Kai Millyard Associates

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September 2, 2008

Ms Kirsten Walli
Board Secretary
Ontario Energy Board
27th floor
2300 Yonge Street
Toronto, ON
M4P 1E4

RE: EB-2007-0707 GEC-Pembina-OSEA Interrogatory Responses

Dear Ms Walli,

I enclose three hard copies of interrogatory replies to questions posed to witnesses that prepared evidence on behalf of GEC-Pembina-OSEA. Specifically,

Exhibit I, Tab 45, Schedules 1 to 4, to AEC
Exhibit I, Tab 56, Schedules 1 to 7, to Board Staff
Exhibit I, Tab 72, Schedules 1 to 6, to City of Toronto
Exhibit I, Tab 86, Schedules 1-2, to CME
Exhibit I, Tab 100, Schedules 1 to 5, to EDA
Exhibit I, Tab 113, Schedules 1 to 59, to OPA
Exhibit I, Tab 120, Schedules 1 to 2, to Pollution Probe
Exhibit I, Tab 126, Schedules 1 to 9, to PWU
Exhibit I, Tab 133, Schedules 1 to 22 and 25, to Xylene

Additional responses on Mr Torrie's evidence will be filed separately. The replies listed above have been uploaded to the Board's RESS site. A zip file containing attachments to certain Interrogatories in Excel format has been made available by email/ftp to the Board and parties. These files cannot be uploaded to the RESS site. Please take note that the ZIP file also contains a PDF attachment to IR I-100-5 which, due to a technical problem, cannot be attached to the IR reply file.

Sincerely,

Original signed by

(Mr.) Kai Millyard
Case Manager for the
Green Energy Coalition
Pembina Institute
Ontario Sustainable Energy Association

encls.
EC: All parties

Green Energy Coalition – Pembina – OSEA RESPONSE

To

Board Staff Interrogatory 1

Question:

Ref: Exhibit L-8-1, pages 10 and 11

Issue: A31

GEC-Pembina-OSEA ("GEC") states in its "Recommended Improvements in OPA Planning" that a loading order for generation dispatch should be created that begins with CDM and then adds sequentially, small scale renewables, waste heat recovery and CHP followed by large and/or remote renewables.

Does GEC know of any operating jurisdictions that have used a noneconomically based, merit order, resource dispatch system? If so, what has been the performance history of that system?

Reply:

The question appears to be based on a misreading of the evidence. The term "loading order" is intended to refer to planning and procurement priorities, not dispatch of on-line units. That said, dispatch on factors other than economics has occurred elsewhere. For example, reliability-constrained dispatch is practiced in New York City and to some extent in most electric systems, and NOx-constrained dispatch was practiced in southern California. GHG-constrained dispatch will be required in Ontario under new coal-emissions constraints.

Our reference to a planning loading order is not intended to promote uneconomical resources over economical resources. Many jurisdictions use such policies for energy planning. These were summarized by GEC in a filing before the Board in EB-2005-0523. We attach the cover letter summarizing that filing overleaf. The California example is found in that State's Energy Action Plan II and describes the loading order, or "priority sequence" of energy resources to be used to meet the State's energy needs: all cost effective energy efficiency and demand management resources first, then renewable resources, followed by distributed generation like combined heat and power, and finally clean and efficient fossil fired generation. The Plan can be viewed at http://www.energy.ca.gov/energy_action_plan/2005-09-21_EAP2_FINAL.PDF.

Witness: Jon Wallach, Paul Chernick, Richard Mazzini

David I. Poch Barrister Tel. (613) 264-0055 Fax (613) 264-2878

14 December 2005

Mr. John Zych
Board Secretary
Ontario Energy Board
2300 Yonge Street
Suite 2700
Toronto, ON

Dear Sir:

Re: EB-2005-0523 - information requested of GEC by Board Staff Counsel

Following our filing of the affidavit of Chris Neme in this case Board staff counsel contacted us asking for documentation related to three items referred to in Mr. Neme's evidence. He invited us to file information on the 'primary directives' (referred to by Mr. Neme at page 6), documentation of Docket 5720 where the Vermont PSB reduced RoE for DSM plan inadequacy (also on page 6) and to provide documentation related to the Vermont PSB's request for different efficiency investment scenarios and VEIC's response thereto (referred to by Mr. Neme at page 8).

