SUBJECT:

REFERENCE: MIPUG Report Page 3-9 Appendix B page B-3

PREAMBLE:

Intergroup states "Proceeding to Opportunity-Based visions should not excessively impinge on those parties focused only on the shorter horizon solely in order to benefit the longer-term. A common standard for new bulk power projects such as hydraulic generation is that adverse impacts on financials or rates from new developments should not exceed somewhere in the order of 3-7 years until the “cross-over” point of costs into benefits is reached, and should not be excessively costly during the time frame up to the cross-over.

Intergroup further states “Hydro’s economic analysis reflects values over 78 years, while the financial analysis terminates at 50 years.

For many ratepayers, analysis that terminates at a different horizon (e.g., only reflect the impacts of the scenario over the first 20 or 30 years) may be valuable.

QUESTION:

a) Please indicate whether a 78 year time horizon is appropriate for evaluation of the Preferred Plan and Alternatives and if not what alternative time frame should be used?

ANSWER:

(a)

In Mr. Bowman’s view, when doing project analysis on a long-lived project, it is important to use a range that reasonably captures the lifetime benefits of the project. For this reason, an analysis horizon somewhere on the order of 78 years, as used by Hydro (including values that go beyond 78 years, as part of the “salvage value”) is appropriate for NFAT economic analysis. This is a horizon that suitably captures the long-term benefits of major hydraulic development. This analysis can help to indicate whether a project is generally in the long-term interests of ratepayers or Manitobans.

In support of this concept, Mr Bowman notes that La Capra Associates produced Figure 9-15[1] which is helpful in understanding the horizon required to capture the benefits of long-lived hydro developments. Figure 9-15, reproduced below, illustrates Plan 4 (K19/Gas/250MW), Plan 5 (K19/Gas/250MW with WPS Sale & Inv.), Plan 6 (K19/Gas/750MW), and Plan 14 (PDP) in relation to Plan 1 (All Gas) which is represented by the horizontal axis. The Figure serves to illustrate that by using an economic model which includes as "costs" the cash spent on constructing the capital project, the timeframe for looking at benefits must be sufficiently long to receive the full lifetime benefits of the costs incurred.

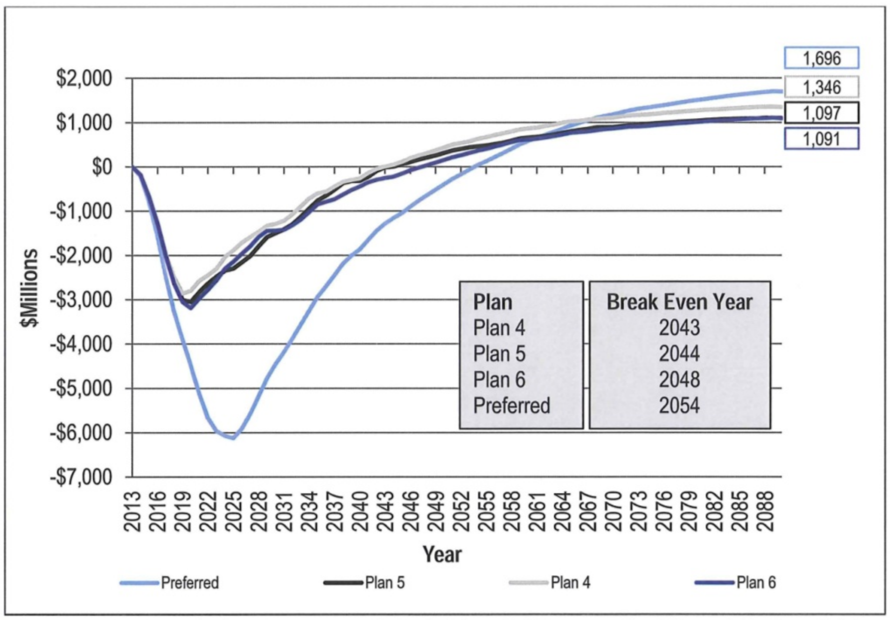


Figure 9-15: Cumulative Incremental Cash Flow Difference for Plans 4, 5, 6, and 14 as Compared to the All Gas Case – Millions of 2014 Present Value Dollars

Mr. Bowman has also noted that for assessing ratepayer impacts, the considerations are somewhat different. It is important to look at both long-term and shorter-term timeframes as a complement to the long-term economic analysis. It is entirely possible that a project that has good long-term economics may have a significant adverse impact on ratepayers over the short or medium term (e.g., in this context, may cover from 5 - 30 years), which is the case with the PDP. In this situation, it may be that the project parameters can be revised by:

- Looking at alternative financing arrangements; or

[1] La Capra Associates Inc., Technical Appendix 9A: Economic Analysis Part I, page 9A-37 (January 24, 2014).

- The Government could take on a different role to enable the project to proceed[2].

If project parameters cannot be altered to balance the significant impacts in the short- to medium- term than the project cannot be supported, notwithstanding a good long-term economic profile.

[2] See PUB/MIPUG I-11.

SUBJECT:

REFERENCE: MIPUG Report Page 3-10

PREAMBLE:

Intergroup speaks to the complimentary risks that higher rates may be met more easily met because of better economic conditions on a macro-economic level.

QUESTION:

a) Please explain and elaborate how rate increases proposed under adverse scenarios of higher costs of construction in Northern Manitoba driven by global demand for resources and higher borrowing costs for Manitoba Hydro and ratepayers are complimentary for ratepayers ability to absorb rate increases that exceed inflation.

b) Please elaborate on what is meant by slightly higher rates.

ANSWER:

(a)

One aspect of the assessment of risk exposure, when looking more broadly for how risks occur at a population level, is the extent to which risks of an outcome either have the tendency to exacerbate the risk event, or to mitigate it (i.e., have more of an insurance nature)[1]. The classic example in economic theory is an individual who both works for a given company, plus owns stock in that company. The stock investment may not be particularly risky for a general investor, but for this individual it exacerbates the risks they already face by working for the company – in difficult times there is an exposure to the share price dropping at the same time employment is terminated.

The premise for the statement quoted from Mr. Bowman's evidence is one part of the assessment as to whether the risks associated with the PDP tend to be exacerbating factors or complementary factors to other risks to the Manitoba economy. Those factors that are complementary are likely of somewhat less need for in-depth assessment than those that are exacerbating factors.

[1] This is discussed further, in relation to discount rates, in MH/MIPUG I-9

- In the case, for example, of low interest rates, such conditions tend to arise when general economic conditions are worse than average (i.e. recessions, few investment opportunities for capital, little market growth). These conditions would likely be somewhat more challenging than average for Manitoba households and businesses; however, the economics of hydro development are at their best. In short, the two conditions are complementary and for this reason Mr. Bowman did not focus extensively on the interest rate risks in Appendix C.

- In contrast, the risks posed by low gas prices are a major exacerbating factor, particularly for Manitoba exporting and energy-intensive businesses. These businesses would be facing upward cost pressures in Manitoba while their competitors in other jurisdictions would be securing cost benefits. For this reason, low gas prices/export prices is an exacerbating factor, and is part of the basis for Mr. Bowman's decision to carefully model this situation in Appendix C, Figures 21 and 22[2].

(b)

Mr. Bowman's quote is indicating that if there are offsetting features in the economy that can help complement some degree of electricity price pressures, then a slightly higher rate burden could in theory be acceptable. In this context, the slightly higher rate burden may be consistent with 0.1%/year higher rate increases than under the best alternative (Plan 1 (All Gas)), to perhaps as high as 0.2%/year.

Looking to Appendix 11.4, the sustained rate impacts of each modeled plan over the period to 2031 are shown for each of the 27 sensitivity scenarios. These are summarized in Figure 1 below. The difference compared to Plan 1 (All Gas) is provided in Figure 2. To summarize the key aspects with respect to Plan 4 (K19/Gas/250MW) and Plan 1 (All Gas):

- Plan 4 (K19/Gas/250MW) versus Plan 1 (All Gas) indicates that REF-REF-REF conditions have almost identical rate impacts (3.43%/year versus 3.42%/year, or a 0.01%/year rate improvement for Plan 4 (K19/Gas/250MW) versus Plan 1 (All Gas)). Varying one of capital cost or interest rates shows rate impacts in this "slight" range:

[2] Found on pages C-31 and C-32.

- **Capital costs** variability shows a rate improvement of 0.08%/year for low capital costs, and a rate disadvantage of 0.12%/year for high capital costs.

- **Interest rate** variability shows a range of 0.16%/year rate improvement for low interest rates, and a 0.10%/year rate disadvantage for high interest rates.

- **Capital costs and interest rates compounded effects** only lead to a range of 0.25%/year disadvantage (high interest rates/high capital costs) and a 0.23% rate improvement (low interest rates/low capital costs)

For Plan 4 (K19/Gas/250MW) versus Plan 1 (All Gas), export price variability drives rate impacts outside this range)

- **Export prices alone** show variability from a rate improvement of 0.22%/year for high energy prices (REF-HIGH-REF scenario), and a rate disadvantage of 0.21%/year for low energy prices (REF-LOW-REF scenario).

- **Export price compounded effects** show a variability from 0.46%/year rate advantage (LOW-HIGH-LOW scenario) to a 0.43%/year rate disadvantage (HIGH-LOW-HIGH scenario) in the most extreme scenarios of the 27 reviewed.

This is an additional reason why low export price scenarios were assessed in Mr. Bowman's evidence Appendix C, over the other variables.

Figure 1: Levelized Annual Rate Impacts to 2031, per Appendix 11.4

Economic Conditions	Energy Prices	Capital Costs	Plan 1 (All Gas)	Plan 7 (SCGT/C26)	Plan 2 (K22/Gas)	Plan 4 (K19/Gas/250 MW)	Plan 13 (K19/C25/250 MW)	Plan 6 (K19/Gas/750 MW)	Plan 12 (K19/C31/750 MW)	Plan 14 (PDP)
Ref	Ref	Ref	3.43%	3.86%	3.49%	3.42%	3.98%	3.50%	3.80%	3.95%
Ref	Ref	High	3.50%	4.00%	3.64%	3.62%	4.27%	3.71%	4.05%	4.27%
Ref	Ref	Low	3.37%	3.74%	3.39%	3.29%	3.76%	3.36%	3.63%	3.72%
Ref	High	Ref	3.17%	3.41%	3.05%	2.95%	3.33%	3.00%	3.32%	3.37%
Ref	High	High	3.25%	3.56%	3.20%	3.16%	3.64%	3.22%	3.57%	3.70%
Ref	High	Low	3.11%	3.29%	2.94%	2.81%	3.09%	2.85%	3.12%	3.11%
Ref	Low	Ref	3.72%	4.31%	3.95%	3.93%	4.65%	4.04%	4.34%	4.58%
Ref	Low	High	3.79%	4.45%	4.10%	4.13%	4.92%	4.25%	4.58%	4.88%
Ref	Low	Low	3.67%	4.20%	3.87%	3.80%	4.44%	3.91%	4.17%	4.36%
High	Ref	Ref	4.49%	5.03%	4.58%	4.59%	5.31%	4.67%	4.98%	5.28%
High	Ref	High	4.57%	5.20%	4.75%	4.82%	5.64%	4.92%	5.27%	5.64%
High	Ref	Low	4.44%	4.91%	4.49%	4.44%	5.07%	4.52%	4.79%	5.01%
High	High	Ref	4.19%	4.53%	4.09%	4.07%	4.61%	4.12%	4.44%	4.66%
High	High	High	4.27%	4.71%	4.27%	4.29%	4.95%	4.36%	4.73%	5.02%
High	High	Low	4.13%	4.40%	3.98%	3.91%	4.35%	3.95%	4.24%	4.36%
High	Low	Ref	4.83%	5.54%	5.08%	5.13%	6.01%	5.25%	5.56%	5.94%
High	Low	High	4.91%	5.70%	5.24%	5.34%	6.32%	5.48%	5.82%	6.28%
High	Low	Low	4.78%	5.42%	4.99%	4.99%	5.78%	5.11%	5.37%	5.69%
Low	Ref	Ref	2.40%	2.67%	2.31%	2.24%	2.58%	2.31%	2.60%	2.55%
Low	Ref	High	2.47%	2.79%	2.43%	2.41%	2.82%	2.49%	2.81%	2.81%
Low	Ref	Low	2.34%	2.57%	2.21%	2.11%	2.38%	2.17%	2.43%	2.33%
Low	High	Ref	2.17%	2.25%	1.89%	1.79%	1.93%	1.83%	2.13%	1.96%
Low	High	High	2.24%	2.38%	2.03%	1.97%	2.19%	2.03%	2.36%	2.25%
Low	High	Low	2.11%	2.14%	1.79%	1.65%	1.72%	1.69%	1.95%	1.73%
Low	Low	Ref	2.66%	3.10%	2.74%	2.71%	3.22%	2.81%	3.09%	3.15%
Low	Low	High	2.72%	3.22%	2.86%	2.88%	3.45%	2.99%	3.30%	3.41%
Low	Low	Low	2.60%	3.00%	2.65%	2.58%	3.03%	2.68%	2.93%	2.95%

Figure 2: Levelized Annual Rate Impacts – Difference from Plan 1 (Positive Values represent Higher Rate Impacts)

Economic Conditions	Energy Prices	Capital Costs	Plan 1 (All Gas)	Plan 7 (SCGT/C26)	Plan 2 (K22/Gas)	Plan 4 (K19/Gas/250 MW)	Plan 13 (K19/C25/250 MW)	Plan 6 (K19/Gas/750 MW)	Plan 12 (K19/C31/750 MW)	Plan 14 (PDP)
Ref	Ref	Ref	*0.00%*	0.43%	0.06%	(0.01%)	0.55%	0.07%	0.37%	0.52%
Ref	Ref	High	*0.00%*	0.50%	0.14%	0.12%	0.77%	0.21%	0.55%	0.77%
Ref	Ref	Low	*0.00%*	0.37%	0.02%	(0.08%)	0.39%	(0.01%)	0.26%	0.35%
Ref	High	Ref	*0.00%*	0.24%	(0.12%)	(0.22%)	0.16%	(0.17%)	0.15%	0.20%
Ref	High	High	*0.00%*	0.31%	(0.05%)	(0.09%)	0.39%	(0.03%)	0.32%	0.45%
Ref	High	Low	*0.00%*	0.18%	(0.17%)	(0.30%)	(0.02%)	(0.26%)	0.01%	0.00%
Ref	Low	Ref	*0.00%*	0.59%	0.23%	0.21%	0.93%	0.32%	0.62%	0.86%
Ref	Low	High	*0.00%*	0.66%	0.31%	0.34%	1.13%	0.46%	0.79%	1.09%
Ref	Low	Low	*0.00%*	0.53%	0.20%	0.13%	0.77%	0.24%	0.50%	0.69%
High	Ref	Ref	*0.00%*	0.54%	0.09%	0.10%	0.82%	0.18%	0.49%	0.79%
High	Ref	High	*0.00%*	0.63%	0.18%	0.25%	1.07%	0.35%	0.70%	1.07%
High	Ref	Low	*0.00%*	0.47%	0.05%	0.00%	0.63%	0.08%	0.35%	0.57%
High	High	Ref	*0.00%*	0.34%	(0.10%)	(0.12%)	0.42%	(0.07%)	0.25%	0.47%
High	High	High	*0.00%*	0.44%	0.00%	0.02%	0.68%	0.09%	0.46%	0.75%
High	High	Low	*0.00%*	0.27%	(0.15%)	(0.22%)	0.22%	(0.18%)	0.11%	0.23%
High	Low	Ref	*0.00%*	0.71%	0.25%	0.30%	1.18%	0.42%	0.73%	1.11%
High	Low	High	*0.00%*	0.79%	0.33%	0.43%	1.41%	0.57%	0.91%	1.37%
High	Low	Low	*0.00%*	0.64%	0.21%	0.21%	1.00%	0.33%	0.59%	0.91%
Low	Ref	Ref	*0.00%*	0.27%	(0.09%)	(0.16%)	0.18%	(0.09%)	0.20%	0.15%
Low	Ref	High	*0.00%*	0.32%	(0.04%)	(0.06%)	0.35%	0.02%	0.34%	0.34%
Low	Ref	Low	*0.00%*	0.23%	(0.13%)	(0.23%)	0.04%	(0.17%)	0.09%	(0.01%)
Low	High	Ref	*0.00%*	0.08%	(0.28%)	(0.38%)	(0.24%)	(0.34%)	(0.04%)	(0.21%)
Low	High	High	*0.00%*	0.14%	(0.21%)	(0.27%)	(0.05%)	(0.21%)	0.12%	0.01%
Low	High	Low	*0.00%*	0.03%	(0.32%)	(0.46%)	(0.39%)	(0.42%)	(0.16%)	(0.38%)
Low	Low	Ref	*0.00%*	0.44%	0.08%	0.05%	0.56%	0.15%	0.43%	0.49%
Low	Low	High	*0.00%*	0.50%	0.14%	0.16%	0.73%	0.27%	0.58%	0.69%
Low	Low	Low	*0.00%*	0.40%	0.05%	(0.02%)	0.43%	0.08%	0.33%	0.35%

SUBJECT:

REFERENCE: MIPUG Report Page 3-12

PREAMBLE:

Intergroup states there is 1-2 potential loads and likely more that could credibly require power from Manitoba Hydro over this period which are not yet contained within the load forecast.

