Exhibit CAC# 45-5

CAC Manitoba: Book of Documents
NFAT Review

Tab	Document
1	Public Utilities Board, Final Order with respect to Manitoba Hydrp's 2012/13 and 2013/14 General Rate Application: Order No. 43/13 p. 25-28
2	Public Utilities Board, NFAT, Response to Information Request *PUB/MH I-077a*
3	Manitoba Hydro, Submission to the Manitoba Clean Environment Commission: NFAT – The Wuskwatim Project, (April 2003) Chapter 7: p. 1, 2, 5, 7, 11, 12 Attachment 7 – Tables A.21, A.22
4	NFAT: Transcript of Proceedings – March 14, 2014 p. 2491, 2492
5	Manitoba Hydro, *20 Year Financial Outlook: 2009/10-2028/29* p. 2, 3, 5, 8-11
6	Manitoba Hydro, *Consolidated Integrated Financial Forecast (IFF12)* p. 4
7	Manitoba Hydro, NFAT Filing: *Appendix D – 2013 Electric Load Forecast* p. 44, 45
8	Public Utilities Board, NFAT, Response to Information Request *MH/CAC – Harper MH 23a*
9	Public Utilities Board, NFAT, Response to Information Request *MIPUG/MH I-003a* *MIPUG/MH I-003c* *MIPUG/MH I-004c* *MIPUG/MH II-005b*
10	Morrison Park Advisors, *Commercial Evaluation of Manitoba Hydro Preferred Development Plan Business Case* (January 2014) p. 16, 42, 43, 48, 67-69, 74 74, 94
11	David Burgess and Richard Zerbe, "Appropriate Discounting for Benefit-Cost Analysis" *Journal of Benefit-Cost Analysis*; Vol. 2; Iss. 2, Article 2. (2011)
12	David Burgess and Richard Zerbe, "The Most Appropriate Discount Rate" *Journal of Benefit-Cost Analysis. Volume* 4, Iss.3 (2013)
13	The Ontario Power Authority, EB-2007-0707, Exhibit D/Tab 3/Schedule 1/Attachment 1 p. 1-7

TAB 1

M A N I T O B A	**Order No. 43/13**
THE PUBLIC UTILITIES BOARD ACT	**April 26, 2013**

Before: Régis Gosselin, B.A., M.B.A., C.G.A., Chair
Raymond Lafond, B.A., C.M.A., F.C.A., Member
Larry Soldier, Member

FINAL ORDER WITH RESPECT TO
MANITOBA HYDRO'S 2012/13 AND 2013/14
<u>GENERAL RATE APPLICATION</u>

9.0.0 WUSKWATIM GENERATING STATION PROJECT

9.1.0 Issues

9.1.1 Cost Escalation

The Clean Environment Commission in 2003 conducted a hearing examining the Need For and Alternatives To the Wuskwatim project. The projected cost of the project at the Clean Environment Commission hearing was $901 million for the generating station and transmission facilities.

Since then, the capital cost estimate increased on an annual basis, almost doubling to $1,77 million.

9.1.2 Tendering Problems with Northern Generation

Manitoba Hydro experienced tendering difficulties with the primary contract(s) for building the generating station. This led to a retendering on a component basis. Productivity problems with respect to major civil, mechanical, and electrical components were also experienced.

9.1.3 The Wuskwatim Power Limited Partnership Agreement

The Wuskwatim Power Limited Partnership Agreement provided for a first-ever First Nations ownership stake in a Manitoba Hydro generating facility. Pursuant to the terms of the Agreement, the Nisichawayasihk Cree Nation was given the option of being a Limited Partner in the Wuskwatim Generating Station with an interest of up to 33%.

Revenues received by the Partnership from the sale of power to Manitoba Hydro were based on the actual output of Wuskwatim Generating Station and be priced in accordance with an agreed methodology which reflected Manitoba Hydro's actual selling prices for exports. The Partnership would pay Manitoba Hydro a percentage of gross revenues to contribute towards the marketing and transmission risks borne by Manitoba Hydro.