We ask that this letter and attachments be provided to the panel.

In responding to these requests we note that 'primary directives' on energy conservation take various forms in numerous US states and accordingly we have provided a sampling:

- Many states as part of electricity restructuring included Public Benefit or System Benefit charges or funds, some of which are earmarked for energy efficiency programs thus effectively mandating a minimum spending level. Attached please find a 2004 summary of such funds assembled by the American Council for an Energy Efficient Economy (ACEEE).

- Some states mandate "least cost" approaches that require energy efficiency that is cheaper than supply to be captured. Attached are policy statements enshrined in Wisconsin and Hawaii's laws that are two such examples.

- Regulators have also directed least cost approaches. We attach a directive of the Northwest Power Planning Council that directs customers (including distributors) of Bonneville Power Administration's power who are proposing to take responsibility for DSM to develop energy efficiency plans that capture all cost effective opportunities and to address several related regulatory objectives. This is an example of a directive to distributors and as such is in a context similar to that in Ontario.

1649 Old Brooke Road, RR#2, Maberly, Ontario K0H 2B0 e-mail: poch@perth.igs.net

- Recently some states or regulators have asked utilities to exceed previous caps or targets for energy efficiency where cost effective. The Vermont PSB request of VEIC (which runs the energy efficiency utility) to provide information on more aggressive scenarios is a response of that board to Vermont's Act 61 which lifted the previous cap. Attached is VEIC's response as requested. Mr. Neme's office advises that the request from the PSB was oral. Accordingly, we provide a memo from the PSB which refers to the Board's requirement to provide a "determination of an appropriate budget level for Vermont's Energy Efficiency Utility now that the statutory cap on that funding has been removed." We also attach a copy of excerpts of Vermont law (before and after Act 61 amends it) referring to least cost planning and a requirement that regulation provide incentives for a least cost approach. The full Act 61 is available in PDF upon request.

- Another notable example of a regulator calling for efficiency investment wherever cost effective is from California. We attach the "Energy Action Plan" and the introduction and background and procedural history sections of the draft order from the CPUC to that effect. The full order can be seen at: http://www.cpuc.ca.gov/PUBLISHED/COMMENT_DECISION/48667.htm

- We also attach excerpts of 3 Vermont PSB decisions. Mr. Neme had referred to 5720 as the decision docking CVPS 75 basis points. In fact 5720 is a decision where the board warns a local utility that it could face penalties:

  > ...in keeping with our general policy, the Board will consider a failure to move forward with cost-effective efficiency programs to be sufficient cause for the Board to initiate an investigation into the rates charged by Enosburg Falls. Such an investigation could lead to orders requiring the escrow (and potential refund to customers) of revenues associated with power costs that could have been avoided by cost-effective energy efficiency investments.

  The decision where an actual reduction occurs is 5701. Also attached is an excerpt from 5270 which is the decision that sets out the primary requirement that utilities pursue cost effective DSM. The decisions are quite lengthy and we will forward electronic copies of the entire decisions to the Board. They are available to all others upon request.

I trust this information will be of assistance.

Sincerely,

David Poch

David Poch
Counsel for the GEC

cc: All parties by e-mail
George Vegh

Green Energy Coalition – Pembina – OSEA RESPONSE

To

Board Staff Interrogatory 2

Question:

Ref: Exhibit L-8-1, page 19

Issue: A34

GEC states that coal plants do not have to be maintained on-line in order to provide "insurance" for potential project delays or adverse conditions.

What is GEC's opinion regarding the feasibility of restarting a coal-fired generating station rapidly after being in cold shut down mode, and quickly providing staffing, coal supply and other services to enable the plant to be utilized for reserve conditions? Please provide examples of other organizations that have been able to carry out this endeavour.

Reply:

It is not clear what the question means by "rapid." If "rapid" refers to restart in hours, days or weeks, it is not applicable to our recommendations, which do not require any "rapid" startups in that sense.

As insurance, the coal plants would be in place to help if new capacity does not materialize as planned. That is a long-term contingency, and OPA would know many months ahead of the time that the units will actually be needed. Operators have restarted many generators from mothballed, and even nominally retired, status in periods of months. Some restarts have required new environmental retrofits, which has slowed them down; but this would not be the case here since the coal plants would not emit more in our approach (restart when needed) than in OPA's approach (operate continuously, whether needed or not).