QUESTION:

a) Please elaborate on what Intergroup believes are not included in the current load forecast.

b) Please elaborate on how Plan 1 could be altered to meet additional load growth and the directional implications on the analysis provided.

ANSWER:

(a)

Given the approach adopted by Manitoba Hydro with respect to Potential Large Industrial Load (PLIL), Mr. Bowman is not aware of any omissions to the current load forecast.

However, Mr. Bowman notes that the PLIL forecast is not simply hypothetical, and there are risks that it could be low. Two examples are provided in the response to MH/MIPUG I-4; specifically,

- The Vale 1-D Project: http://www.cbc.ca/news/canada/manitoba/thompson-s-future-looks-up-as-vale-studies-mine-potential-1.2437647
- TransCanada's Energy East Pipeline: http://www.energyeastpipeline.com/

The potential for load increases also includes possible further development of energy intensive industries such as Information Technology, as noted in the following:

- An Article in the Winnipeg Free Press, 'IT Operations Drawn to City' on January 17, 2014: http://www.winnipegfreepress.com/business/it-operations-drawn-to-city-240708581.html

- A Blog post by Yes! Winnipeg, 'Yes! Winnipeg on track to create, retain 4,200 jobs by end of 2015' on January 2, 2014: http://yeswinnipeg.economicdevelopmentwinnipeg.com/blog/can_they_do_it_yes_they_can/

Mr. Bowman's comments reflect a concern that there is significant discussion in the NFAT proceeding about risks that the current load forecast could be too high. While this is possible, there are equally contributing factors that could readily result in the load forecast being too low.

(b)

Plan 1 (All Gas) is characterized by resource additions as needed to meet energy and/or capacity deficits (CCGT or SCGT as appropriate). For the 2012 base case, units are added in 2022, 2025, 2028 (all SCGT), 2031 (CCGT), 2034 (SCGT), 2037, 2040, 2044 (all CCGT), and 2047 (LM6000)[1]. For this reason, it is possible to simply add units more frequently if domestic load were to grow faster than expected. The added units would increase the costs of Plan 1 (All Gas). It would likely not have an effect to the same extent on the capital investment under Plan 14 (PDP). Also note that following 2031, the quantity of thermal generation under Plan 1 (All Gas) increases notably so the cost effects of increased load also relate to thermal generation, not just capital.

[1] NFAT Business Case, Chapter 8: Determination and Description of Development Plans, page 20 of 22 (August, 2013). Note that following 2047 replacement capital costs are the only resource additions forecast, as no additional growth in energy or peak load requirements is estimated beyond 2047.

SUBJECT:

REFERENCE: **MIPUG Report Page 4-1**

PREAMBLE:

Intergroup states: "though this value appears large, the financial analysis in Chapter 11 of Hydro's NFAT Business case indicates that revenue requirement impacts to amortize the planning costs already incurred (sunk costs) are a significant factor in neutralizing the differences between Plans 1 (All Gas) and 14 (PDP) as: (a) under Plan 1 (All Gas), these costs are amortized into rates at a faster pace, while (b) under Plan 14 (PDP) these project costs are amortized into rates over the full project life as part of depreciation expense once the resource comes in-service. These sunk costs are responsible for $1.6 billion in costs charged to ratepayers under Plan 1 (All Gas).

QUESTION:

a) Please indicate whether or not the treatment of sunk costs on ratepayer impacts for comparative plans distorts the analysis.

b) Please comment on how the comparative analysis would be impacted if sunk costs were amortized over a longer period for rate setting purposes.

ANSWER:

(a) and (b)

No, given the reality of the sunk costs, the treatment of sunk costs is not distorting the analysis, as these costs are real, and must be addressed. It does not appear they are misrepresented or excessively loaded on the cost analysis of any scenario.

A longer amortization period may reduce the rate impacts somewhat; however the current assumption used by Hydro in the financial analysis is equivalent to a nearly 20 year amortization. In regard to longer amortization:

1) The approach would be unusual. Mr. Bowman is only aware of one similar regulatory account which has used a longer amortization (Newfoundland Hydro is amortizing a $96 million 1997 foreign exchange loss on Swiss Franc and Japanese Yen over approximately 50 years).

2) The benefits may be relatively small, as a lower annual amortization would be offset by a higher annual interest expense associated with deferring the collection of the amounts. Once the horizon extends nearly 20 years, benefits from further deferral can become quite small.

Despite the above, it is also important to note that the scale of sunk costs is very large, and the treatment of these costs does serve to improve the economics of Keeyask considerably, in two ways:

1) The economic analysis is comparing the net costs of Keeyask to alternatives. Given approximately 19% of Keeyask's total capital costs ($1.2 billion[1] of approximately $6.2 billion) have been spent to June 2014, the Keeyask project overall has a significant leg up on other alternatives. This would not have been the case had the NFAT assessment been able to occur, for example, a number of years ago when the sunk costs of Keeyask were far smaller.

2) The financial analysis is comparing the costs of building Keeyask [e.g., Plan 4 (K19/Gas/250MW)] against the costs of amortizing Keeyask planning costs [e.g., Plan 1 (All Gas)]. While the sunk costs of Keeyask are amortized in the plans that build Keeyask, they are amortized over the entire life of the project, which is much longer than the 20 years over which plans that do not build Keeyask amortize these same costs. The net effect is that customers pay the same rates under these two plans (under REF-REF-REF conditions) for the first 20 years (2032), and at the end either own a system with gas plants, or a system with Keeyask, built at 2019 capital cost[2] and with substantial additional equity. This is the reason Plan 4 (K19/Gas/250MW) is so attractive in the NFAT analysis. If it had been possible that the NFAT proceeding could have occurred, with all the same information, at a time when there was still a lower investment in Keeyask, then the project would not have appeared as attractive when compared to Plan 1 (All Gas).

[1] MIPUG/MH I-3(c)
[2] As opposed to being constructed at a later date with more inflation occurring prior to the construction.

SUBJECT:

REFERENCE: MIPUG Report Appendix B Page B-8

PREAMBLE:

Intergroup states Chapter 10 includes a flawed methodology that requires caution with model outputs, and which results in many of the Hydro Tables and Figures being incorrect.

QUESTION:

a) Please confirm that the low interest rate / low discount rate impacts of the "All Gas" plan impacts the NPV because the future cost of generation with natural gas has a greater impact than with a higher discount rate.

b) Please identify which of the tables and figures are incorrect and the implications on the analysis provided.

ANSWER:

(a)

Yes. A low discount rate impacts the NPV because the future cost of generation with natural gas has a greater NPV value with a low discount rate than it does with a high discount rate. This, however, is an entirely expected and appropriate outcome so long as the output data is used correctly.

The problematic part only arises when scenarios from one plan (e.g., Plan 1 (All Gas)) are compared to other Plans using a different discount rate.

In Mr. Bowman's evidence, three different approaches or solutions are provided that can address this issue:

1. Rely solely on comparing values from each plan that are related to Plan 1 (All Gas) under the same scenario;
2. Convert capital costs of projects to a form of levelized Unit Energy Costs (UECs); or

3. Move the focus to the Financial Analysis (Chapter 11) and use the values presented there for discounting and NPVs[1].

Of note, La Capra Associates identifies effectively the same issue and effectively elects to use approach #1 above. La Capra explains the issue as follows:

> In the MH PAQ, in the last column the 9th row down is the scenario of Low Energy Prices, Low Discount Rates and Lows Capital Costs. The value of the cell is -$2,155 or approximately $2.2 billion of an NPV penalty. This -$2,155 value in words is that the Preferred Development Plan under the future scenario of Low/Low/Low outcomes is $2.155 billion higher in costs than the All Gas Plan under the Reference/Reference/Reference scenario. This does not tell us whether MH would be better off under Low /Low /Low scenario conditions with the All Gas Plan or the Preferred Development Plan[2].

As a result, to avoid this misinterpretation of data, LCA compares case results of each plan to the Plan 1 (All Gas) base case under the same scenario. La Capra however takes this approach farther than proposed by Mr. Bowman to effectively generate S-curves with vertical lines for Plan 1 (All Gas). La Capra's S-curve analysis is accurate, although one must be careful about the interpretation of the vertical line for Plan 1 (All Gas). This is not to be interpreted as an indication that Plan 1 (All Gas) has no risk. Also note that La Capra's work does not end at this step, but also considers the financial modelling (Mr. Bowman's alternative solution #3), therefore, the La Capra Approach read in its entirety is a reasonable risk analysis.

(b)

Mr. Bowman outlines the appropriate versus the inappropriate uses of Hydro's economic data in Appendix B to the pre-filed testimony.

In summary, all tables that show "S-curves", box-and-whisker plots and economic P10/P90 values for each plan are problematic in Hydro's NFAT Business Case.

In Chapter 10 of the NFAT, Hydro presents a probabilistic analysis to capture the range of uncertainty with 27 scenarios (Low, Reference, and High scenarios for each of the three variables deemed to be the highest impact factors, energy prices, economic

[1] Appendix B: Economic Analysis Critique, Section 4.0: Approaches to Address Issues, pages B-10 to B-12.
[2] Noted in La Capra Associates Inc., Technical Appendix 9A, page 9A-60 and 9A-61, January 24, 2014 Public Version

conditions and capital costs and the associated permutations). The values for each scenario, for each Plan, are presented in a "quilt" (e.g., NFAT Chapter 10 Table 10.4). Of the 27 scenarios presented by Hydro, each scenario is acceptable and correct when compared across ***the same row*** of the "quilt", answering the question "if a given set of future conditions arise, which plans are better/worse than Plan 1 (All Gas).

Further, use of the quilt is appropriate for comparing across *different rows* of the quilt, so long as the scenarios being compared do not vary the interest rate/discount rate. It is only the scenarios that vary the interest rate/discount rate that should not be compared across different rows. This is because the economic analysis includes more than just the incremental costs of each plan[3]. The S-curves, box-and-whisker plots and P10/P90 values are all fundamentally based on comparing across all rows, and as such as affected by this flawed approach.

The end result of Hydro's approach is that it has a tendency to make gas look more risky than reality, and make plans that have early investment in major capital works look less risky.

[3] As can be seen in the Economic Summary Tables at the end of Appendix 9.3 for each Plan Scenario, Fixed O&M, Capital Taxes, Gross Revenue, Water Rentals, Thermal Burn and Power Purchases are for the entire Hydro system, including new and existing operations. Varying the discount rate used to present value these figures for comparison of plans provides misrepresentation of data, by weighting the existing system by different amounts in the comparison.

SUBJECT:

REFERENCE: MIPUG Report Appendix C Page C-3, C-4

PREAMBLE:

Intergroup states "The value of 1.86% real would qualify as a low discount rate for sensitivity analysis and is comparable to discount rates applied in cases of extremely long horizon impacts."

Intergroup further states: There is no basis to suggest that 1.86% real represents a reasonable customer perspective on the time preference for returns to their investments through rates (pay higher rates today to get lower rates in future) much less that such a rate could be applied assuming there is no need to further consider risks to customer. Customers clearly face risks with respect to their "investment" via higher Hydro rates, both from the possibility that the benefits in future will not arise, as well as such practical matters as whether the customer may, for example, move away from Manitoba and never see any return on the higher rates they pay in the near-term.

QUESTION:

a) Please indicate what projects have applied a discount rate of this nature and discuss the merits of applying such a discount rate for sensitivity analysis purposes.

b) Please indicate what discount rate Intergroup believes should be applied to reflect ratepayers interests in the Preferred Development Plan and options and discuss if and how risk should be reflected in the discount rate.

ANSWER:

(a)

Mr. Bowman is not aware of any hydroelectric or similar projects *per se* (e.g., an NFAT type proceeding) that applied a 1.86% real discount rate. Mr. Bowman is aware of analyses conducted in the energy and environmental fields for other purposes that have used a low discount rate of this nature. Two of these are highlighted below:

In its review of the costs associated with cancelling the Oakville power plants in Ontario, the Auditor General of Ontario used a nominal discount rate of 4%, which would be approximately similar to the real rate of 1.86% (at 2% inflation, the 4% nominal rate would equal 1.96% real)[1].

In the widely cited report by Sir Nicholas Stern, on the economics of climate change, a long-term discount rate of 1.4% real was used. For a lengthy discussion of the issues involved, see http://ase.tufts.edu/gdae/pubs/rp/sterndebatereport.pdf.

Note that the analysis of effects on ratepayers captures effects on very different groups or individuals. Each of these individuals faces their own effective "cost of capital" or interest rate and as such the discounting of ratepayer effects has aspects that are more akin to a social type of discount rate than an entirely corporate focused discount rate. The merits of applying a low discount rate to resource plan analysis as a sensitivity test (similar to a high discount rate sensitivity test) is to determine if the decision being made would vary if a different discount rate was chosen. If a particular plan is dominant at a standard type of discount rate (e.g., 5.05% real) but a different plan became dominant at a different discount rate within the sensitivity band (1.86% to 10% real) then further consideration should be required to aspects such as mitigating risk, revised benefit sharing across time horizons, etc. In Hydro's NFAT Business case that did not occur. All three discount rate scenarios are reviewed below.

Plan 4 (K19/Gas/250MW) largely dominates Plan 14 (PDP) at the standard discount rate (5.05% real), and further dominates at a high discount rate (10% real). See Figure 17 versus Figure 34 from Mr. Bowman's Pre-Filed Testimony Appendix C, reproduced below.

