-143
Figure 6-29

Q: In the graph – year 2022, mid gap post DSM, IPPs and Site C only showing a drop of <1,000 megawatts.
A: Site C with 1,100 megawatts installed capacity shows up with <1000 MW after factoring in reserve requirements.

Page 9-46

Q: What are the alternatives at that pace?
A: For the near-term capacity gap, as discussed in Chapter 6, the only reliable alternative would be gas. If we use gas now, we are foregoing the future option so we recommend a bridging option.

Q: The Columbia River Treaty – it seems to me that would be a No. 1 option to exercise those rights. Then Burrard Thermal is there all ready to go, only the incremental cost is high. I think the Columbia River Treaty is the first option, then extending Burrard Thermal and market purchases.
A: Notionally, we go to the market first and use the security of the Canadian entitlement, then we would use Burrard Thermal last. There is not a lot to be traded off between the market and the Canadian entitlement. The intent is to use Burrard Thermal last and that is consistent with the Act.

Q: Pumped storage is also an option – isn't there about 500 MW potential at Mica?
A: The gap is in the short term and this resource isn't available in time. Also the cost is a consideration as well – pumped storage is higher, over $100/kW-yr and that hasn't accounted for the cost of energy. Table 6-32, Page 6-137 references this.

Q: Is the main driver the LNG plants?
A: Yes, but we do have a capacity gap without any LNG.
Q: What about LNG producing their own curtailment?
A: Load curtailment doesn't work with LNG, rather their process comes on and runs steady.

Q: I would like some clarity around 2,000 MW and the 1,200 MW from the Canadian entitlement. Both come across transmission lines.
A: US – BC import capability is 3,000 MW (thermal rating), currently approved rated at 2,000 MW but depending upon operating conditions, it is usually less. Practically speaking, we need the capacity during the two-week cold snap and we feel comfortable at 500 MW but it may be more – the congestion (constraint) is along the I-5 corridor near Seattle (and not the US-BC import line).
Q: Alberta intertie – capacity coming in?
A: Same problem, capacity is limited as we are in cold snaps at the same time.

Contract Acquisitions – Page 6-89

Q: Have you given any thought to the option that customers might voluntarily be prepared to degrade energy certainty? Some large customers might take that gamble based on a price cut. For planning purposes you've assumed one-size fits all, but BCH could assume some customers may accept more risk.

A: We have not made that assumption but we can take that comment.

Q: Where does the 2,000 GWh come from? And, 1,500 GWh, where is that coming from?

A: 2,000 GWh clean acquisition and 1,500 GWh from market – yes. Energy gap before Site C grows to about 3,500 GWh, BC Hydro believes that an additional market reliance of 1,500 GWh for a short period would still result in a reliable system and would save cost, thus recommended that action. The remaining gap of 2,000 GWh is recommended to be filled with clean acquisitions.

Q: Are you talking day-to-day or month-to-month? (This in reference the earlier question regarding asking customers to assume higher uncertainty.)

C: Either would be fine depending upon the customer; it is not for everybody and not for a pulp mill.

C: The risk is if you take energy from the market. If you spread that around in industry and commerce, the risk is near zero and your price is a very nice reward for those parties that assume the risk.

A: This is an interesting suggestion and we will take a look at it.

C: There are several other discussions we could have around the gas option and it is a good technical piece to be looked at.

North Coast
Page 6-52 to 6-56 (Table 6-11)

Q: Are you not considering the gas option because that would violate the 7%?

A: Yes.

Q: In Option 'A' going from clean energy – what is the assumption and at what cost? Gas capacity – is it assumed to be SCGT? I need to get clear what you are doing here.

A: It is a mix – some from other regions but mostly local (other north coast resources). I would refer you to Appendix 6-A. There are trade-offs and we are looking to a number of options around supply and we expect the cost to be cheaper system-wide.

Q: Are all the assumptions documented?

A: This is a high level assessment and we are keeping both options alive. The cost of the transmission line is about $1 billion.

Q: Supply Option A – mix of clean energy and gas?

A: Yes, gas peakers only and SCGTs. The details are shown in Appendix 6-A.

Q: I'm surprised about building combined cycle. When is the third plant expected to need power, how long would it take and do the timelines match? Only 6 years—have you noticed how long it takes elsewhere. Is that creditable for LNG plants?