Experience with mothballing and/or restart of steam units includes:

- Ontario Hydro

Definition of mothballing ("1991 Power Resources Report Historical and Predicted," Report 690SP, September 1991, Appendix 5)

Witness: Paul Chernick Jonathan Wallach, Richard Mazzini

A mothballed station is one in which all generating units and auxiliary systems are taken out of service and placed in protective storage for future use. Station staff complement is reduced to a level consistent with providing security of equipment, buildings and site.
Fossil-fuelled units which have been mothballed are placed in protective storage by: draining boilers and maintaining a nitrogen blanket within the pressure parts; maintaining most lubricating oil systems in service; draining and placing desiccants within heat exchangers and generators. Ongoing maintenance consists of maintaining the above conditions, turning rotating equipment at regular intervals, and maintenance of site and buildings.
The time required for recommissioning will be dependent on the length of time the unit/station has been in the mothballed state. Such factors as general deterioration, staff familiarity with equipment, and the adequacy of storage/preservation techniques will all be affected by the duration of mothballing.[1]

Emergency recommissioning implies that mothballed units will be required as soon as possible and perhaps for a short period of time. An example of this situation would be a sudden extended loss of major generating capability (e.g., several nuclear units). It is extremely difficult to predict a return to service time under this scenario because of the variables already mentioned. However, if staff were made available from other parts of the organization in adequate numbers, the first unit of a 4-unit station could return to service in approximately 16 weeks.
Remaining units would require 6 to 8 weeks each. This pre-supposes that (a) all necessary equipment, parts and supplies are in place and/or readily available, and (b) no major failures or problems are encountered during recommissioning.[2]

Hearn (coal-fired): Units 1-5 were mothballed in the early 1980s. "The last three 200 MW units at the plant resumed burning coal along with natural gas but they were phased out of operation in July 1983, due to concerns about increased air pollution in Toronto and an abundant energy supply in the province. The staff level had been reduced to around 180 when power production stopped in 1983. Some of the

[1] Note that the coal plants would be in mothballs for only a few years, so OPG should be able to avoid deterioration, maintain staff familiarity, and provide adequate storage and preservation.

[2] Note that the coal plants with be mothballed with all equipment in operating condition.

generators were operated as synchronous condensors to improve power quality until 1995… On March 16, 1990, Ontario Hydro announced the restart of two units (7 & 8) to meet demand for the winter of 1991. The restart had a projected cost of $69 million CDN. Work on the restart was well underway when the new NDP government of Premier Bob Rae cancelled the project."[3]

In the Balance of Power Demand/Supply Plan Report, Ontario Hydro's contingency plans for high load growth included demothballing 800 MW of Hearn capacity starting in 1992, with the first unit entering service in 1993 (Figure 18-2).

Ontario Hydro listed 1,167 MW of mothballed capacity at Hearn in September 1991, and projected that they would remain available as mothballed stations to 2000 ("1991 Power Resources Report Historical and Predicted," Report 690SP, September 1991, Table E-5)

Lakeview 5–8 (coal-fired) were mothballed in 1993. Ontario Hydro also analyzed mothballing of units at Lambton, Nanticoke, and Lennox from 1997 to 2007, and identified no technical obstacles. (Demand-Supply Plan hearing, Exhibit 796, December 17, 1992; pp. 13–14 and Attachment G, pp. 7 and 13)

Lennox (oil- and gas-fired: "In 1982 the station was placed in reserve due to a decrease in demand and it was subsequently reopened in 1987. Two units were again placed in reserve between 1994 and 1998." (http://www.opg.com/power/fossil/lennox.asp) All four units are currently in active service.

Other: Ontario Hydro listed as mothballed resources 256 MW of coal generation at JC Keith and 88 MW of coal generation at Thunder Bay 1 ("1991 Power Resources Report Historical and Predicted," Report 690SP, September 1991, Tables E-5 and W-5)

- New England (plants built to burn coal, converted to heavy oil)

Bridgeport 1 (85 MW, 1957): deactivated 1/1/94, returned to service in late 1996 (although it was scheduled for reactivation in 2002 as late as April 1996), and shut down again in 1998.

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[3] http://en.wikipedia.org/wiki/Hearn_Generating_Station

West Springfield 1 and 2 (102 MW, 1949 and 1952): retired in 1991, returned to service 7/1/97, retired again in 2001.