[1]Office of the Auditor General of Ontario, Oakville Power Plant Cancellation Costs Special Report, page 20 (October 2013). [Accessed here:] http://www.auditor.on.ca/en/reports_en/oakville_en.pdf

Figure 17: Plan 4 (K19/Gas/250MW) vs. Plan 14 (PDP) at <u>5.05%</u> Real Discount Rate - NPV of Incremental Domestic Costs as Compared to Plan 1 (All Gas) Expected Value ($ Millions)

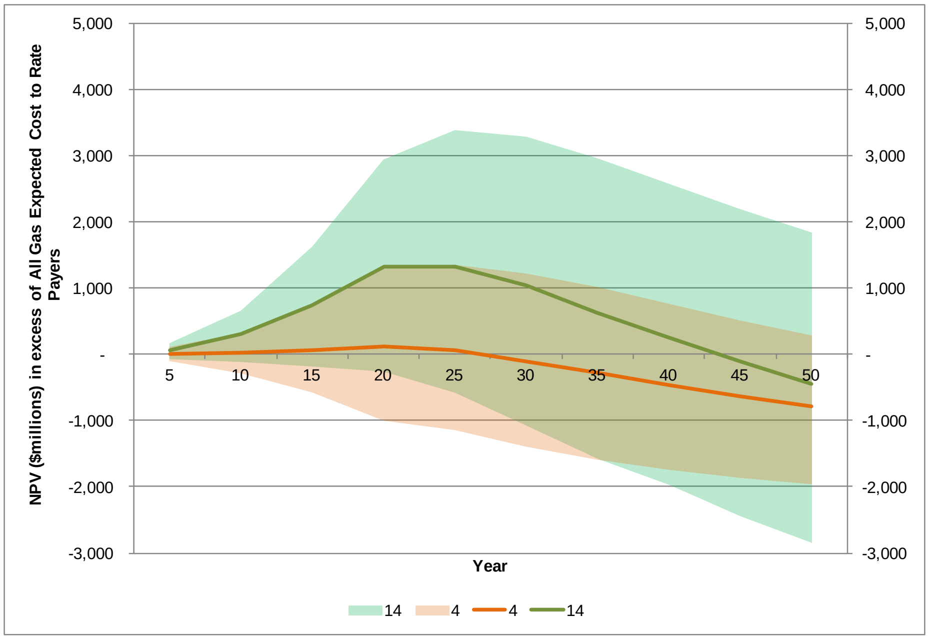
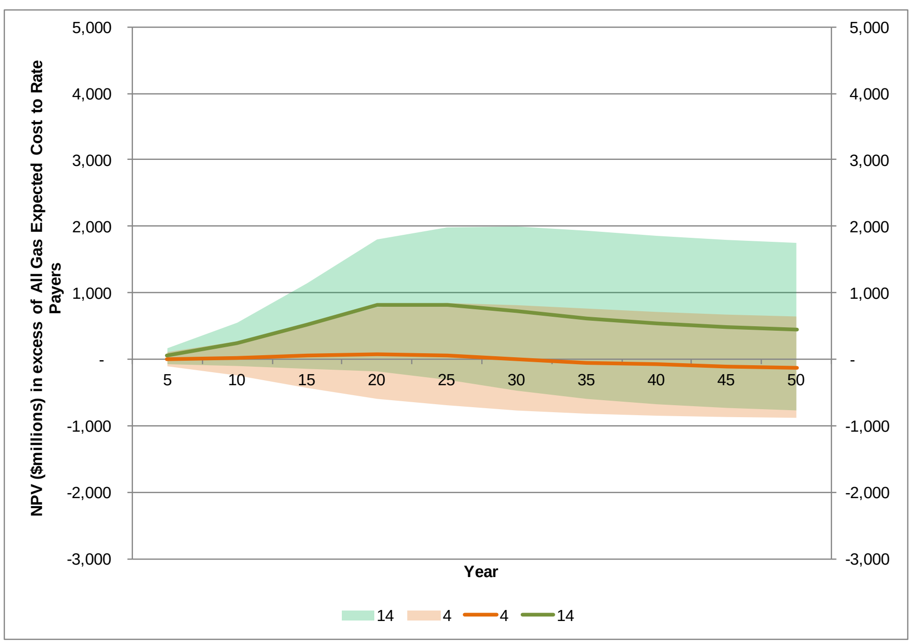
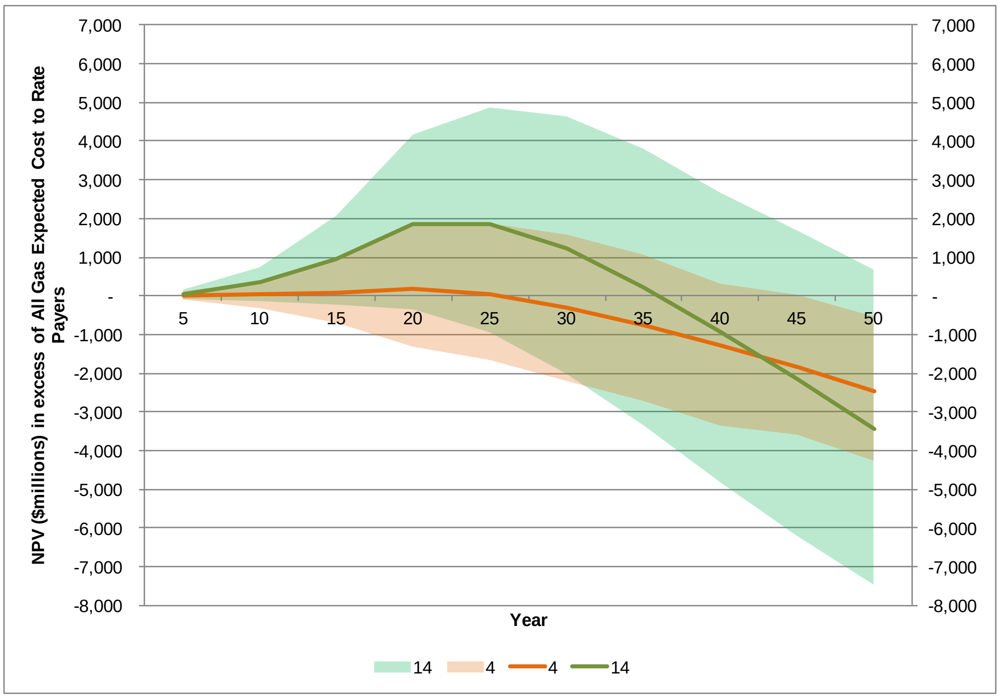


Figure 34: Plan 4 (K19/Gas/250MW) vs. Plan 14 (PDP) at <u>10%</u> Real Discount Rate- NPV of Incremental Domestic Costs as compared to Plan 1 (All Gas) Expected Value - ($ Millions)



At a low discount rate the reference is Mr. Bowman's Figure 30 from Appendix C, reproduced below. In this Figure, Plan 14 (PDP) slightly betters Plan 4 (K19/Gas/250MW) at the very long horizons, such as 50 years, but it remains much more risky (shown by the green area towards the top of the figure) and much more costly for the majority of the analysis horizon.

Figure 30: Plan 4 (K19/Gas/250MW) vs. Plan 14 (PDP) at <u>1.86%</u> Real Discount Rate- NPV of Incremental Domestic Ratepayer Costs as compared to Plan 1 (All Gas) Expected Value ($ Millions)



In short, the discount rate sensitivity tests indicate that the rate impact issues associated with Plan 14 (PDP) are more fundamental, rather than simply analytical. In addition, this analysis does not exhibit/expose a basis for attempting to address the rate impact issues through some form of altered sharing between near-term and long-term future ratepayers, as the NPV does not indicate a likely windfall for long-term benefits to future ratepayers that can be somehow brought forward. This is a reason that has led to Mr. Bowman's suggestion that in order to make Plan 14 (PDP) potentially viable, a revised benefit sharing between government and ratepayers is necessary.

(b)

Mr. Bowman's Appendix C recommends use of the 5.05% real discount rate as the main analytical option, with comparisons to 1.86% and 10% real rates as a sensitivity analysis.

As the major risk variables are appropriately modeled in the underlying financial scenarios, Mr. Bowman believes risk can be dealt with as follows:

- Largely risk is appropriately dealt with via the P10/P90 range, which Mr. Bowman applied in Appendix C. A further adjustment to the discount rate is not necessary.
- The only exception is the extra analysis of the low export price/low gas price sensitivity completed by Mr. Bowman in Appendix C at Figures 21 and 22. This additional risk-based analysis was completed to capture a particularly notable exacerbated risk for industrial customers, as discussed at PUB/MIPUG I-2(a). The result of that analysis was a rate scenario for Plan 4 (K19/Gas/250MW) that was higher than Plan 1 (All Gas), but not excessively higher under the circumstances. In contrast Plan 14 (PDP) reflects a much higher potential rate impact under this risk scenario. For this reason, Plan 4 (K19/Gas/250MW) was not ruled out, but Plan 14 (PDP) was further concluded to be disadvantageous for ratepayers under current assumptions.

SUBJECT:

REFERENCE: MIPUG Report Page 4-4 -4-6 Appendix C Page C-28

PREAMBLE:

InterGroup's analysis of ratepayer and government impacts are based on the probabilities established by MH. The analysis outcomes are impacted if different probabilities are applied.

QUESTION:

a) Please refile tables 3,4,5,6 based on changed probabilities for low export prices and a higher probability for higher capital cost scenarios and comment on the impact on plan preferences.

b) Please indicate whether InterGroup believes the probabilities established by MH are reasonable.

ANSWER:

(a)

Tables 3 through 6 have been updated to show the NPV of Costs/Benefits as requested. These tables are all based on fixing Export/Energy Prices at the Low sensitivity level, and the Capital Cost scenario at the High sensitivity level. Variability still occurs for the different Interest Rate/Economic Conditions, with Reference (in bold) and the High Economic Condition and Low Economic Condition (in brackets). The tables are broken out into ratepayers, government and Total. The amounts are compared to the Expected Value (EV) for Plan 1 (All Gas) for all 27 sensitivity scenarios (i.e. the same comparison as the original tables).

In comparison to the original Tables 3 through 6[1] which included all 27 scenarios the Government benefits have not changed substantially from the EVs. This is to be expected considering the range of risk for government returns is very narrow, as explained in Mr. Bowman's pre-filed Testimony, Appendix C[2]. The result of these large government benefits under a low energy price and high capital cost scenario (i.e.

[1] See CAC/MIPUG I-11 for corrected tables (as a slight error was found in the original tables for Plan 13).
[2] Section 5.0: Government Benefits, and specifically shown in Figures 25 and 25 on pages C-37 and C-38.

increased costs and decreased revenues) is borne solely by the ratepayers, as the Tables show, which results in very large cost to ratepayers over the original Tables.

Of note, the Total Plan Benefits for Plan 14 (PDP) are the highest; however all of this benefit (and then some) is seen by the government under the current financial arrangements.

Table 3: NPV for Reference (High/Low) Economic Conditions - Total Benefits to Ratepayers and Government at Year 20 (2031/32) with Low Export Prices and High Capital Costs Across all Economic Conditions Compared to Plan 1 Expected Value ($ Millions)

NPV of (Cost)/Benefit at 20 years ($ Millions) [High/Low]	**Pthwy 1**	**Pthwy 2**		**Pthwy 3**		**Pthwy 4**		**Pthwy 5**
	Plan 1	**Plan 7**	**Plan 2**	**Plan 4**	**Plan 13**	**Plan 6**	**Plan 12**	**Plan 14**
Ratepayer Benefit	**(600)** [(891)/ (55)]	**(1,962)** [(2,553)/ (1,053)]	**(1,221)** [(1,570) /(332)]	**(1,276)** [(1,767) /(361)]	**(3,000)** [(3,954)/ (1,546)]	**(1,536)** [(2,074) /(586)]	**(2,241)** [(2,816/ (1,223)]	**(2,913)** [(3,849)/ (1,453)]
Government Benefit	**(57)** [(395)/ 202]	**1,636** [1,378/ 1,840]	**1,373** [1,101/ 1,613]	**1,330** [895/ 1,648]	**3,144** [2,809/ 3,372]	**1,331** [876/ 1,671]	**2,893** [2,571 /3,117]	**3,179** [2,819/ 3,437]
Total Plan Benefits	**(657)** [(1,286)/ 147]	**(326)** [(1,175)/ 787]	**152** [(469)/ 1,281]	**54** [(873)/ 1,286]	**143** [(1,144)/ 1,826]	**(205)** [(1,198) /1,085]	**652** [(245)/ 1,894]	**266** [(1,030)/ 1,983]

Table 4: NPV for Reference (High/Low) Economic Conditions - Total Benefits to Ratepayers and Government at Year 30 (2041/42) with Low Export Prices and High Capital Costs Across all Economic Conditions Compared to Plan 1 Expected Value ($ Millions)

NPV of (Cost)/Benefit at 30 years ($ Millions) [High/Low]	Pthwy 1	Pthwy 2		Pthwy 3		Pthwy 4		Pthwy 5
	Plan 1	Plan 7	Plan 2	Plan 4	Plan 13	Plan 6	Plan 12	Plan 14
Ratepayer Benefit	**(610)** [(938) /202]	**(2,297)** [(2,995)/ (931)]	**(1,579)** [(1,949) /(313)]	**(1,447)** [(1,864) /(217)]	**(3,692)** [(4,642)/ (1,717)]	**(1,762)** [(2,226) /(492)]	**(3,276)** [(4,082)/ (1,558)]	**(3,434)** [(4,330)/ (1,463)]
Government Benefit	**(42)** [(407) /213]	**2,012** [1,727/ 2,197]	**1,716** [1,403/ 1,953]	**1,645** [1,143/ 1,970]	**3,825** [3,425/ 4,043]	**1,647** [1,124/ 1,994]	**3,721** [3,388/ 3,891]	**3,885** [3,457/ 4,130]
Total Plan Benefits	**(652)** [(1,346) /416]	**(284)** [(1,268)/ 1,266]	**137** [(545)/ 1,639]	**198** [(721)/ 1,753]	**133** [(1,217)/ 2,326]	**(114)** [(1,102) /1,502]	**445** [(694)/ 2,333]	**451** [(873)/ 2,667]

Table 5: NPV for Reference (High/Low) Economic Conditions - Total Benefits to Ratepayers and Government at Year 40 (2051/52) with Low Export Prices and High Capital Costs Across all Economic Conditions Compared to Plan 1 Expected Value ($ Millions)

NPV of (Cost)/Benefit at 40 years ($ Millions) [High/Low]	Pthwy 1	Pthwy 2		Pthwy 3		Pthwy 4		Pthwy 5
	Plan 1	Plan 7	Plan 2	Plan 4	Plan 13	Plan 6	Plan 12	Plan 14
Ratepayer Benefit	**(501)** [(839)/ 484]	**(1,987)** [(2,600)/ (457)]	**(1,395)** [(1,608) /(53)]	**(1,214)** [(1,542) /134]	**(3,286)** [(4,031)/ (1,223)]	**(1,483)** [(1,847) /(113)]	**(3,055)** [(3,701)/ (1,179)]	**(3,016)** [(3,708)/ (960)]
Government Benefit	**(22)** [(407)/ 233]	**2,147** [1,818/ 2,349]	**1,876** [1,505/ 2,148]	**1,784** [1,234/ 2,136]	**4,072** [3,594/ 4,334]	**1,782** [1,207/ 2,157]	**4,031** [3,630/ 4,234]	**4,138** [3,635/ 4,429]
Total Plan Benefit	**(523)** [(1,246)/ 716]	**161** [(782)/ 1,892]	**481** [(103)/ 2,095]	**570** [(308)/ 2,270]	**786** [(437)/ 3,111]	**298** [(640)/ 2,044]	**976** [(71)/ 3,055]	**1,122** [(73)/ 3,468]

Table 6: NPV for Reference (High/Low) Economic Conditions - Total Benefits to Ratepayers and Government at Year 50 (2061/62) with Low Export Prices and High Capital Costs Across all Economic Conditions Compared to Plan 1 Expected Value ($ Millions)

NPV of (Cost)/Benefit at 50 years ($ Millions) [High/Low]	**Pthwy 1**	**Pthwy 2**		**Pthwy 3**		**Pthwy 4**		**Pthwy 5**
	Plan 1	**Plan 7**	**Plan 2**	**Plan 4**	**Plan 13**	**Plan 6**	**Plan 12**	**Plan 14**
Ratepayer Benefit	**(413)** [(667)/ 548]	**(1,681)** [(2,126)/ (212)]	**(1,065)** [(1,067) /137]	**(928)** [(1,104) /343]	**(2,823)** [(3,332)/ (880)]	**(1,162)** [(1,368) /120]	**(2,652)** [(3,058) /(875)]	**(2,538)** [(2,990)/ (607)]
Government Benefit	**(15)** [(412)/ 250]	**2,194** [1,835/ 2,424]	**1,911** [1,503/ 2,224]	**1,828** [1,251/ 2,211]	**4,159** [3,635/ 4,470]	**1,819** [1,215/ 2,226]	**4,139** [3,692/ 4,388]	**4,229** [3,679/ 4,569]
Total Plan Benefit	**(429)** [(1,079)/ 798]	**514** [(291)/ 2,212]	**846** [437/ 2,362]	**900** [147/ 2,554]	**1,336** [303/ 3,590]	**657** [(153)/ 2,346]	**1,487** [634/ 3,513]	**1,690** [689/ 3,962]

Under the above conditions, with low energy prices and high capital costs, the basic conclusion is that ratepayers would be least impacted (therefore best served) by Plan 1 (All Gas).