A: Fiscal 2019 and 2020 for LNG. End of 2018 for transmission line. Obviously there is much detail and discussion to come.

C: I don't think they will believe that the transmission line is optional and I don't think they believe Option A either – compared to what else is in the world. There are so many things that don't jibe.

C: It is all evolving and not firmed up. Is the 500 kV coming into service in Option B, N-1 with transmission in additions?

A: With one segment out you can still serve a lot of load; that is what the transmission planners tell me. Voltage stability of the line is very important.

Q: Option A – single kV line with gas back-up. Designed to N- 1?
A: We could lose a thermal unit and carry on but we could not lose generation.
C: I support the recommendation, but just asking for more information.
C: Worth putting in recommendation text – target volume is 10,000 GWh a year.
C: Is a transmission line amortized over five years? How many years of stranding is that? Isn't that a bigger problem? That causes me concern unless Shell literally pays for the transmission line.

Q: What is the amortization period for transmission?
A: Generally 40 yrs
C: Generation from north coast was within 7% cap. Amortization of transmission lines is usually 40 years and as pointed out, that is one of the problems.

Q: Page 6-57: Have gas on the north coast and don't build transmission line—that gets you a very different cost. Have you looked at those alternatives?
A: The energy is equivalent. There is more benefit to the north coast, but it is small. We were trying to do an apple-to-apple comparison, so we kept it to the north coast and as long as gas is within the 7% requirement then it is a saw-off. Gas should wash; however it shows the clean resources more broadly dispersed in the system appear to pay for transmission.

Q: There is a risk to serve with a 500 kV. You are really pushing it to get it built in time. That needs to be explicitly set out in the plan and you may lose a customer because of that.
A: Plan keeps options alive; we need to finish the negotiations.

Q: I noticed that the comparison is to the Lower Mainland, but most of the load increases are in the north –is that not factored in this analysis?
A: We almost can site gas wherever it is beneficial, then there is transmission and that is where it does get more ??value??.

Horn River Basin

Q: Right now Horn Basin is not doing anything and Fort Nelson is going to Alberta and option 1 integrates everything. Still, you have to provide generation because Alberta is not sufficient, right?
A: Option 2A is dealing with Fort Nelson on its own and maintains Alberta. Finally, Option 3 covers your last point.

Page 9-75

Q: BC Hydro is obligated to serve them electricity, right? So you aren't really doing anything here but monitoring.
A: Right, but you can specify the point supply (the point that BC Hydro has capability to supply). This is another region where the proponents and government need to get together.
A: In Fort Nelson area, there are options around Alberta, etc. and we need to develop an action plan in the long term.

Q: Right now there is no load forecast for this?
A: Correct.
Q: Fort Nelson is serviced by thermal generation on the BC side and is that counted in the 7%?
A: Right.
C: So there is a trade-off here.
C: Alberta still has a lot of coal; if you supplied Fort Nelson by gas you might be making a carbon dioxide reduction.

Site C
Page 46

Q: Is Site C's capacity contribution more critical in terms of timing?
A: We have a shortfall capacity earlier on. The reason why in Scenarios C and E, Site C doesn't have as much benefit is because it results in energy surplus in the early years. Site C is as competitive as any other resource and has more advantages in later years.

Q: If you receive your permits for Site C, can you hold off until you need it? I'm interested in finding out how long permits are valid – maintain flexibility in case events change.
A: We see a need whether LNG materializes or not. There is 7 year construction period so if not proceeding then have a fair bit of time for alternative resources. I am not sure on the legality around how long a permit is valid.

Q: There is no scenario that doesn't have any LNG?
A: Correct. We did run some scenarios/load resource balances without LNG, however we didn't do portfolios.

Q: Gap between is still needed and next available option is still very important but how it is achieved is important to know as well?
A: There are two parts to this, one is need and one is cost-effectiveness. Looking at mid-gap it is most cost effective. If we don't have LNG, then surplus energy is used by 2022 and we have energy gap by fiscal 2022. If, we were in the case of without need, then we would start to defer.

Page 9-15 and 9-16 shows the load gap

C: If you compare tables and you go to the people in the Peace you will have to tell them why you wouldn't pick that instead of Site C. It would be nice to have those numbers. The question is about the difference in cost between low growth and Site C and what is driving that and the impacts. Also note that the cost of alternatives has gone down.
A: We will have to go and talk to them about that. This is the basis for our consultation with them.