Wuskwatim's revenue related to energy generated during the on-peak (5x16) hours is determined based on the average price Manitoba Hydro realizes for long-term export sales and import transactions. Wuskwatim's revenue related to energy generated during the off-peak hours is determined from the average price Manitoba Hydro realizes for all on-peak and off-peak opportunity export and import transactions, excluding the on-peak long-term contract transactions. The total of gross revenue related to on-peak and off-peak energy is reduced by transmission and related market participation charges and Manitoba Hydro's 3% marketing risk fee. Domestic sales are not included in the determination of the revenue allocated to the Wuskwatim Power Limited Partnership.

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Because of low export prices, Manitoba Hydro is now forecasting losses for the first ten years of operations of Wuskwatim. Those losses are projected to total $341 million as Manitoba Hydro forecasts the project will not be profitable until 2023. The current agreement also requires the partners to invest more money to cover operating losses.

The total cost of Wuskwatim as identified by Manitoba Hydro (in Exhibit #108) was $1.77 billion. Manitoba Hydro only applied $1.25 billion of project costs to the Wuskwatim Power Limited Partnership, as it subtracted $526 million of Manitoba Hydro's internally generated funds. On this basis, there is a net cost to the partnership of $43 million in 2012/13 and $75 million in 2013/14. This net cost results from the apportionment of both project costs and export revenues to the Partnership, with low export revenues contributing to a shortfall in both years.

If Manitoba Hydro's attribution of internally generated funds is removed from the calculation of partnership costs, the shortfalls would increase to $68 million and $114 million in 2012/13 and 2013/14, respectively. Because internally generated funds are the result of ratepayer contributions, they constitute a real cost to ratepayers that cannot be ignored when assessing the total impact of the project. In the absence of the Partnership covering the shortfalls, these costs flow through to domestic ratepayers.

During the hearing, Manitoba Hydro indicated its intention to re-negotiate the Agreement with the Wuskwatim Power Limited Partnership. Manitoba Hydro provided a calculation that attributed revenues based on the average of domestic and export revenues rather than just export revenue, upon which the Wuskwatim Power Limited Partnership Agreement is currently based. That potential change would still leave the Partnership with a shortfall in both test years, albeit a reduced amount. However, in the absence of a recovery in export prices, the net impact on ratepayers would actually increase, as a portion of domestic revenue would now be allocated to the Partnership.

Wuskwatim Generating Station in average flow years adds about 1,500 GWh/yr to the existing 29,500 GWh of energy, for a total Manitoba Hydro energy capability of 31,000 GWh. With average annual domestic load and firm export contract commitments less than 29,000 GWh until 2020, Wuskwatim energy is forecast to be sold at prices in the range of 3.0-3.5¢/kWh.

Wuskwatim Generation came on-line in 2012/13 with a Board-calculated (all-in) incremental in-service cost of $160 million/yr (10.5¢/kWh). This is about three times the current average export revenue rate (for both firm and spot market sales) of about 3.2¢/kWh.

The Consumers' Association of Canada (Manitoba) Inc. did not object to the renegotiation of the Wuskwatim Power Limited Partnership agreement. However, it expressed great concerns about the Wuskwatim project's cost growth. It further questioned whether the full impact of the Wuskwatim losses should be borne by current

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ratepayers, as the extent of the losses were not contemplated when the project was initiated.

9.2.0 Board Findings

The Board has difficulty rationalizing the increase in the cost of the Wuskwatim project from the $900 million estimate presented to the Clean Environment Commission in 2003, to the most recent estimate of a $1.77 billion in-service cost. The increase in costs, in conjunction with a substantial decrease in export prices, means that the anticipated results have not been achieved and will not be achieved for many years.

The capital cost escalation of the Wuskwatim project is of serious concern to the Board. The reasons for the increased costs need to be more specifically broken down with respect to the various project components and construction activities. The utility's northern generation projects experienced competing demands for skilled labour from the Alberta market, resulting in the need to hire unskilled labour that had to be trained locally. This resulted in overall low productivity. These concerns should be more fully addressed and mitigated in future northern capital projects to the extent possible.