While government benefits are large under all alternatives to Plan 1 (All Gas) even in the longest horizons (40 - 50 years) the EVs for ratepayers remain negative in all plans. This leads to “Total Plan Benefits” that are modest at best up to at least year 30.

(b)

Mr. Bowman has no basis to develop probability estimates that would alter the estimates developed by Manitoba Hydro. The only estimate of concern relates to the effective significant weighting of the “low” export and carbon price scenario as assigned by Hydro, as part of developing the probabilities for the highest impact factors (30% chance of occurrence[3]).

Mr. Bowman does note that the low energy price scenario used in the NFAT is challenged by two factors which may make this an overly pessimistic low forecast:

[3] NFAT Business Case, Appendix 9.3: Economic Evaluation Documentation, page 60 (August 2013).

1) The 2012/13 export price forecast was adjusted for use in the NFAT submission at a time of highly depressed assumptions regarding the market minimums. While the Reference export prices were revised downward only 8%, the Low price scenarios were revised downwards 32%[4]. Since this time, in preparing the 2013/14 forecast update, export prices have been revised upward with Reference prices increasing 7% and Low prices increasing 41%[5]. In short, the Low price scenarios used in the NFAT filing (apart from Chapter 13, which uses the 2013/14 forecast update) represents almost a needle-point low that may no longer be considered a reasonable low point forecast.

2) While Hydro does not file all of the assumptions regarding carbon pricing, the indications are that Low scenarios for both export pricing scenarios[6] and domestic[7] include no carbon pricing effects throughout the entire modeling horizon. This is likely inconsistent with reasonable long-range expectations regarding carbon pricing. While there remains a valid basis for debate about the exact process and timeline to implement possible near-term carbon pricing regimes, it would seem to be reasonable to assume that some form of carbon pricing (direct or indirect) would be a component of any long-term forecast. This is in part based on significant international discussion about longer-term plans to reduce carbon, including the often-cited 80% reduction that is expected by 2050[8].

[4] NFAT Business Case, Appendix 9.3: Economic Evaluation Documentation, page 11-12 (August 2013).
[5] NFAT Business Case, Appendix 9.3: Economic Evaluation Documentation, page 13 (August 2013).
[6] NFAT Business Case, Appendix 3.1: Long-Term Price Forecast for Manitoba Hydro's Export Market in MISO – The Brattle Group, page 28.
[7] CAC/MH I-203b
[8] For example with respect to the United States: http://www.whitehouse.gov/the-press-office/remarks-president-morning-plenary-session-united-nations-climate-change-conference

SUBJECT:

REFERENCE: **MIPUG Report Appendix C Page C-43**

PREAMBLE:

QUESTION:

a) Please superimpose the low discount rate plots on figures 31 and 32 and provide tables of supporting data points and commentary.

ANSWER:

(a)

Using the software available, it is not possible to graph more than 2 "cones" on any given image. Figures 27 and 31 (comparing Plan 1 (All Gas) and Plan 4 (K19/Gas/250MW)) and Figures 28 and 32 (comparing Plan 4 (K19/Gas/250MW) and Plan 14 (PDP)) at 1.86% and 10% real discount rates respectively have been reproduced below on the same axis scale for comparison purposes. Table 1 provides the supporting data points for each plan under each real discount rate.

Figure 27: NPV Total Amount Paid in Rates at <u>1.86%</u> Real Discount Rate Plan 1 vs. Plan 4 ($ Millions)

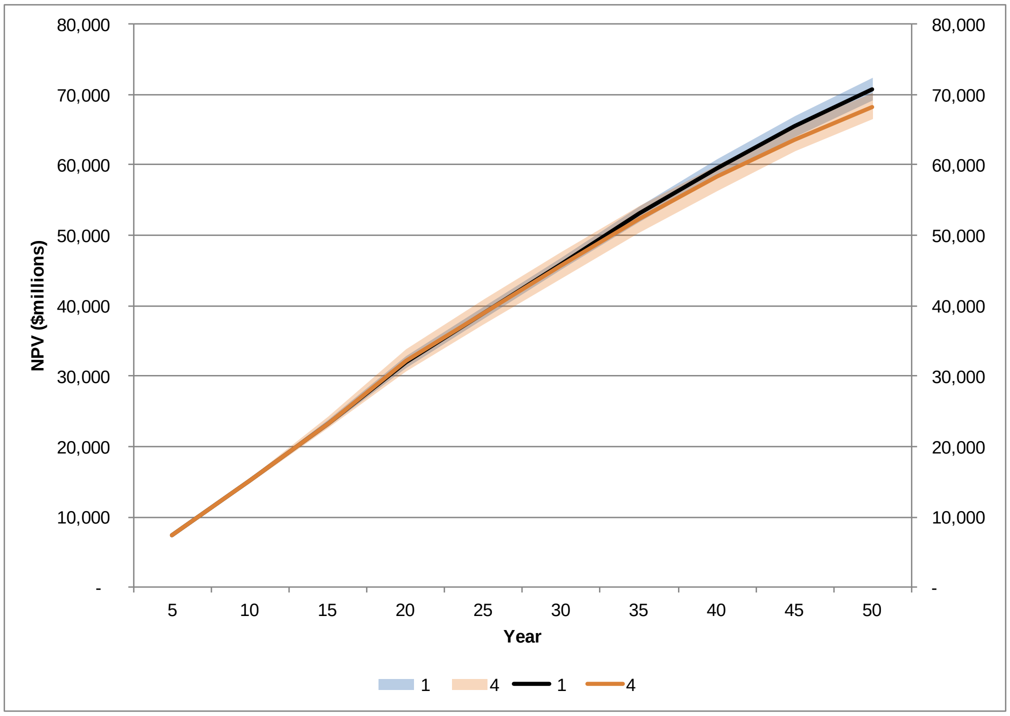


Figure 31: NPV Total Amount Paid in Rates at <u>10%</u> Real Discount Rate Plan 1 vs. Plan 4 ($ Millions)

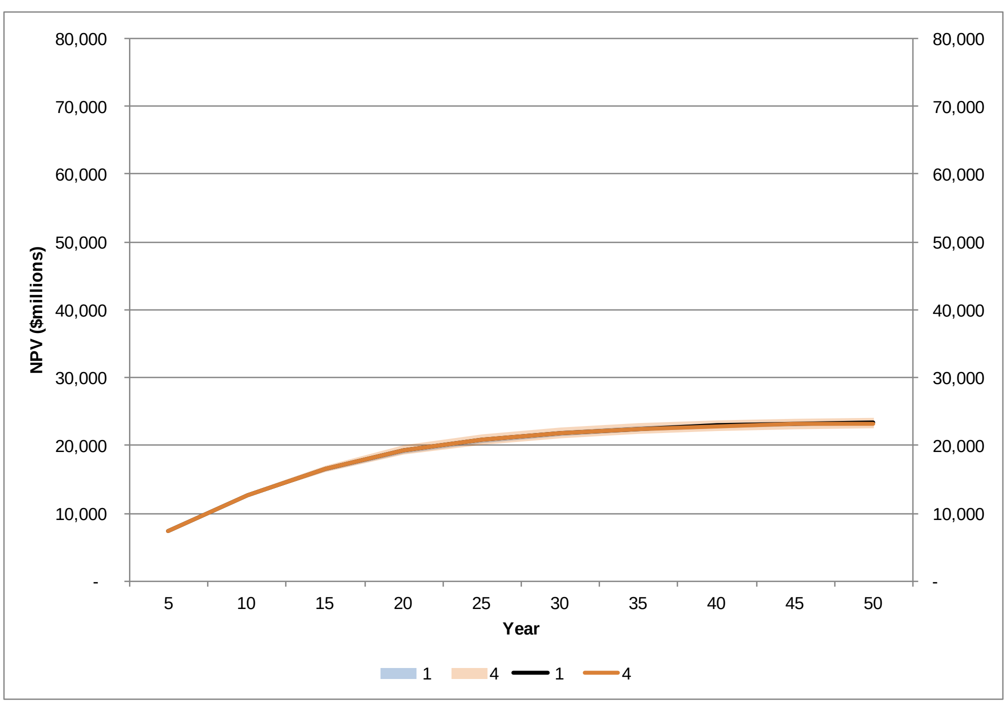


Figure 28: NPV Total Amount Paid in Rates at <u>1.86%</u> Real Discount Rate Plan 4 vs. Plan 14 ($ Millions)

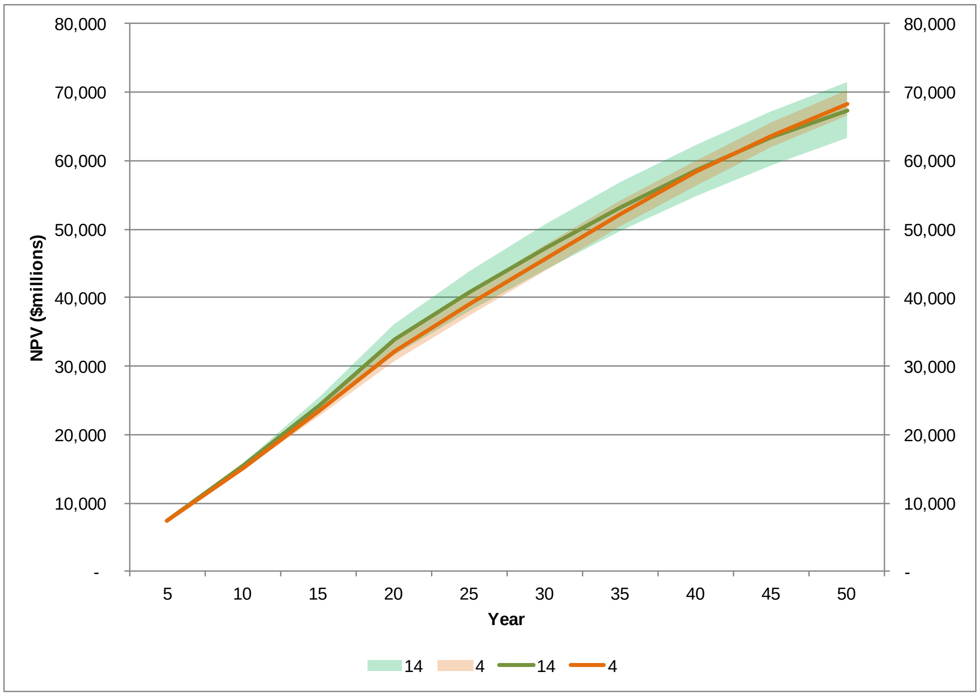


Figure 32: NPV Total Amount Paid in Rates at <u>10%</u> Real Discount Rate Plan 4 VS. Plan 14 ($ Millions)

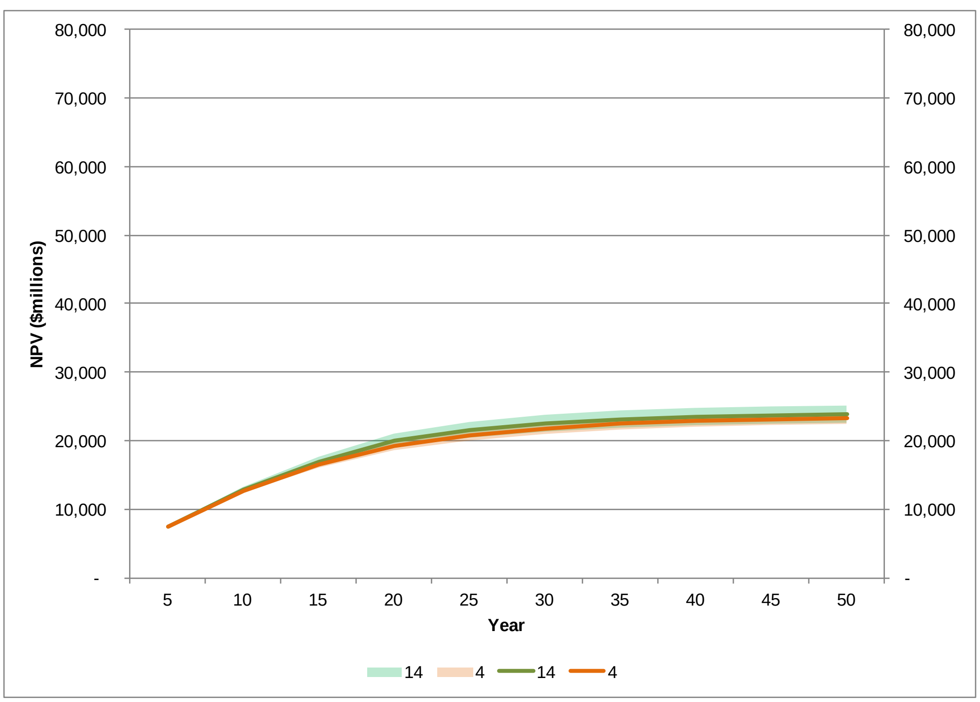


Table 1: Total Amount Paid in Rates Expected Value (P10/P90) for Plan 1 (All Gas), Plan 4 (K19/Gas/250MW) and Plan 14 (PDP) at 1.86% and 10% Real Discount Rates

Total Expected Value NPV of Amount Paid in Rates [P10/P90] **($ Millions)**	**Plan 1 (All Gas) 1.86% Real Discount Rate**	**Plan 1 (All Gas) 10% Real Discount Rate**	**Plan 4 (K19/Gas/ 250MW) 1.86% Real Discount Rate**	**Plan 4 (K19/Gas/ 250MW) 10% Real Discount Rate**	**Plan 14 (PDP) 1.86% Real Discount Rate**	**Plan 14 (PDP) 10% Real Discount Rate**
Year 5	**7,366** [7,266/ 7,454]	**7,399** [7,296/ 7,488]	**7,371** [7,263/ 7,476]	**7,404** [7,294/ 7,508]	**7,422** [7,295/ 7,536]	**7,450** [7,323/ 7,562]
Year 10	**15,099** [14,876/ 15,329]	**12,687** [12,508/ 12,872]	**15,129** [14,774/ 15,458]	**12,708** [12,442/ 12,958]	**15,450** [14,973/ 15,846]	**12,934** [12,583/ 13,233]
Year 15	**23,278** [22,815/ 23,761]	**16,494** [16,208/ 16,790]	**23,365** [22,572/ 24,196]	**16,542** [16,061/ 16,996]	**24,220** [23,059/ 23,359]	**17,012** [16,347/ 17,633]
Year 20	**31,927** [31,114/ 32,810]	**19,235** [18,842/ 19,646]	**32,106** [30,604/ 33,757]	**19,312** [18,638/ 20,023]	**33,799** [31,587/ 36,106]	**20,045** 19,050/ 21,032]
Year 25	**38,976** [38,128/ 39,844]	**20,759** [20,380/ 21,143]	**39,033** [37,308/ 40,842]	**20,810** [20,066/ 21,609]	**40,844** [38,043/ 43,854]	**21,573** [20,449/ 22,736]
Year 30	**46,027** [45,143/ 46,821]	**21,797** [21,424/ 22,174]	**45,714** [43,817/ 47,604]	**21,794** [21,024/ 22,614]	**47,261** [44,021/ 50,673]	**22,520** [21, 322/ 23,788]
Year 35	**53,056** [51,882/ 54,091]	**22,502** [22,123/ 22,864]	**52,310** [50,329/ 54,111]	**22,455** [21,680/ 23,268]	**53,267** [49,724/ 56,869]	**23,123** [21,903/ 24,429]
Year 40	**59,595** [58,262/ 60,814]	**22,949** [22,595/ 23,298]	**58,331** [56,229/ 59,902]	**22,868** [22,098/ 23,665]	**58,668** [54,791/ 62,273]	**23,493** [22,271/ 24,800]
Year 45	**65,488** [63,966/ 66,942]	**23,224** [22,876/ 23,563]	**63,634** [61,889/ 65,508]	**23,115** [22,352/ 23,899]	**63,335** [59,298/ 67,192]	**23,711** [22,491/ 25,014]
Year 50 – Complete Analysis	**70,736** [69,174/ 72,395]	**23,390** [23,038/ 23,723]	**68,277** [66,464/ 70,195]	**23,263** [22,507/ 24,037]	**67,294** [63,283/ 71,427]	**23,836** [22,619/ 25,136]

The above analysis shows the effects of varying the discount rate on the calculated NPVs of ratepayer costs. The NPV of rates to be paid in future is sensitive to the discount rate chosen. This is an expected analytical outcome. A few additional observations:

- Under a high discount rate sensitivity, Plan 4 (K19/Gas/250MW) and Plan 1 (All Gas) are comparable in terms of Expected Value (EV). The high discount rate serves to negate, to a degree, the long-term benefits of Plan 4 (K19/Gas/250MW), but not all.
- Under a low discount rate sensitivity, Plan 14 (PDP) between years 40 and 45 does begin to show an EV lower (as in lower amounts paid by ratepayers) than Plan 4 (K19/Gas/250MW). This is an interesting outcome, but only serves to suggest that an individual with a very low time preference for money (i.e., is not concerned about savings for the future at a very low rate), a very long-term horizon (well in excess of the cross-over point of 40 years) and a high tolerance for risk (noting the extent of time when the Plan 14 (PDP) P10/P90 range is well above the range for Plan 4 (K19/Gas/250MW)) may elect to proceed with Plan 14 (PDP) under current conditions. Otherwise Plan 14 (PDP) is not the preferred outcome under current conditions.