Q: My understanding is that under the reservoir there is a coal seam?
A: I am not sure of the geology but it hasn't been factored into our engineering analysis.

Contingency Resource Plans
Page 6-142 – shows uncertainties

Q: Government policy is the leading indicator of electrification -what does that mean? In that context, policy is an uncertainty, so why not in other places in the plan like in the 66% or 93%?
A: In other areas it is clear where they want to focus, but on electrification we are less clear.

Q: You don't add up uncertainties?
A: Right.

Q: What is assumption for the clean call and when will it be on line?
A: A three-year construction window and a wide-open competitive call five years ahead of time.

Q: Is the 2,000 gigawatt amount after attrition?
A: Volumes are after attrition. It is what we want delivered.

Q: Don't you think you need to launch right now?

A: We won't run a traditional process, rather we would have to look at different procurement methods – there are a host of options; we haven't landed on anything yet.
C: Between now and the next election, things are in a state of uncertainty.
C: Hard to believe that it would take five years; surely it could be shortened.
C: Might want to think about an IPP call for contingencies. The IPPs could keep permits alive and maybe pay them a bit to bring them to that stage. Low cost option and building in contingency.

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Q: Pumped storage?
A: It was in base resource plan, as a clean option, but in the contingencies we are stress testing the need for transmission lines. That was the rationale for not including it.

Q: CRP 2 and CRP 3 – there are large quantities of natural gas capacity. What does it do to the 93%?
A: This is a last resort. This is about capacity and keeping the lights on. If you had to run gas to meet the load, then we would start working on clean options to meet the 93%.

Q: Was there an assessment of probability using contingencies?
A: We don't have a probability assessment for LNG load, we treat LNG3 as a separate scenario with preparatory actions. Other two uncertainties, loads and DSM, we have assessed probability in past plans. As in past contingency plans, we plan to a net load (load less DSM) based on the expected value of the top 20th percentile. We haven't been able to unravel issue of … do you get more DSM when times are good or when times are bad?
C: Probabilities don't really make much sense here as everything goes in lock step.

Q: Interesting to see CRP 1, 2, 3—it would be useful to have a look at if you tried to meet the 93%?
A: Keep in mind that the CRPs test transmission corridors (what we'll need available on the transmission system if we can't find pumped storage or DSM). Load resource balances on CRPs are in the appendices; they show both energy and capacity load resource balances. (Refer to Appendix 9-B).
C: I thought you thought of looking at DSM as contingency. Most places around the world would look at DSM in that manner - capacity and energy.
A: Regarding capacity load shedding, we have given some thought to that but not a lot. We will see what we get out of our capacity actions with respect to DSM and we could consider it in the future.
C: The idea on contingency capacity is to meet the energy requirement of 93% - it doesn't mean you aren't trying to get 100% but rather that reality drags behind the plan. Usually contingencies are unlikely; I would be more comfortable if we said scenarios—might be semantics. I think you are right about DSM being driven by contingencies.

4. <u>Additional Questions/Topics</u>

Q: How much climate adaption is built into the plans?
A: We have looked at the large reservoirs of the Peace, Columbia and Campbell and it appears temperatures will go up slightly, and precipitation will happen at different times. The operational part of it has not been looked at. We haven't looked at run of river.
C: Storage dam capacity might be improved with more precipitation, but higher precipitation could impact a river.

Q: The First Nations are pushing for dams to be returned to their natural flows and the streams to their natural flows. I wonder if that has ever been quantified.
A: Not that I am aware of.
Q: How far off are natural flows from optimal use; that would be an interesting scenario to model?

A: There are freshets and snow melts. The electricity market today is seeing negative pricing – you wouldn't generate with it and probably would spill– it would have a pretty profound impact.

Q: Why was Williston Dam not considered for additional capacity?
A: Probably every dam could add capacity at some cost. Largely this was a cost issue.

C: There was discussion of dispatch operation protocols as part of the Columbia River Treaty and it is up for grabs now in terms of re-negotiation. You might want to have a look at that and if there are some changes in protocols, you might find more power.

5. Roundtable/Close – Facilitator

The facilitator asked the group to address several questions in the closing remarks:

- How did it go today—and since the beginning of TAC?
- What value might there be if a forum like TAC, were to continue in the future to tackle future planning questions?
- What else, if anything, do you need in order to provide written comments on the IRP by August?