Mason 3–5 (98 MW, 1952–1955): deactivated 7/1/91, reactivated 7/1/97, retired in 2004.

- New York City

Astoria 2 (heavy oil and gas): "Consolidated Edison Company of New York, Inc. (Con Edison) operated Unit 2 of the Astoria Generating Station (Unit 2) from its commissioning in 1953 until 1993 when Con Edison removed Unit 2 from service." (NYPSC Case 00-E-0190, order of April 5, 2000) Restarted in May 2001 (NYISO Gold Book) at a cost of $15 M ("Promise and Peril in New York Power Plans." New York Times (2000 August 14), Kirk Johnson).

Hudson Avenue (heavy oil): 60-MW oil-fired plant was retired (or possibly mothballed) in 1997 (EUW 5/14/01). It was restarted in May 2001 ("2002 Load & Capacity Data," New York Independent System Operator) and retired in October 2004 ("2005 Load & Capacity Data," New York Independent System Operator).

- Constellation "will proceed with earlier plans to bring 178 MW of retired generation out of mothballs" (EUW 11/5/07)

- Entergy

Monroe 10–12 (gas; 1961, 1963, and 1968; 23 MW, 41 MW, and 74 MW) Placed in extended reserve shutdown (placed in inactive status with reduced operating staff and maintenance costs and deferred repairs) July 1, 1988. Preparation for extended shutdown included draining, disconnecting and covering equipment, and installing and operating dehumidification equipment to prevent corrosion of the units. During shutdown, Entergy conducted some inspection and maintenance activities, including maintaining the dehumidification system, inspecting stacks in 1992, installing an oil/water separator for the stormwater system in 1996, and cleaning of the diesel fuel oil tank system in 1996; and maintained relevant environmental permits In September 16, 1996, Entergy proposed restart for summer 1999. Restart was delayed by the application of the US rules regarding Prevention of Significant Deterioration (Order Partially Granting and Partially Denying Petition for Objection to Permit, Petition No. 6-99-2, Office of the Administrator, US EPA)

Other plants: Entergy was reported to have restarted 583 MW of similar mothballed capacity in early 1999 and 417 MW of capacity in June 2000 (EUW 5/29/00).

- Detroit Edison Connors Creek coal plant (240 MW) shut down for 10 years, and restarted in 1998. Its restart triggered Prevention of Significant Deterioration rules under the US Clean Air Act, leading to its conversion to gas.

- First Energy

Lake Shore Unit 18, a 245,000-kilowatt unit, placed on cold standby status in October 1993, was scheduled to resume active status in 2000 (Toledo Edison 10K 3/31/1997); actually returned in early 1999 (EUW May 10, 1999).

Burger 3, 90-MW, sat idle for more than a year before restart about 1999 (EUW May 10, 1999).

Ashtabula 'C': (coal-fired, three 44-MW boilers, 1953) "sat idle for several years before being activated by FirstEnergy in 1999" and then operated to 2003 (EUW 1/27/03).

- Taconite Harbor (225 MW coal-fired) shut down January 5, 2000 by LTV Corporation, purchased by Minnesota Power in October 2001, first unit restarted February 7, 2002 (EUW 11/26/01; Allete 2005 10-K)

- Mustang Units 1 and 2 (gas, 115 MW, Oklahoma Gas & Electric) were mothballed in the late 1980s and reactivated on July 21, 2000 after only "equipment inspections and minor repairs" (EUW August 16, 1999; OGE Energy Corp 10Q 9/30/00)

- Etiwanda Units 3 and 4 (gas, 640 MW, Reliant Energy): Mothballed 11/7/03. In June 2004, agreed with CA-ISO to bring back plant by year-end, for less than seven months lead time (EUW 7/26/04, 11/15/04)

- "TXU is prepared to 'unmothball' up to 1,600 MW of currently idled gas-fired capacity in the state if that power is needed to maintain system reliability." (EUW 3/5/07)

Green Energy Coalition – Pembina – OSEA RESPONSE

To

Board Staff Interrogatory 3

Question:

Ref: Exhibit L-8-1, pages 25 and 29
Ref: Exhibit D-5-1, Attachment 2
Issue: A7 and A8

GEC states on page 25 that it proposes that 10,000 MW (nameplate rating) of wind be included in the plan and further states on page 25 that the OPA's Ontario Wind Integration Study (Pre-filed Exhibit D-5-1, Attachment 2) would support a connection of this magnitude.