SUBJECT:

REFERENCE: MIPUG Report Page Appendix C Page C-8 17 Figures 1-12

PREAMBLE:

QUESTION:

a) Please refile the waterfall graphs in figure 1 - 12 based on lower export prices and higher capital costs and comment on the impact.

b) Please refile the waterfall analysis based on the high discount rate basis and provide comments on the impact.

ANSWER:

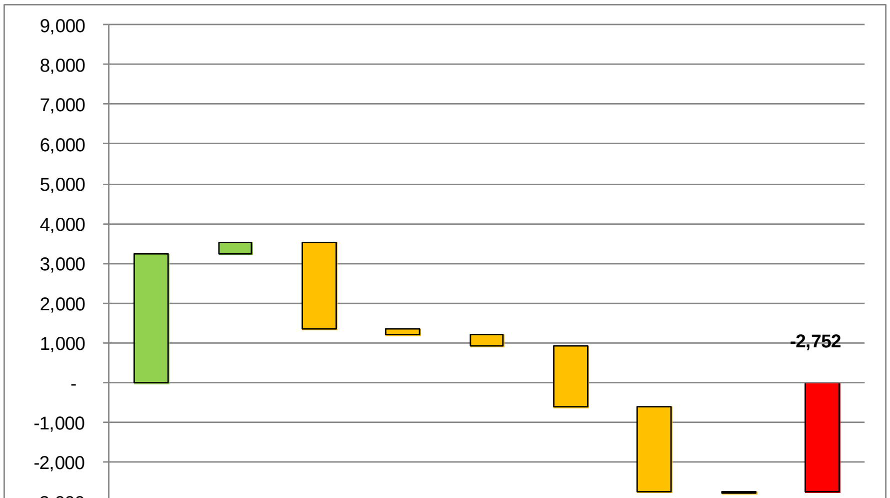
(a)

Figures 1 through 6 show the waterfall graphs for Plan 14 (PDP) compared to Plan 1 (All Gas) for the Reference Economic Conditions, Low Export Prices and High Capital Costs scenario. These graphs reflect a pessimistic scenario. If this represented the expected outcome, this analysis would reflect a strong conclusion to reject Plan 14.

Note that this sequence continues to show net benefits to Manitoba overall from the projects as compared to Plan 1 (All Gas) for the entire sequence of 6 graphs (i.e., the value remaining after the first five columns – seen in the data table as the amount after O&M is deducted from revenues, which is then split between the categories of: Gov't Charges, Added to Reserves, FN Partners and Ratepayers). These benefits are smaller than under the REF-REF-REF conditions[1], as they start at $0.938 billion NPV at year 25 and grow to $2.119 billion by year 50. The NPV benefits to government remain close to $4 billion throughout the time horizon (the sum of Added to Reserves, which represents the growth in the Government's Shareholder Equity in Hydro, and Gov't Charges) such that ratepayers are materially worse off throughout the horizon (as shown by the final column); from $2.752 billion worse off in the period up to year 25, improving to $2.125 billion worse off in the entire period to year 50.

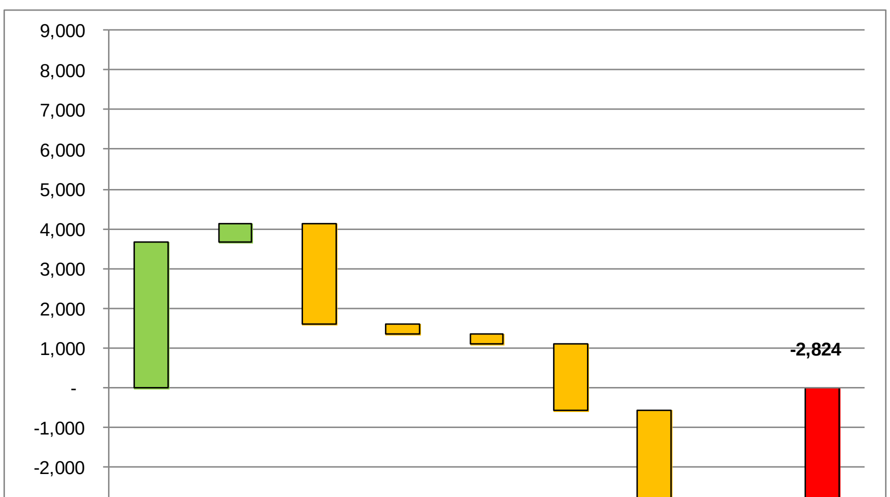
[1] Found in MIPUG Appendix C, Figures 1 and 3 - 7 on pages C-8 through C-13.

Figure 1: Year 25 – REF Interest-LOW Export Prices-HIGH Capital Costs Plan 1 vs. Plan 14 (NPV $ Millions) at 5.05% Real Discount Rate



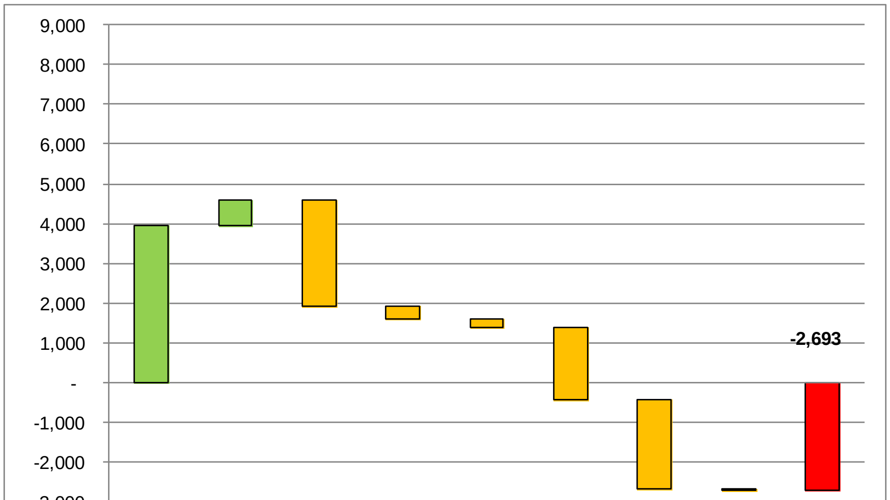
	Added Export	Fuel&PP Sav	Interest	Depreciation	O&M	Gov't Charges	Added to Reserves	FN Partners	Ratepayers
ends -									-2,752
before	-	3,246	3,510	1,346	1,214	938	-592	-2,732	
after	3,246	3,510	1,346	1,214	938	-592	-2,732	-2,752	

Figure 2: Year 30 – REF Interest-LOW Export Prices-HIGH Capital Costs Plan 1 vs. Plan 14 (NPV $ Millions) at 5.05% Real Discount Rate



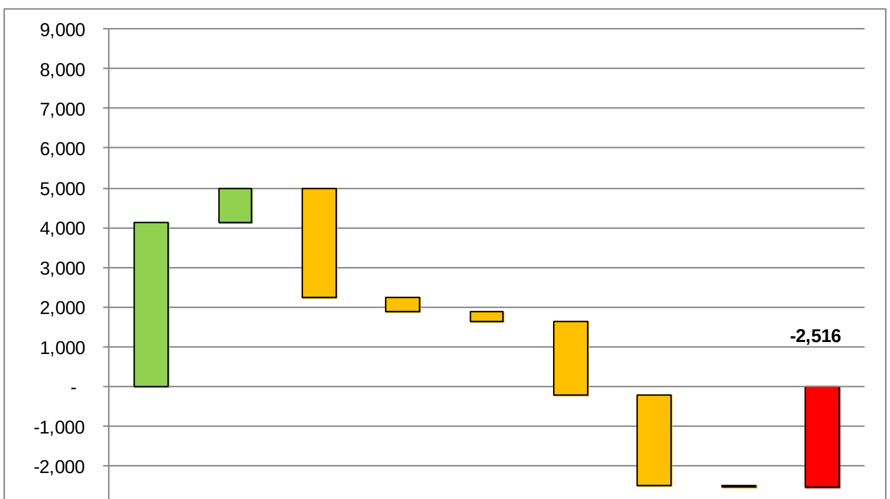
	Added Export	Fuel&PP Sav	Interest	Depreciation	O&M	Gov't Charges	Added to Reserves	FN Partners	Ratepayers
ends -									-2,824
before	-	3,667	4,123	1,619	1,369	1,104	-582	-2,799	
after	3,667	4,123	1,619	1,369	1,104	-582	-2,799	-2,824	

Figure 3: Year 35 – REF Interest-LOW Export Prices-HIGH Capital Costs Plan 1 vs. Plan 14 (NPV $ Millions) at 5.05% Real Discount Rate



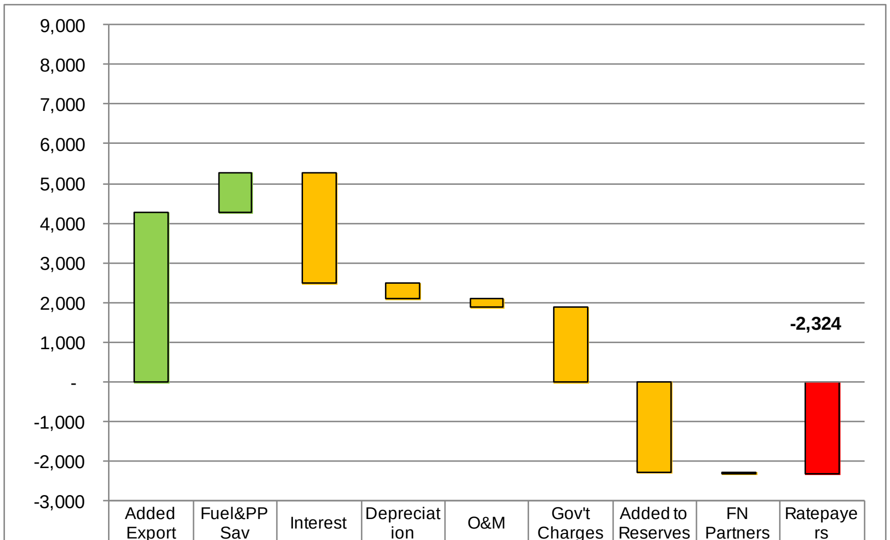
	Added Export	Fuel&PP Sav	Interest	Depreciation	O&M	Gov't Charges	Added to Reserves	FN Partners	Ratepayers
ends -									-2,693
before	-	3,938	4,598	1,934	1,619	1,374	-410	-2,664	
after	3,938	4,598	1,934	1,619	1,374	-410	-2,664	-2,693	

Figure 4: Year 40 – REF Interest-LOW Export Prices-HIGH Capital Costs Plan 1 vs. Plan 14 (NPV $ Millions) at 5.05% Real Discount Rate



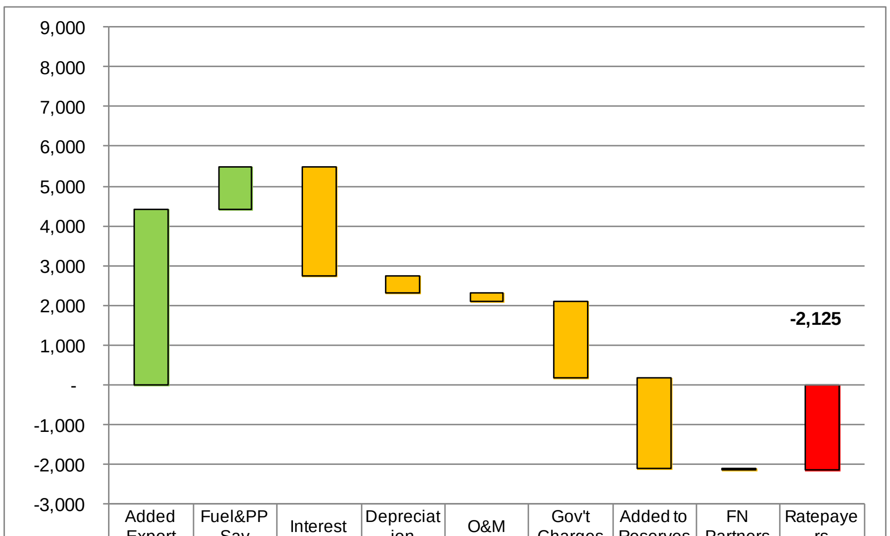
	Added Export	Fuel&PP Sav	Interest	Depreciation	O&M	Gov't Charges	Added to Reserves	FN Partners	Ratepayers
ends -									-2,516
before	-	4,136	4,975	2,232	1,872	1,645	-208	-2,484	
after	4,136	4,975	2,232	1,872	1,645	-208	-2,484	-2,516	

Figure 5: Year 45 – REF Interest-LOW Export Prices-HIGH Capital Costs Plan 1 vs. Plan 14 (NPV $ Millions) at 5.05% Real Discount Rate



	Added Export	Fuel&PP Sav	Interest	Depreciation	O&M	Gov't Charges	Added to Reserves	FN Partners	Ratepayers
ends -									-2,324
before	-	4,290	5,267	2,497	2,108	1,894	-5	-2,290	
after	4,290	5,267	2,497	2,108	1,894	-5	-2,290	-2,324	

Figure 6: Year 50 – REF Interest-LOW Export Prices-HIGH Capital Costs Plan 1 vs. Plan 14 (NPV $ Millions) at 5.05% Real Discount Rate

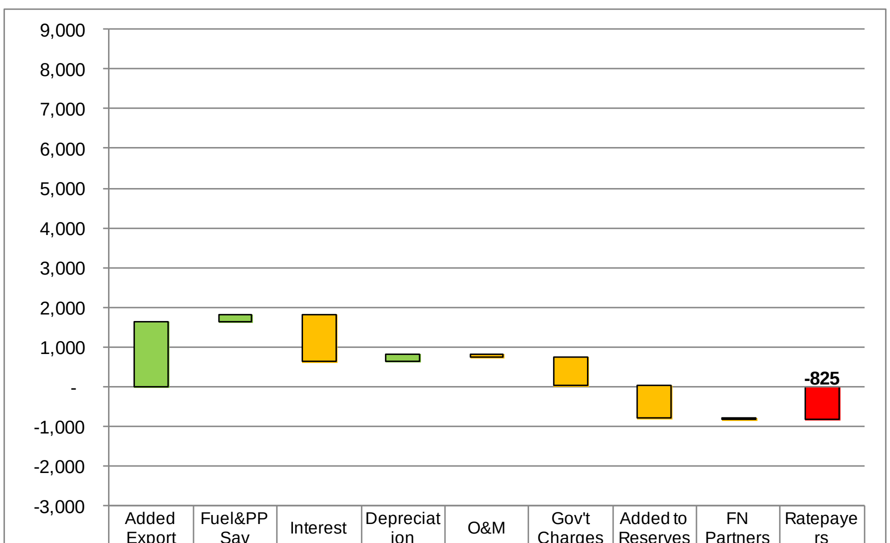


	Added Export	Fuel&PP Sav	Interest	Depreciation	O&M	Gov't Charges	Added to Reserves	FN Partners	Ratepayers
ends -									-2,125
before	-	4,410	5,495	2,727	2,319	2,119	194	-2,090	
after	4,410	5,495	2,727	2,319	2,119	194	-2,090	-2,125	

Figures 7 through 12 below show the waterfall graphs for Plan 4 (K19/Gas/250MW) as compared to Plan 1 (All Gas) for the scenario with Reference Economic Conditions, Low Export Prices and High Capital Costs for the five year increments from Year 25 to Year 50 for the Financial Analysis.