Comments:

- Today went as well as it could be expected. There are aspects that I'm not happy with, but it is better than no process. There could be more value added by meeting more frequently - these are fast changing times and five years is too long an interval to have major planning events. It would be more useful with respect to our comments and feedback. We can say things BC Hydro staff cannot. TAC is well worth coming to. I'm not happy with being railroaded with a plan; so TAC is a bit of an antidote. I appreciate the patience of Hydro staff around something they can't change. I would like to see a comprehensive study on all portfolios, free of 66% and 93% for information purposes. Our feedback to the shareholders would ensure that they were better informed.

  Regarding funding for attendance, this has taken the place of a full regulatory hearing. I agree that funding should be more generous and BC Hydro should consider more funding. There are three streams for comments - public/TAC/First Nations and there are two options for comments by TAC members by August 10.

- No comments. It is a first rate plan under uncertain circumstances.

- Today was well run and I appreciated the answers. I think that feedback from stakeholders in further engagements has value.

- I appreciate the work of BC Hydro staff and receiving the very complex explanations today. It should be in front of the Utilities Commission rather than this optional planning process and I hope it's re-instated. Two years for review would be good. I support leaving stakeholders to discuss issues. Regarding funding, my group is seriously affected by not being adequately funded and the timelines for response are very compressed. It doesn't give us much time to put feedback together.

- The process is a proxy for a regulatory process; given that, we find the meetings reasonable and the sharing of information useful. It is frustrating trying to deal with things from our side and to find a meaningful place to engage. The IRP needs to move back under the jurisdiction of the Utilities Commission. I agree with the two-year review stage. However, we need different types of processes. Problems are largely the result of intrusion of government. I agree with the inadequate funding issue. Thank you; I have gleaned a lot of useful information today. An on-going mechanism is essential but the whole process could be re-engineered, including different levels of involvement and people outside of the process.

- Let me express my appreciation for the opportunity to be involved; it was useful for the commercial energy consumers' group. Well done and well run in terms of providing information; the abilities of people on the team is good and it was open and transparent. The issues are very substantial, involving big value issues for the province, customers and BC Hydro to consider. I am planning to put forward a suite of ideas in terms to improve the project and I hope you might find some of the ideas worth exploring so any kind of interaction would be important. The amount of time I spent, in preparing last set of comments was very significant. To give decent comments it is going to be a problem based on the funding available; it will be very truncated. Who do I donate my time to and for what reason? I would find continuation of the planning process valuable –it is helpful to us representing a commercial sector group to continue that. I sit on the DSM Committee and I have made the same comments around funding. Thanks to everyone.

- I am echoing some of the same comments. Thanks from Fortis BC. I agree that the plan is difficult and it is constrained by legislation, but it would be interesting if you took the constraints around gas off. I agree with continuation of TAC meetings, but every two years might be rehashing things a bit; while maybe five years is a bit long if the situation changes. I have to go back to my organization for feedback.

- So much information flows out, challenging to digest it all. Underfunding is our same issue. Kudos to Randy's (Reimann) group. Base plan as reflected is not necessarily expected plan, but more the 80th percentile. I realize you are trying to build something to keep future options open, but maybe we need to carry it a little bit further. Continuing on – absolutely great process. Five years is too long so we are not always starting from scratch. Certainly there will be things moving faster than five years and to meet on an on-going basis to deal with that would be good. I may have some questions and there should be a process to get answers back to assist in our written comments.

- The amount of work done is impressive. This is a LNG response plan. In the public sphere, it should be clearly articulated from LNG low/mid/high, with Site C/ without Site C and with clean or not. What information do I need? I see us trying to piece the picture together, so you might get an email. Absolutely support future conversation depending on funding. My other question is, who else needs to be at the table?

- Randy Reimann: Thank you. It has been a long road and we appreciate the time and effort and the whole group of very vigilant people interested in helping. It has given us a lot of guidance. We are open to questions of clarification going forward; please send those to Anne Wilson and Kenna Hoskins and we will do best efforts to answer them. This process was created under the Clean Energy Act and notwithstanding it was narrow in places; we are appreciative of your journey through this process with us. We hear you about funding and how an EPAC could be structured and funded and what the purpose could be and we will see what the next year will bring.

The Facilitator thanked everyone for their engaged participation.

6. <u>Closure</u>

The meeting ended at 5:00 p.m.