Given that the Ontario Wind Integration Study states on page 7 and 8 that:

• "beyond 5,000 MW of wind the additional load following requirement may exceed the capability of existing generators" (1.1, 3rd bullet);
• "results indicate that an increased operating reserve requirement can be expected to accommodate extreme drops in wind generation for high wind penetration scenarios (meaning 10,000 MW)" (1.1, 4th bullet); and
• "This data indicates that with large amounts of wind (meaning 10,000 MW) much more one hour ramping is required for secure operation" (1.1, 6^{th} bullet);

how does GEC come to the conclusion that the Wind Integration Study is supportive of 10,000 MW of connected wind capacity?

Reply:

This issue is described in some detail on pages 29–30 of the evidence. In addition, in Exhibit I-22-82, in response to the question:

> On D/T5/S1 P40 Line 17, OPA accepts a 5,000 MW limit on wind due to system operability issues. The limit is defined in the GE Energy study (Page 7) and is based on load following requirements. Please provide the assumptions for the planned capacity mix from which this conclusion was derived. Is it the same capacity mix as included in the IPSP?

OPA states that the analysis in Ontario Wind Integration Study "was not performed against any capacity mix…the analysis was performed using only temporally synchronized load and wind data." Hence, GE does not appear to have any basis for opining on the adequacy of the current or future Ontario generation system (under any potential plan).

From IESO hourly output data for 3Q07, Ontario's existing hydro plants demonstrated one-hour upward ramping ability totalling 4,022 MW and downward ramping of 4,339 MW; Lennox demonstrated about 1,300 MW up and down; and the various gas-fired generators showed 1,500 MW up and 1,670 MW down. Their maximum ramping rates may well be higher than those actually employed in that period. In any case, Ontario has at least 6,800 MW of ramping capability up and 7,300 MW down.

OPA shows the addition of about 4,500 MW of committed gas. Since the existing gas resources ramp about 40%–80% of their installed capacity per hour (and this seems consistent with performance of CCGT plants in the US), the committed gas resources would add about 1,800 to 3,600 MW of additional resources. Assuming the 3,000 MW of committed and planned hydro resources provide ramping proportional to the 6,000 MW of existing hydro, they would contribute another 2,000 MW, bringing total one-hour ramping to well over 10,000 MW. In addition, at times of high wind generation, Ontario is likely to be exporting energy; exports can also be ramped down as wind generation falls.

Note that first quote in the question ("beyond 5,000 MW of wind, the additional load-following requirement may exceed the capability of existing generators") indicates that GE is merely speculating and that the statement applies only to existing generation, excluding the large amount of committed gas-fired and hydro generation. The quoted bullet point goes on to assume that "wind generators will likely displace more flexible generation resources." In the Green Portfolios, wind generation displaces primarily nuclear generation, which is not flexible, so GE's speculation is not applicable.

With respect to the second quote, it is not clear how much additional 10-minute operating reserve would be required at times of high wind generation. Since high wind generation would result in the backing down of gas and hydro plants, ample operating reserves are likely to be available at those times. Many SCCTs can reach full capacity from a cold start within 10 minutes.

With respect to the third quote, the additional one-hour ramp-up requirement with 10,000 MW of wind is 3,780 MW, compared to over 10,000 MW on the system. Again, the additional ramp-up requirement is triggered by declining wind operation, which would require off-line generation to be brought on line. The capability for ramping up would generally be higher when wind generation is relatively high, since gas and hydro generation will be reduced at those times. We do not see any reason to believe that the ramping ability of the system would be inadequate when wind generation is decreasing and load is rising.

Witness: Paul Chernick, Jonathan Wallach, Richard Mazzini

Green Energy Coalition – Pembina – OSEA RESPONSE

To

Board Staff Interrogatory 4

Question:

Ref: Exhibit L-8-1, pages 85-86
Issue: A7 and A8

GEC is of the opinion that "Ontario may be able to rely on firm purchases and sales with surrounding control areas to import additional renewable power or to provide firming services for internal renewable resources" and that "Firm purchases of storage services from Manitoba and/or Quebec are more likely to be economically superior to available Ontario resources."

(a) Can GEC identify an approximate amount of potential firm purchases of renewable power and the cost of acquiring such power (both capital costs and costs to customer)?