The trend is similar to Figures 1 - 6 above based on Plan 14 (PDP), in that consolidated benefits to Manitoba overall arise throughout the horizon shown, starting at $0.750 billion at year 25[2] and growing to $1.329 billion by year 50[3]. However the share of benefits allocated to government, either through growth in its value as shareholder of Hydro, or as Government charges, is so large as to lead to significant adverse impacts on ratepayers ($0.825 billion NPV by year 25 decreasing to $0.515 by year 50).

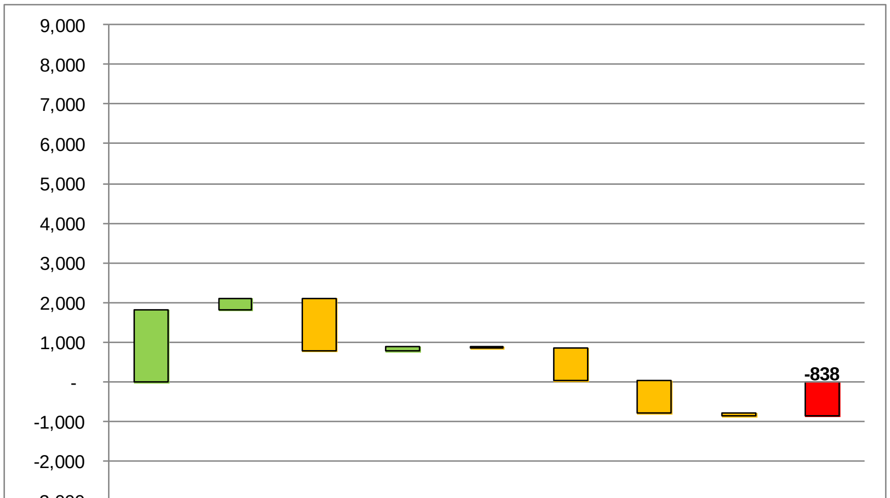
Figure 7: Year 25 – REF Interest-LOW Export Prices-HIGH Capital Costs Plan 1 vs. Plan 4 (NPV $ Millions) at 5.05% Real Discount Rate



	Added Export	Fuel&PP Sav	Interest	Depreciation	O&M	Gov't Charges	Added to Reserves	FN Partners	Ratepayers
ends -									-825
before	-	1,638	1,832	651	811	750	26	-788	
after	1,638	1,832	651	811	750	26	-788	-825	

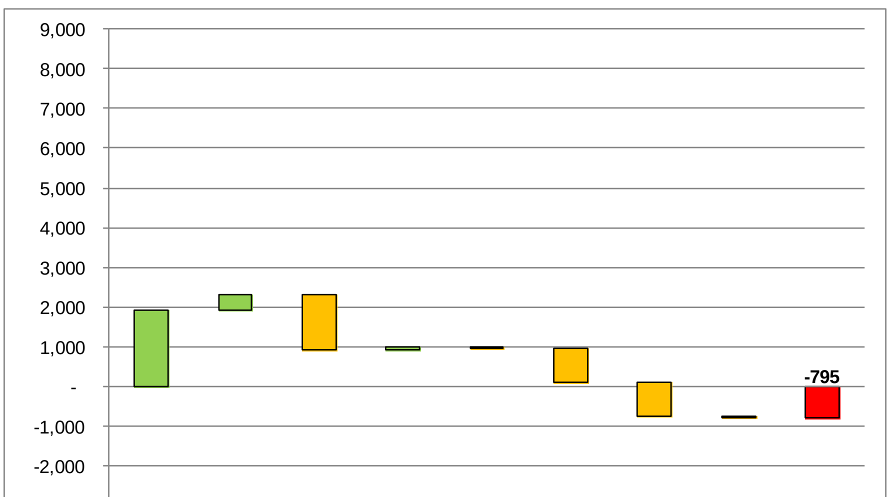
[2] Shown in Figure 7 above in the data table as the total revenue remaining after O&M is deducted for the period.
[3] Shown in Figure 12 below in the data table as the total revenue remaining after O&M is deducted for the period.

Figure 8: Year 30 – REF Interest-LOW Export Prices-HIGH Capital Costs Costs Plan 1 vs. Plan 4 (NPV $ Millions) at 5.05% Real Discount Rate



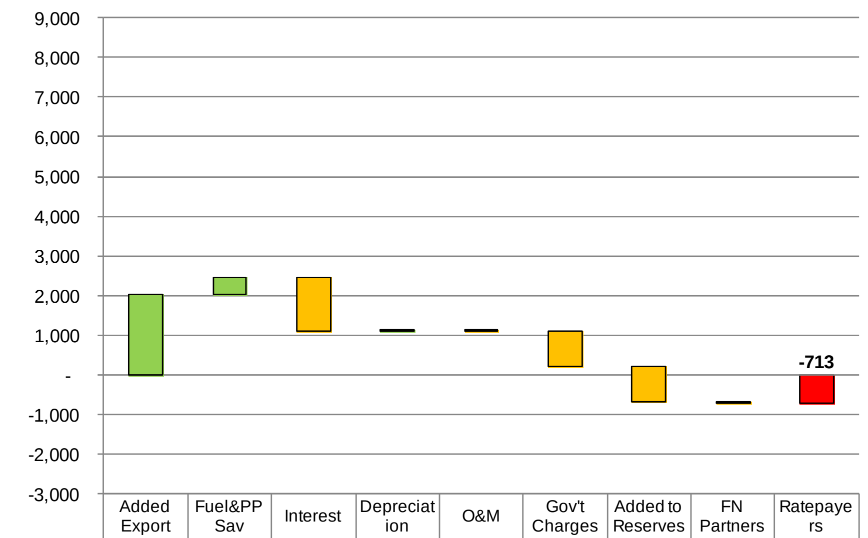
	Added Export	Fuel&PP Sav	Interest	Depreciation	O&M	Gov't Charges	Added to Reserves	FN Partners	Ratepayers
ends -									-838
before	-	1,808	2,092	793	905	850	51	-796	
after	1,808	2,092	793	905	850	51	-796	-838	

Figure 9: Year 35 – REF Interest-LOW Export Prices-HIGH Capital Costs Plan 1 vs. Plan 4 (NPV $ Millions) at 5.05% Real Discount Rate



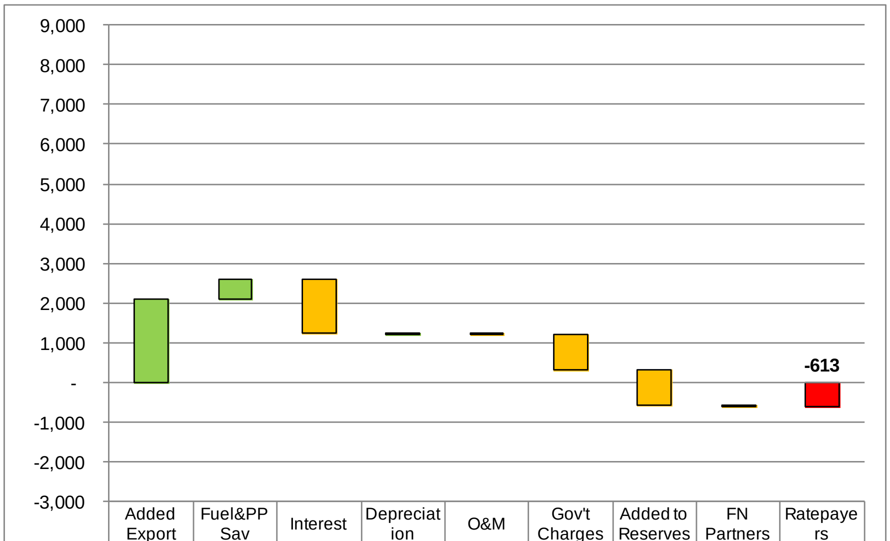
	Added Export	Fuel&PP Sav	Interest	Depreciation	O&M	Gov't Charges	Added to Reserves	FN Partners	Ratepayers
ends -									-795
before	-	1,935	2,299	944	1,015	965	114	-749	
after	1,935	2,299	944	1,015	965	114	-749	-795	

Figure 10: Year 40 – REF Interest-LOW Export Prices-HIGH Capital Costs Plan 1 vs. Plan 4 (NPV $ Millions) at 5.05% Real Discount Rate



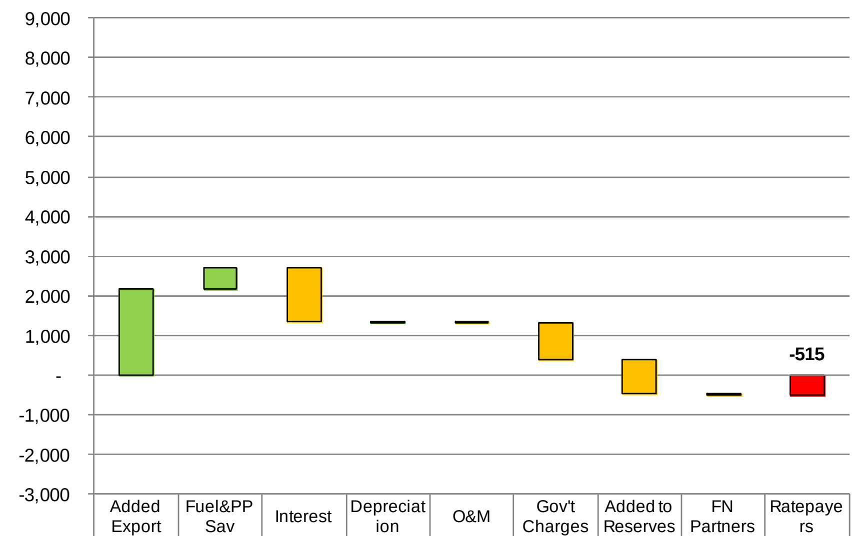
	Added Export	Fuel&PP Sav	Interest	Depreciation	O&M	Gov't Charges	Added to Reserves	FN Partners	Ratepayers
ends -									-713
before	-	2,033	2,467	1,097	1,139	1,093	205	-664	
after	2,033	2,467	1,097	1,139	1,093	205	-664	-713	

Figure 11: Year 45 – REF Interest-LOW Export Prices-HIGH Capital Costs Plan 1 vs. Plan 4 (NPV $ Millions) at 5.05% Real Discount Rate



	Added Export	Fuel&PP Sav	Interest	Depreciation	O&M	Gov't Charges	Added to Reserves	FN Partners	Ratepayers
ends -									-613
before	-	2,110	2,597	1,238	1,261	1,218	307	-562	
after	2,110	2,597	1,238	1,261	1,218	307	-562	-613	

Figure 12: Year 50 – REF Interest-LOW Export Prices-HIGH Capital Costs Plan 1 vs. Plan 4 (NPV $ Millions) at 5.05% Real Discount Rate



	Added Export	Fuel&PP Sav	Interest	Depreciation	O&M	Gov't Charges	Added to Reserves	FN Partners	Ratepayers
ends -									-515
before	-	2,170	2,698	1,360	1,369	1,329	404	-461	
after	2,170	2,698	1,360	1,369	1,329	404	-461	-515	

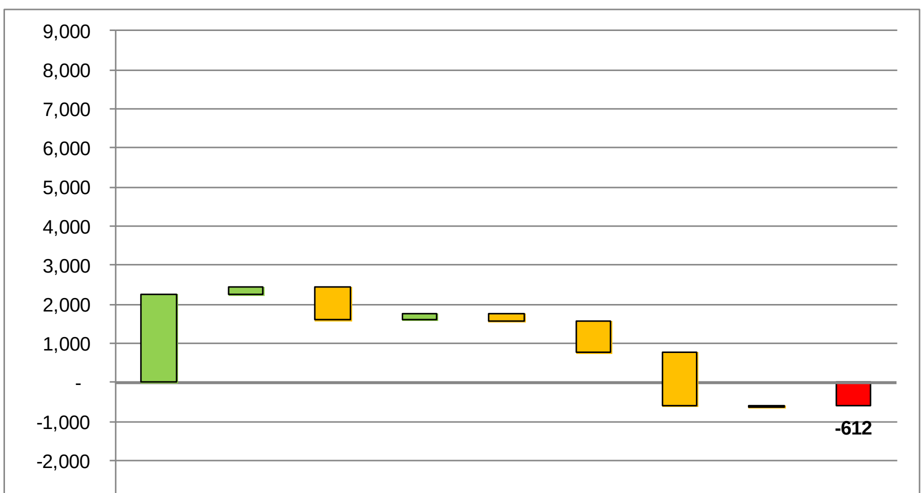
(b)

Figures 13 through 24 below utilize the 10% real discount rate for the Reference Economic Conditions, Reference Export Prices and Reference Capital Costs scenario. These figures illustrate the more severe discounting effect on NPVs leading to all bars being of smaller heights than under the figures in part (a) of this response.

Figures 13 through 18 show the waterfall graphs for Plan 14 (PDP) compared to Plan 1 (All Gas). At the 10% real discount rate Plan 14 (PDP) does not provide a financial benefit over Plan 1 (All Gas) over the 50 year analysis period.

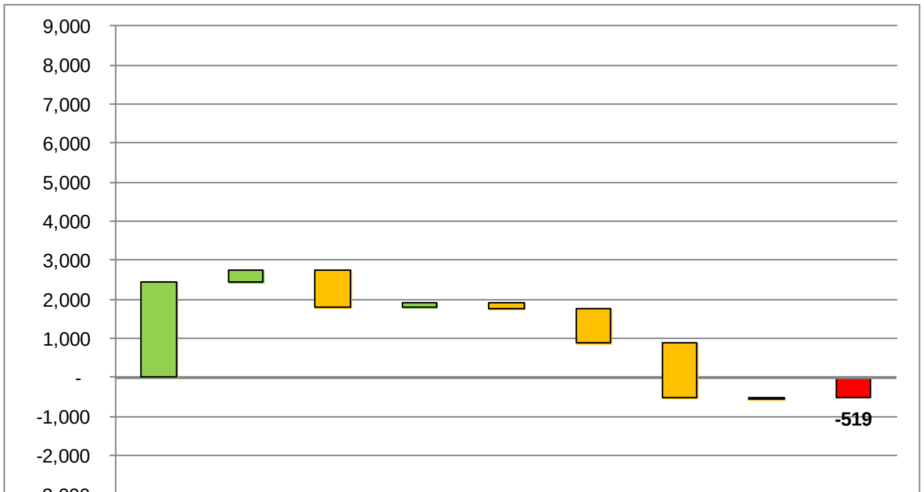
Figures 19 through 24 provide Plan 4 (K19/Gas/250MW) compared to Plan 1 (All Gas) at the same real discount rate of 10%. Similar to Plan 14 (PDP) the benefits of Plan 4 are reduced compared with the REF-REF-REF scenario; however Plan 4 benefits for ratepayers are positive over Plan 1 (All Gas) throughout the time horizon.