The Board understands that Manitoba Hydro is currently renegotiating its Wuskwatim Power Limited Partnership Agreement with its First Nations Partner as the economics of the project have changed substantially since the time the Agreement was first concluded. The revenues to be attributed to the Wuskwatim Power Limited Partnership were to be based on export revenues. The Wuskwatim Power Limited Partnership financial forecast now projects many years of losses. Absent adequate export revenues, the losses now have to be funded by domestic ratepayers. The Board expects to be notified when any changes to the current Agreement are finalized and apprised of the impact of such changes on Manitoba Hydro's operating results and domestic rates.

As for the cost consequences of Wuskwatim on Manitoba Hydro, the current rate increase requests are required to meet the operating losses from Wuskwatim. The Board finds that, as a rule-of-thumb, the average incremental annual operating cost of a capital project can be approximated at 9% of the capital cost minus the incremental export revenue gained. This makes for an additional revenue requirement of the Wuskwatim project viewed in isolation (without internally generated funds) equivalent to about $100 million in 2012/13 and $160 million in 2013/14. These costs are significantly greater than the $74 million and $117 million (respectively) set out in Information Request CAC/MH I-15(a) where Manitoba Hydro used financial costs that were net of internally generated funds:

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	Partial Year 2012/13	2013/14
9% of $1.77B Capital Cost	$100M	$160M
Average Output/year	900 GWh	1520 GWh
Unit Output Cost	10.0 ¢/kWh	10.5 ¢/kWh
Incremental Revenues	$26M	$43M
Average Net Export Revenue Rate*	2.8 ¢/kWh	2.8 ¢/kWh
Net Cost Impact on Rate Payers**	**$74M**	**$117M**

*While MH calculates its total Export Sales (including long term firm export contract) average price of approximately 3.2 ¢/kWh [Exhibit MH-17], the output of Wuskwatim is not committed to a long term firm Export contract, so the average price of Wuskwatim output is only 2.8 ¢/kWh. [Exhibits MH-11 and MH-34]

**This assumes no new firm export contracts for Wuskwatim output.

The Board also understands that Manitoba Hydro intends to allocate only $1.25 billion of capital cost to the Wuskwatim Power Limited Partnership, employing $526 million of Manitoba Hydro's internally generated funds (accumulated since 2003). This would result in net costs to the Wuskwatim Power Limited Partnership of $43 million (2012/13) and $75 million (2013/14), assuming Manitoba Hydro ratepayers have already invested approximately $500 million that could have been utilized to reduce its overall level of borrowing.

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TAB 2

REFERENCE: Chapter 11: Financial Evaluation of Development Plans; PUB/MH I-134, 2012 GRA

QUESTION:

Please file the response to PUB/MH I-134 from the 2012 GRA.

RESPONSE:

In Order 119/13 the PUB ordered that Manitoba Hydro may respond to this Information Request by filing existing information without providing the requested update.

Please see the attached response to PUB/MH I-134 from the 2012 GRA.

WUSKWATIM POWER LIMITED PARTNERSHIP (IFF11-2)
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
REVENUES											
Revenue	1	57	57	69	90	99	108	117	124	125	133
	1	57	57	69	90	99	108	117	124	125	133
EXPENSES											
Operating and Administrative	1	10	10	10	10	10	10	10	10	11	11
Finance Expense	3	62	71	73	75	74	73	72	70	68	66
Depreciation and Amortization	1	23	25	25	25	25	25	25	25	25	25
Water Rentals and Assessments	0	5	5	5	5	5	5	5	5	5	5
	5	99	110	113	115	114	113	112	110	109	106
Net Income	(3)	(42)	(54)	(44)	(25)	(15)	(5)	5	14	17	27
Financial Ratios											
Debt	75%	78%	82%	85%	85%	85%	85%	84%	83%	81%	75%

TAB 3

SUBMISSION TO THE MANITOBA CLEAN ENVIRONMENT COMMISSION:

NEED FOR AND ALTERNATIVES TO THE WUSKWATIM PROJECT

7.0 FINANCIAL ANALYSIS

7.0 Introduction

The financial analysis uses the revenue and cost assumptions in the economic analysis, described in the previous chapter, to generate projected financial statements for 1) the Wuskwatim Partnership and 2) Manitoba Hydro, reflecting the business arrangements negotiated with the Nisichawayasihk Cree Nation. The economic analysis has determined that the advancement of the Wuskwatim Project would provide an attractive rate of return over the life of the project. The purpose of the financial analysis is to ascertain whether the advancement of Wuskwatim Project would adversely affect Manitoba Hydro's financial stability during the start-up years and to determine the degree to which the economic benefits could ultimately translate into domestic customer rate savings.

7.1 Partnership Financial Arrangements

The Nisichawayasihk Cree Nation has the option of being a Limited Partner in the Wuskwatim G.S. with an interest of up to 33%. Manitoba Hydro, through a holding company as General Partner, would have a 0.01% interest, with Manitoba Hydro as a Limited Partner holding the balance.

The assets of the Partnership would consist of the Wuskwatim G.S. and, to the degree required, a small amount of working capital. The capital cost would include planning studies, engineering and licensing from April 1, 2002 plus the unamortized balance of prior expenditures. Accounting policies would mirror those of Manitoba Hydro.

Revenues received by the Partnership from the sale of power to Manitoba Hydro would be based on the actual output of Wuskwatim G.S. and be priced in accordance with an agreed methodology which reflects Manitoba Hydro's actual selling prices for exports. The Partnership would pay Manitoba Hydro a percentage of gross revenues to contribute towards the marketing and transmission risks borne by the Corporation.

A Transmission charge would be levied which recovers the depreciation, interest, maintenance and operating costs associated with the incremental facilities specifically required to serve Wuskwatim G.S. An additional charge would be included for any facilities that Manitoba Hydro requires for its other system needs but is advancing in order to accommodate the Wuskwatim G.S. This extra cost recovery would only be for the period of advancement.

The Partnership structure is intended to maintain each partner's current income tax status. Any taxes which are nonetheless required to be paid by one partner would be borne exclusively by that partner and would not be an expenditure of the Partnership itself.

For the purposes of the projections, and consistent with Manitoba Hydro's Integrated Financial Forecast (**Appendix 9**), water rental rates are assumed to continue at current levels. As in the economic analysis, annual operating cost estimates are based on a long run average which includes some provision for minor capital maintenance. Larger periodic scheduled capital expenditures are assumed to generally fall outside of the study period which extends to 2034/35. It is expected that the partnership will accumulate a reserve to fund these larger capital expenditures in the future. The administrative costs of the Partnership would be charged on an actual basis, assumed for purposes of this analysis to be $0.5 million per year, escalated at the rate of inflation.

The capital structure of the partnership will be 75% debt /25% equity, except for the first ten years of the project when the debt ratio may be allowed to temporarily rise to as much as 85% in order to accommodate any front-end losses. Cash calls would be made on the Partners, if required, to ensure that the debt ratio does not exceed the prescribed limits.

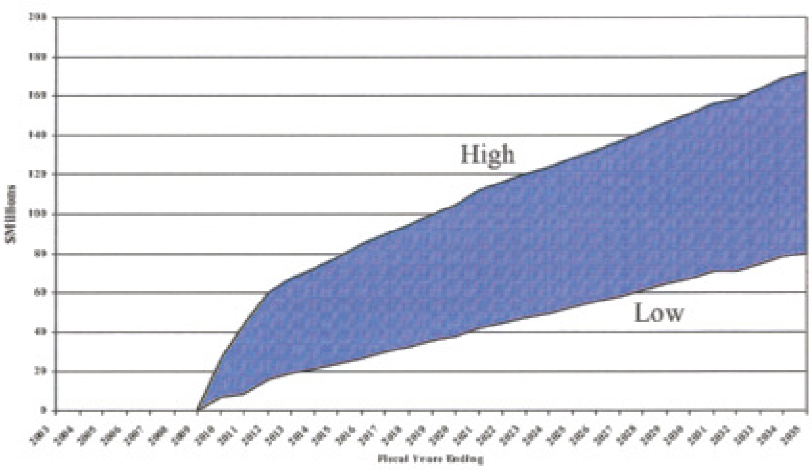
The evaluation compares the year-by-year financial impacts of the advancement of the Wuskwatim G.S. to an in-service date of 2009, including the associated Partnership with the Nisichawayasihk Cree Nation. The 2009/10 case, in which Wuskwatim Project is advanced for export sales opportunities, is compared to a base case in which Manitoba Hydro constructs the same generating station in 2020/21 as dictated by domestic load requirements under the same Partnership terms and conditions. Since the gas operations of Manitoba Hydro are not affected by the timing of the Wuskwatim Project and the gas business has a small impact on Manitoba Hydro's overall financial position, the analysis is limited to the effects of the Wuskwatim Project on Manitoba Hydro's electricity operations rather than on the Corporation's full consolidated financial results.