(b) Can GEC identify the resources that would be displaced by potential firm purchases in its recommended Green Resource Portfolio and the resource portfolio recommended in the IPSP and the resulting impact on portfolio costs?

Reply:

a) Neither RII nor its clients (GEC, Pembina Institute, OSEA) are able to negotiate on behalf of Ontario with Quebec and Manitoba. OPA or some other public entity would need to pursue power contracts with Quebec and Manitoba.

b) For the Green Resource Portfolio, clean imports would replace generic green resources modeled as CCGT. It is not clear what OPA would do. With respect to costs, see (a).

Witness: Paul Chernick, Jonathan Wallach, Richard Mazzini

Green Energy Coalition – Pembina – OSEA RESPONSE

To

Board Staff Interrogatory 5

Question:

Ref: Exhibit L-8-3, page 12 line 1 and page 58 line 1
Issue: A2, A3, A4, A5 and A34

Mr. Parker advises the OEB to direct the OPA to resubmit a resource plan that is based on meeting lower future loads. He reaches this conclusion on the basis of aggregate contributions of energy conservation. He notes on page 58 that the required levels of funding to bring about such load reductions are “difficult to answer without performing comprehensive and detailed modelling”.

(a) Does Mr. Parker recommend that the OPA carry out such comprehensive modelling? If so, is he able to provide guidance based on Vermont’s experience as to how this should be done?

(b) Would he specifically recommend estimating Levelized Unit Energy Costs (LUECs) for each type of energy conservation (suitably categorized) and then developing a strategy based on carrying out the least-cost opportunities first?

(c) How can the Board be confident that planning for lower supply capacity will not result in security and reliability issues?

Reply:

a) I recommend that OPA target a savings level from all CDM activity of 2.5% per year of system sales. I recommend that OPA be required to propose, perhaps on a three to five year cycle, plans for annual savings targets and the budgets to support them. This will provide an opportunity to assess implementation effectiveness, what measures and strategies to promote, and what level of spending will be required. VEIC could provide guidance in designing such a budget and planning process but the matter is not amenable to a simple response here.

b) I would recommend that the savings be projected based on a consideration of the costs for all types of energy savings. LUECs are often useful but can obscure important differences in resource attributes. I do not support the concept of buying efficiency "measure-by-measure" based on where each lies on a cost curve. I support seeking all cost-effective efficiency and CDM acquisition through an approach that promotes comprehensiveness, lowers transaction costs, and builds infrastructure, and trust relationships with market partners and customers over time.

c) All supply planning involves risk, and forecasts into an uncertain future. Although it is a more familiar thing to build new supply and generation, it is clear that the risks of such generation may actually be higher than the risks of investing aggressively in CDM. Efficiency and most renewable energy have short lead times, small incremental size, low or no fuel costs, and little environmental risk. The substantial avoidance of these risks could well make a CDM-heavy portfolio far more resilient than one with that relied heavily on vast capital investment in single facilities.

Green Energy Coalition – Pembina – OSEA RESPONSE

To

Board Staff Interrogatory 6

Question:

Issue: A31

Reference: Exhibit L-8-9

Mr. Gibson, the principal author of Exhibit L-8-9, "An Analysis of the Ontario Power Authority's Consideration of Environmental Sustainability in Electricity System Planning" ("Analysis"), was a key member of the OPA's Sustainability Advisory Group ("Group"). According to the OPA's prefiled evidence, the Group "provided advice on the development of the sustainability framework; the application of basic sustainability principles, the appropriateness of the context-specific criteria; the assessment of environmental performance of the Plan; advice and comment on the Preliminary Plan; and a review of the stakeholder consultation process".

The Analysis identifies and explains a number of deficiencies in the OPA's implementation of sustainability requirements in developing the proposed plan. For example, it criticizes the OPA for a lack of an explicit commitment "to ensure that the Preliminary Plan's objective would contribute positively to sustainability"; and "the OPA's context-specific criteria are not comprehensive enough…".

What was the Group's recommendation to the OPA regarding sustainability matters as they relate to the IPSP?

Reply:

The Sustainability Advisory Group as a whole was not asked to undertake a collective analysis or to develop and provide mutually accepted recommendations on any of the matters listed in the quotation from the OPA's prefiled evidence. There were no Group recommendations to the OPA.