Figure 13: Year 25 - REF-REF-REF Plan 1 vs. Plan 14 (NPV $ Millions) at 10% Real Discount Rate



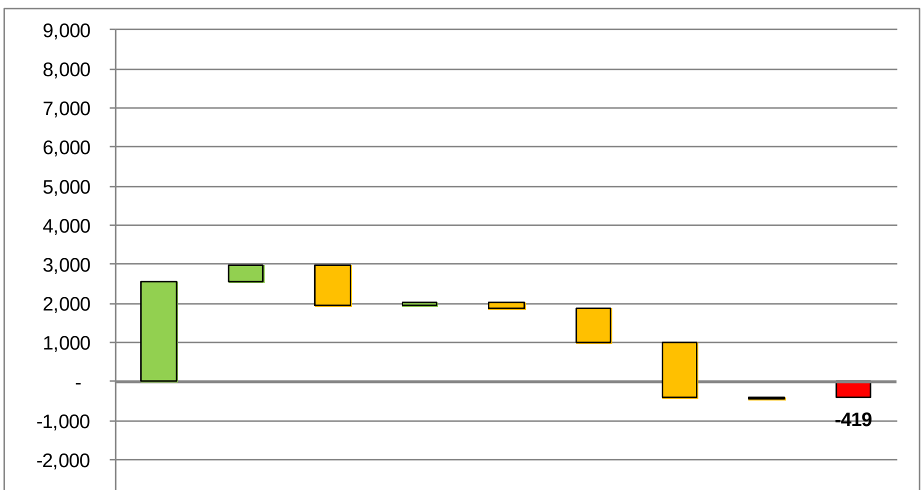
	Added Export	Fuel&PP Sav	Interest	Depreciat ion	O&M	Gov't Charges	Added to Reserves	FN Partners	Ratepaye rs
ends -									-612
before	-	2,239	2,453	1,586	1,743	1,575	753	-602	
after	2,239	2,453	1,586	1,743	1,575	753	-602	-612	

Figure 14: Year 30 - REF-REF-REF Plan 1 vs. Plan 14
(NPV $ Millions) at 10% Real Discount Rate



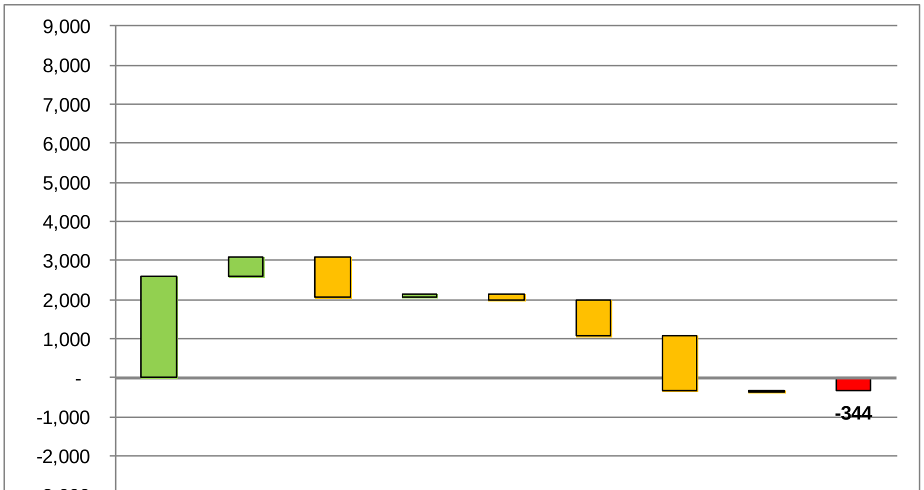
	Added Export	Fuel&PP Sav	Interest	Depreciation	O&M	Gov't Charges	Added to Reserves	FN Partners	Ratepayers
ends -									-519
before	-	2,440	2,762	1,791	1,906	1,742	873	-506	
after	2,440	2,762	1,791	1,906	1,742	873	-506	-519	

Figure 15: Year 35 - REF-REF-REF Plan 1 vs. Plan 14
(NPV $ Millions) at 10% Real Discount Rate



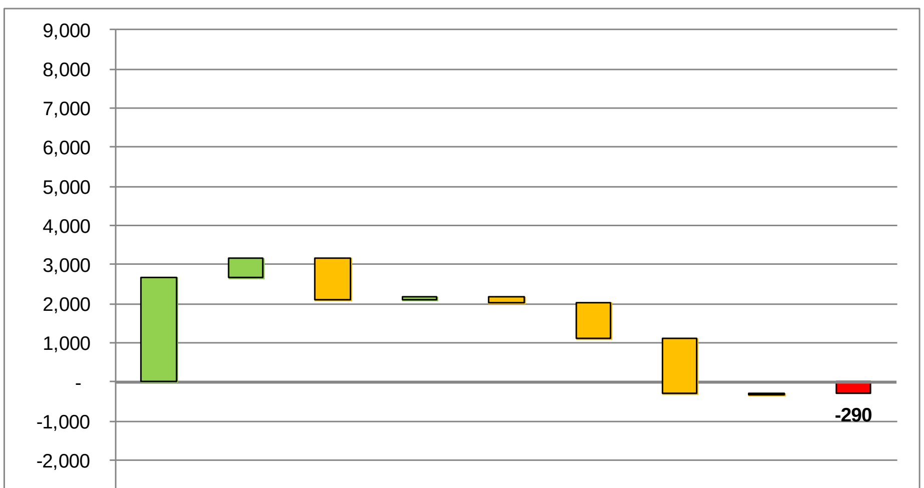
	Added Export	Fuel&PP Sav	Interest	Depreciation	O&M	Gov't Charges	Added to Reserves	FN Partners	Ratepayers
ends -									-419
before	-	2,548	2,959	1,941	2,037	1,878	986	-404	
after	2,548	2,959	1,941	2,037	1,878	986	-404	-419	

Figure 16: Year 40 - REF-REF-REF Plan 1 vs. Plan 14 (NPV $ Millions) at 10% Real Discount Rate



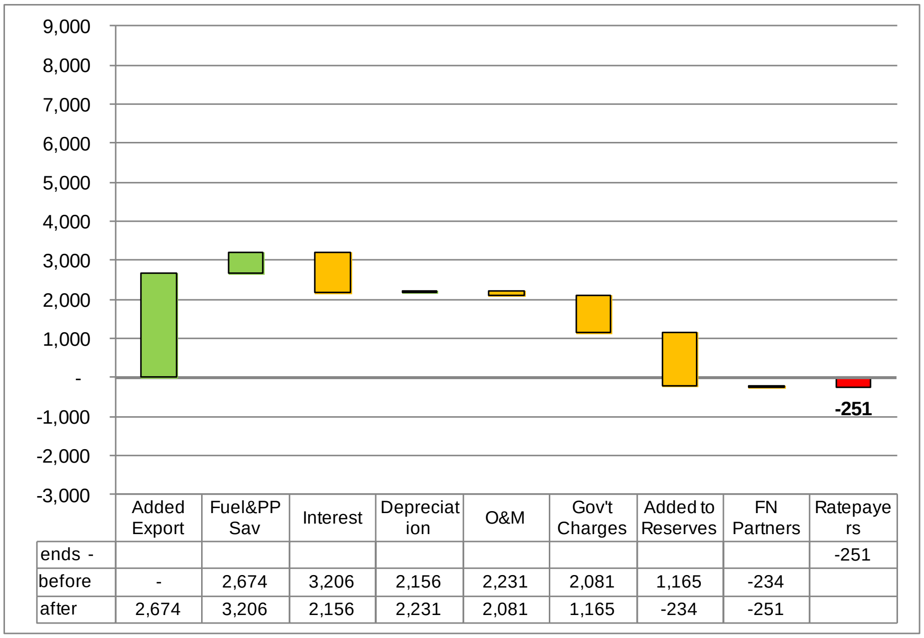
	Added Export	Fuel&PP Sav	Interest	Depreciation	O&M	Gov't Charges	Added to Reserves	FN Partners	Ratepayers
ends -									-344
before	-	2,611	3,083	2,043	2,127	1,973	1,067	-328	
after	2,611	3,083	2,043	2,127	1,973	1,067	-328	-344	

Figure 17: Year 45 - REF-REF-REF Plan 1 vs. Plan 14 (NPV $ Millions) at 10% Real Discount Rate



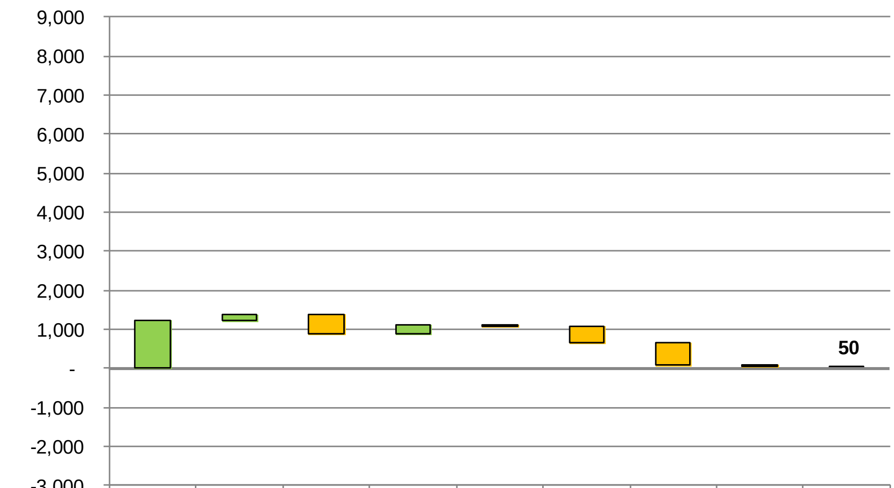
	Added Export	Fuel&PP Sav	Interest	Depreciation	O&M	Gov't Charges	Added to Reserves	FN Partners	Ratepayers
ends -									-290
before	-	2,650	3,159	2,111	2,189	2,037	1,124	-273	
after	2,650	3,159	2,111	2,189	2,037	1,124	-273	-290	

Figure 18: Year 50 - REF-REF-REF Plan 1 vs. Plan 14 (NPV $ Millions) at 10% Real Discount Rate



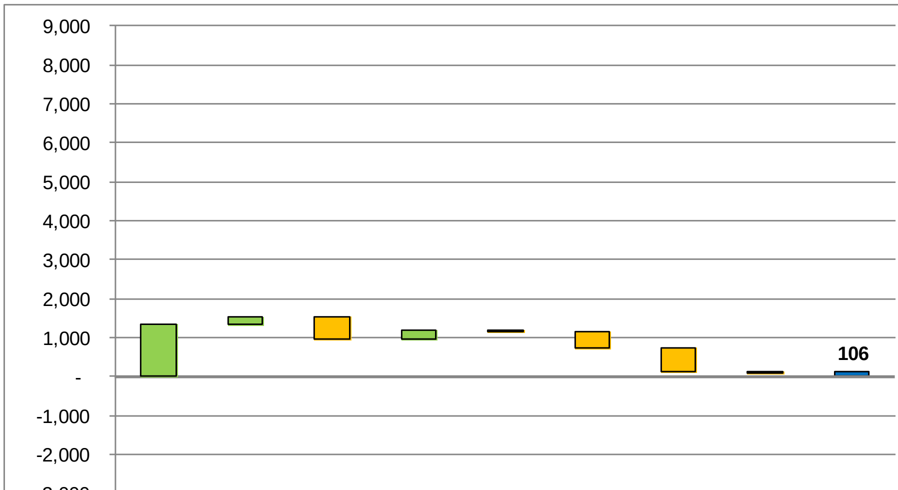
Figures 19 through 24 below show the waterfall graphs for Plan 4 (K19/Gas/250MW) as compared to Plan 1 (All Gas) for the scenario with Reference Economic Conditions, Reference Energy Prices and Reference Capital Costs at a real discount rate of 10% for the five year increments from Year 25 to Year 50 for the Financial Analysis.

Figure 19: Year 25 - REF-REF-REF Plan 1 vs. Plan 4 (NPV $ Millions) at 10% Real Discount Rate



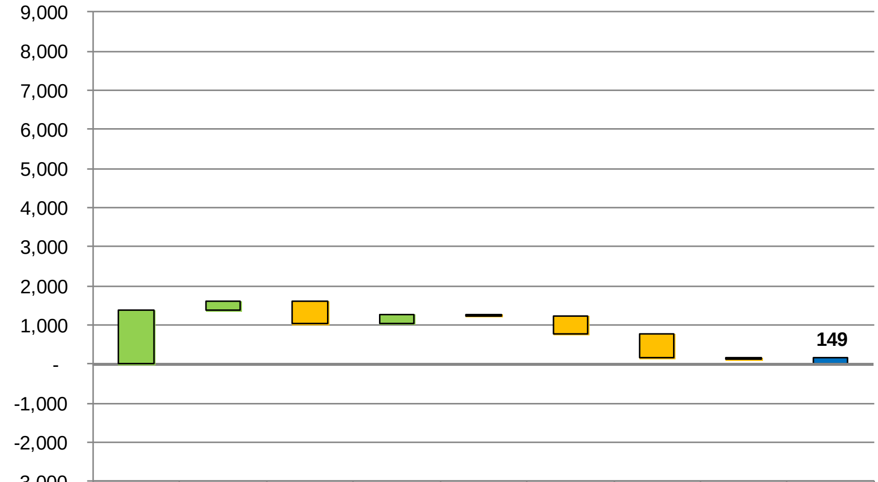
	Added Export	Fuel&PP Sav	Interest	Depreciation	O&M	Gov't Charges	Added to Reserves	FN Partners	Ratepayers
ends -									50
before	-	1,219	1,386	867	1,096	1,055	654	71	
after	1,219	1,386	867	1,096	1,055	654	71	50	

Figure 20: Year 30 - REF-REF-REF Plan 1 vs. Plan 4 (NPV $ Millions) at 10% Real Discount Rate



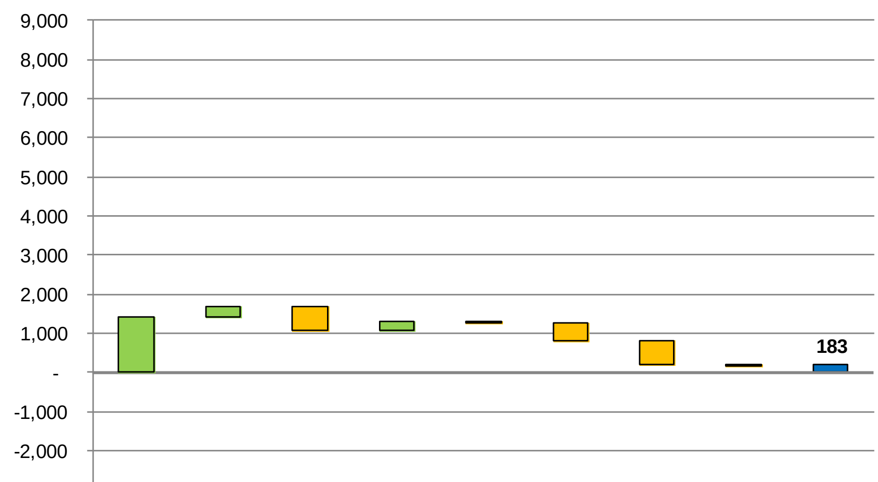
	Added Export	Fuel&PP Sav	Interest	Depreciation	O&M	Gov't Charges	Added to Reserves	FN Partners	Ratepayers
ends -									106
before	-	1,321	1,527	971	1,184	1,146	723	130	
after	1,321	1,527	971	1,184	1,146	723	130	106	

Figure 21: Year 35 - REF-REF-REF Plan 1 vs. Plan 4
(NPV $ Millions) at 10% Real Discount Rate



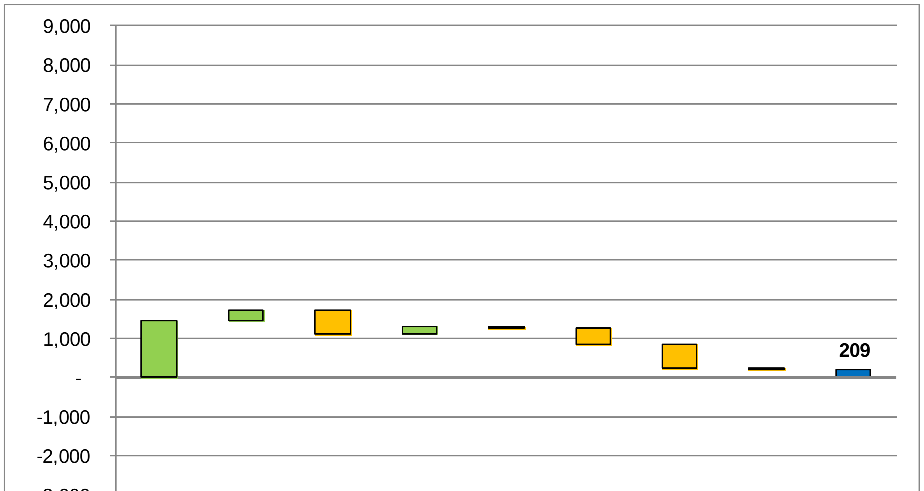
	Added Export	Fuel&PP Sav	Interest	Depreciation	O&M	Gov't Charges	Added to Reserves	FN Partners	Ratepayers
ends -									149
before	-	1,388	1,617	1,042	1,245	1,207	773	176	
after	1,388	1,617	1,042	1,245	1,207	773	176	149	