Individual members offered comments on various matters at the meetings, and some, at least, engaged in additional exchanges with Dr. Neil Freeman, who was the OPA's lead contact with the Group.

Witness: Robert Gibson, Mark Winfield

The Group met with OPA officials and consultants twice – on 27 October 2006 and 20 December 2006. The meetings were devoted to presentation of environmental impact assessment work by OPA consultants as well as discussion of topics more broadly relevant to sustainability issues in the IPSP. While the discussion included attention to or at least mention of aspects of each of the topics listed above, there was no time for or attempt to initiate a careful review of any of these many complex items. Moreover the discussions with the Group came far too late in the planning process to influence the framework, principles and criteria that actually influenced the development of the IPSP, which was initiated and largely completed before the Group was established. The key issues at the time of the Group's meetings with the OPA turned on how to present the results of the planning work that had already been done.

Correspondence between Dr. Gibson and Dr. Freeman on this matter of retroactive application of a sustainability framework can be provided to the OEB if that would be appropriate and potentially helpful.

Witness: Robert Gibson, Mark Winfield

Green Energy Coalition – Pembina – OSEA RESPONSE

To

Board Staff Interrogatory 7

Question:

Issue: A31

Reference: Exhibit L-8-9

The Analysis filed as Exhibit L-8-9 states, "In the areas of significant conflict between the proposed IPSP and the likely conclusions of planning flowing from sustainability-based evaluation, including the plan's nuclear components and low-efficiency applications of natural gas, the OEB would be justified in requiring the OPA to reconsider these options in light of comprehensive, properly specified and carefully applied sustainability criteria and trade-off rules, and to submit a suitably revised IPSP for the next triennial review."

Please elaborate on this proposal of the Analysis and clarify if GEC/Pembina/OSEA would support Board's approval of the current IPSP.

Reply:

The interrogatory seeks an indication of the GEC-Pembina-OSEA position as opposed to the authors' advice. GEC-Pembina-OSEA have indicated that they will likely submit that the IPSP as submitted not be approved or be approved if OPA accepts certain amendments or conditions (see response to CME IR I-86-1). We understand that GEC-Pembina-OSEA will indicate its full position in final argument.

Our analysis as reported in Exhibit L-8-9 indicates that the requirement for ensuring meaningful consideration of environmental sustainability in the development of the IPSP was not met. The evident implication is that the current IPSP is not in compliance with the IPSP regulation, and therefore cannot be approved by the board.

Our analysis also indicates, however, that due consideration of sustainability requirements would favour an integrated power system plan and portfolio that includes and expands some components of the current IPSP proposal. In light of the need to move forward with the renewal of Ontario's electricity system, those aspects of the IPSP that are evidently compatible with sustainability objectives, including the plan's CDM and low-impact renewable energy components and the phase out of coal-fired generation, could be accepted with enhancements to

- pursuing the province's full achievable cost effective CDM potential identified in the evidence of Parker and VEIC (EB-2007-0707 Exhibit L Tab 8 Schedule 3), and Chernick, Wallach, Mazzini and Resource Insight Inc. (EB-2007-0707 Exhibit L Tab 8 Schedule 1);
- increasing reliance on renewable supply resources as identified in the evidence of Scheer (EB-2007-0707 Exhibit L Tab 8 Schedule 6), Hennessy (EB-2007-0707 Exhibit L Tab 8 Schedule 8) and Chernick, Wallach, Mazzini and Resource Insight Inc. (EB-2007-0707 Exhibit L Tab 8 Schedule 1); and
- increasing the role of recycled energy and combined heat and power as per the evidence of Casten (EB-2007-0707 Exhibit LTab 8 Schedule 7) And
- accelerate the phase-out of coal fired generation.

Finally, our analysis indicates significant conflict between some components of the proposed IPSP and the likely conclusions of planning flowing from sustainability-based evaluation. The most significant of these areas of conflict are the plan's nuclear components and low-efficiency applications of natural gas. The OEB would be justified in requiring the OPA to reconsider these options and alternatives to them in light of comprehensive, properly specified and carefully applied sustainability criteria and trade-off rules, and to submit a suitably revised IPSP for the next triennial review.

In sum, our analysis would support a decision by the Board to offer an approval of an altered version of the IPSP (or provide a conditioned approval) that, in the ways outlined above, would be more consistent with due consideration of sustainability requirements.