Figure 22: Year 40 - REF-REF-REF Plan 1 vs. Plan 4
(NPV $ Millions) at 10% Real Discount Rate



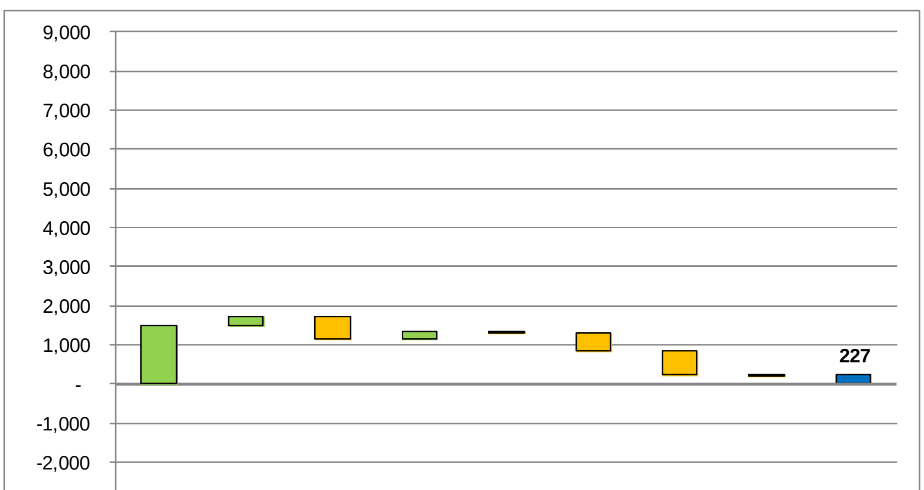
	Added Export	Fuel&PP Sav	Interest	Depreciation	O&M	Gov't Charges	Added to Reserves	FN Partners	Ratepayers
ends -									183
before	-	1,430	1,675	1,092	1,289	1,252	811	211	
after	1,430	1,675	1,092	1,289	1,252	811	211	183	

Figure 23: Year 45 - REF-REF-REF Plan 1 vs. Plan 4
(NPV $ Millions) at 10% Real Discount Rate



	Added Export	Fuel&PP Sav	Interest	Depreciation	O&M	Gov't Charges	Added to Reserves	FN Partners	Ratepayers
ends -									209
before	-	1,456	1,711	1,126	1,320	1,283	838	238	
after	1,456	1,711	1,126	1,320	1,283	838	238	209	

Figure 24: Year 50 - REF-REF-REF Plan 1 vs. Plan 4
(NPV $ Millions) at 10% Real Discount Rate



	Added Export	Fuel&PP Sav	Interest	Depreciation	O&M	Gov't Charges	Added to Reserves	FN Partners	Ratepayers
ends -									227
before	-	1,473	1,733	1,148	1,340	1,303	857	257	
after	1,473	1,733	1,148	1,340	1,303	857	257	227	

SUBJECT:

REFERENCE: MIPUG Report Page Appendix C Page C-47

PREAMBLE:

InterGroup speaks to the need to rebalance benefits received by Government and ratepayers under certain conditions.

QUESTION:

a) Please indicate under what economic conditions would a rebalancing of benefits be considered for each of plans 4, 6 and 14, and the time frame for such rebalancing with reasons.

b) Please indicate the degree of support and time frame that InterGroup believes is warranted if Plan 14 is pursued based on current known and forecast economic conditions.

ANSWER:

Note: Figure 35, filed on Page C-49 of Appendix C and the associated has been corrected since the initial filing of Mr. Bowman's Pre-Filed Evidence on February 5, 2014. Please see the revised version of Mr. Bowman's Pre-Filed Testimony.

(a) and **(b)**

Mr. Bowman's evidence does not presume any requirement for rebalancing of the benefits as between ratepayers and government if Plan 4 (K19/Gas/250MW) is pursued. While this plan entails risks for ratepayers with moderate benefits compared to Plan 1 (All Gas) (e.g., See Mr. Bowman's Appendix C, Figure 16 – the area of orange that is shown higher on the graph through year 40), while providing large returns with little associated risk for government with (Appendix C, Figure 25), some form of risk/benefit sharing arrangement would be beneficial. However, even in the event this is not forthcoming, Mr. Bowman's conclusion remains that advancing Keeyask to a 2019 in-service date and constructing a new transmission line to the United States is preferable to the base case, Plan 1 (All Gas).

Plan 6 (K19/Gas/750MW) is a more challenging situation. In this plan, the decision is made by June 2014 to pursue the 750 MW line at a higher cost than the 250 MW line, mostly for future option value (largely future ability to proceed with Conawapa if conditions permit). Ratepayers see a small additional cost impact from this decision and government sees a small increase in both cash revenues and overall benefits. Under present conditions, it is not clear the best way to deal with the added costs of the 750 MW line:

- Mr. Bowman's pre-filed testimony notes that the 750 MW line should likely be pursued even if ratepayers are absorbing the costs of the line in full.
- However, the decision to proceed with the 750 MW (and hence help open the option for Conawapa) would be considerably more balanced in an environment of revised risk and benefit sharing (similar to that noted for Plan 14 (PDP) below).

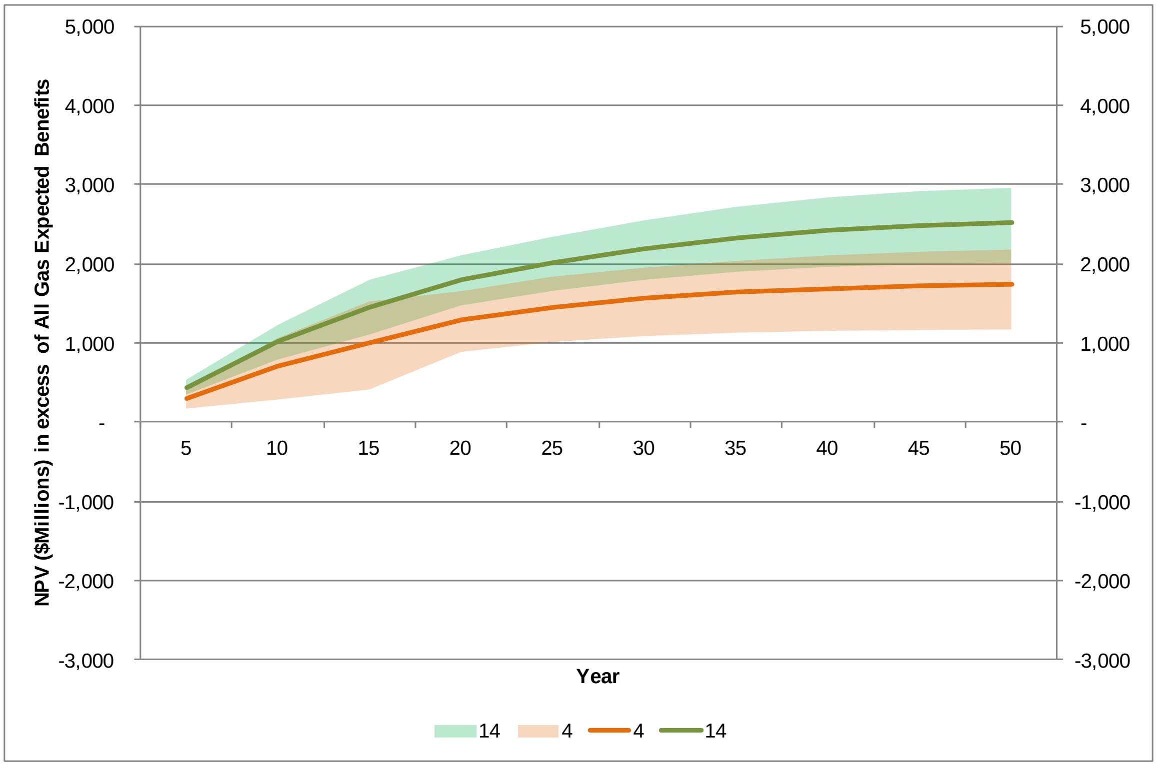
With respect to Plan 14 (PDP), under current economic and market conditions there is no likely basis for ratepayers to benefit from this plan without a substantial revised sharing arrangement. The degree and duration for sharing could vary. Mr. Bowman's pre-filed testimony sets out one example of how such a rebalancing could be considered[1] over approximately 15 years, but there are a wide range of alternative means available.

In practice, Mr. Bowman suggests that a decision could be made in the near-term to revise the sharing arrangements on all projects, and permit the 750 MW line to proceed. Activities over the next four years to 2018 would then be based on a clear knowledge of the sharing arrangements during the period, as studies on Conawapa are advanced, the economics are updated and an expanded range of export arrangements are pursued, all prior to a decision being made to proceed with Conawapa.

Under the one example of a possible benefit sharing arrangement provided in Mr. Bowman's Appendix C, the total government benefits remain above the levels that would be achieved under solely Plan 4 (K19/Gas/250MW) as shown in the following figure:

[1] Mr. Bowman's pre-filed testimony plots the ratepayer impacts assuming all government charges (debt guarantee, water rentals, capital tax) are waived on the major PDP projects (Keeyask, Conawapa, US Transmission) starting immediately and continuing on each respective project until it reaches its 15th year in service (2034 for US Transmission and Keeyask, 2040 for Conawapa).

Figure 1: Plan 4 vs. Plan 14 with Government Benefit Sharing Arrangement at 5.05% Real Discount Rate – NPV of Incremental Government Benefits as compared to Plan 1 Expected Value ($ Millions)



In particular, Figure 1 notes that even under the benefit sharing arrangement for Plan 14 (PDP), the government of Manitoba remains ahead of the benefits it would receive if only Plan 4 (K19/Gas/250MW) were pursued. The cash payments to the government would be lower than without the sharing arrangement, but the overall benefits, inclusive of growth in Shareholder Equity would well exceed Plan 4 (K19/Gas/250MW).

SUBJECT:

REFERENCE: MIPUG Report Page Appendix C Page C-49

PREAMBLE:

Intergroup states that Other scenarios would need to be assessed as part of decisions regarding whether to proceed with Conawapa.

QUESTION:

a) Please indicate what other scenarios would need to be assessed in supporting the decisions to proceed with Conawapa.

ANSWER:

(a)

The ‘Other scenarios’ that would need to be assessed refers to alternative means to generate a rebalanced relationship between (a) Hydro’s finances that are recovered from ratepayers and (b) value generated to the provincial government. This is needed if Plan 14 (PDP) is to be pursued under the currently expected economic and market conditions, as ratepayers are otherwise materially worse off with Plan 14 (PDP) than with other viable alternatives such as Plan 4 (K19/Gas/250MW).

Mr. Bowman has modeled one option to address this imbalance by foregoing all government charges on Hydro for the relevant projects over a pre-defined horizon on the order of 15 years. Other options could involve:

1) Alternatives that vary the set of charges to be foregone, while also varying the horizon over which the rebalancing occurs.

2) Alternatives that do not automatically forego the charges, but instead put in place a contingent payment regime (e.g., potentially more akin to the examples in MH/MIPUG I-3 with government provided flexible debt financing).

3) Alternatives that provide for a specified government backstopping of Hydro’s risk regime, in exchange for a lower Contribution to Reserves equivalent to a slower growth in Shareholder’s Equity. This could, for example, potentially permit the added projects of the Plan 14 (PDP) to be financed with less than 25% equity

until a much later phase of their existence. For example, at the time Limestone was brought into service Hydro did not have a debt:equity target and routinely operated with 95:5 debt:equity ratio, such that the early years of Limestone did not require a rate impact to quickly build up substantial equity, as is being proposed in this NFAT.

Each of these options would require additional discussion and modeling to determine a complement of measures that serves to achieve the noted rebalancing. Perfecting the model is not possible with the information made available to participants in the NFAT proceeding.

It is important to remain cognizant that under the current market and financial forecasts, if the relationship between costs to ratepayers and benefits to the Government cannot be rebalanced then Plan 14 (PDP) should not be the plan selected to proceed.

SUBJECT:

REFERENCE: MIPUG Report Page 1-10

PREAMBLE:

QUESTION:

a) Please explain why Hydro's approach to modeling DSM savings, as an adjustment to the load forecast rather than a competing resource, is more appropriate for this NFAT for testing between the various Pathways.

ANSWER:

(a)

Mr. Bowman is not suggesting that using DSM as an adjustment to the load forecast is "more" appropriate for this NFAT, just that it is an appropriate approach given the comparisons being undertaken.

Ideally, there would be the ability to model and compare many additional variables in the scenarios beyond just Interest Rate, Energy Prices and Capital Costs, and this could include Load Forecast and DSM levels. However, adding additional variables to the analysis exponentially complicates the calculations and work required, and in this case Mr. Bowman has concluded it is not absolutely necessary for a proper review of the NFAT. This is because Mr. Bowman has suggested that on the major decisions to be made, there are effectively two steps:

- Step 1 - there is a need to select between Need-Based plan (such as Plan 1 (All Gas)) and an Opportunity-Based plan (such as Plan 14 (PDP) or Plan 4 (K19/Gas/250MW)). This decision can be made by a range of factors. These factors include economics, but also such matters as risk aversion, concerns over corporate debt levels or consolidated provincial debt levels, and a desire to avoid decision-making on major plant investment until a later date. Mr. Bowman has noted that for this purpose, an optimized Plan 1 (All Gas) including varying levels of DSM could be instructive[1], but would not likely be determinative to the decision. This is because (a) the version of Plan 1 (All Gas) provided to date already has the key characteristics to assess a Need-

[1] For example, see Pre-filed testimony page 1-6 line 23 to page 1-7 line 2.

Based plan (e.g., less debt than Plan 14 (PDP)), and (b) it is not expected that an optimized Plan 1 with extreme DSM (4.0x or higher) would be materially more economic even if it includes wind, customer power purchases, etc. (see CAC/MIPUG I-8).

- Step 2 – within the Opportunity-Based approaches there is a need to select the plan or pathway that is optimal. Hydro's approach to modeling DSM savings, as an adjustment to the load forecast is appropriate for testing between Pathways #3, #4 and #5[2] because the key determinant in selecting between the various plans is not affected by selecting a different level of DSM, as described below. Of particular note, Hydro provides the sensitivity tests on higher levels of DSM at Chapter 12, summarized in Figures 12.5 and 12.6 (pages 19-21). The figures indicate that even if DSM can be achieved *at no cost*, the relative economic ranking and superiority of the different Opportunity-Based plans does not materially change regardless as to whether DSM is achieved at 1.0x forecast, 1.5x forecast, or even the extreme 4.0x forecast. The height of the blue bars (the NPV of benefits) changes to some degree, but not the preference for larger plans (e.g., Plan 14 (PDP)) over smaller plans (in this case Plan 2 (K23-30/Gas)[3]).

Mr. Bowman concludes in his Pre-Filed Testimony that given the information available, an Opportunity-based vision (advance Keeyask, take up Minnesota Power export deal, build new transmission to US) is likely better than a Needs-Based vision designed around Plan 1 (All Gas)[4]. For this reason, using DSM savings as an adjustment to load forecast rather than a competing resource is a reasonable approach for the NFAT.

[2] Recognizing, however, that Pathway #5 as it is portrayed in the NFAT Business Case is understood to be no longer possible in that particular form including WPS investment in transmission.
[3] Plan 2 is based on building Keeyask for the date when new supplies are needed. Depending on the level of DSM in this scenario, from 1.0x to 4.0x, the date when Keeyask is required changes from 2024 to 2030.
[4] Page 1-7 of Pre-Filed Testimony.