The 2020/21 base case is an extended and partially updated version of the fall 2002 Integrated Financial Forecast, IFF02-1 (**Appendix 9**). Annual projected rate increases for the base case sequence are identical to those in IFF02-1 until 2012/13. Beyond this period, rate increases are modelled by maintaining an annual target interest coverage of 1.15. Consistent adherence to this target at times produces rate increases that exceed the rate of inflation while in other years it requires rate reductions. In practice, rate changes would be approved by the Public Utilities Board prior to implementation and would tend to be smoothed over a period of years. Application of rate smoothing to the 2020/21 base case would result in average rate increases at or below the projected rate of inflation. This reinforces the reasonableness of selecting the target average interest coverage of 1.15 in developing a base case.

Comparison of the 2009/10 and 2020/21 financial projections tests whether Manitoba Hydro can afford to absorb the up-front costs of the Wuskwatim Project and related business arrangements without negatively affecting the Corporation's financial stability or incurring incremental rate increases for domestic customers. Beyond the startup period, two types of analysis are undertaken: 1) to quantify the incremental impact on net income and interest coverage and 2) to translate these anticipated benefits into longer-term customer rate savings. To accomplish the latter, the Wuskwatim 2009/10 case is behalf of the Project and advanced to the Partnership on a cost-recovery basis, including a provision for the provincial debt guarantee fee.

Maintenance of a 75% debt ratio assumes that dividends could be paid to the Partners beginning in 2009/10 at levels that slightly exceed annual net income. Under all export price scenarios examined in the analysis, positive net income is projected for the Partnership in every year from the date of in-service. Profitability climbs steadily over the forecast period as projected export prices rise in both real and nominal terms. The Wuskwatim G.S. partnership dividends for the various export price cases are shown in **Figure 7.1**. Dividends by 2035 range from \$80 million to \$172 million.

Figure 7.1
Wuskwatim Partnership Dividends
2009 In-Service



7.2.2 Projected Manitoba Hydro Financial Results Including Partnership

Due to the Nisichawayasihk Cree Nation's minority 33% ownership of the equity of the Wuskwatim G.S. partnership, it is expected that Manitoba Hydro's financial statements will consolidate the Partnership on a non-controlling interest

Attachment 7 Tables A.20 to A.24 show the projected financial statements for Manitoba Hydro's electricity operations under the Low and High export price scenarios for each of Wuskwatim G.S. in-service dates of 2009 and 2020 respectively. They provide further detail on the impacts illustrated in **Figures 7.2** to **7.4**.

The potential cumulative percent customer rate benefits and present value of customer bill benefits are shown in **Figure 7.5** and **Figure 7.6**. Customer rate savings would be possible immediately upon the achievement of the debt/equity ratio crossover point. As shown in **Figure 7.4**, this is projected to occur in 2015 to 2018, depending on the export price scenario. With the positive impacts on net income and interest coverage beginning prior to that point, substantially lower rates are needed to meet a 1.15 interest coverage ratio in subsequent years. In the Wuskwatim 2009 case, rates could be as much as 4% to 8% lower than with a 2020 in-service, and 2%-3% lower over the long term.

Figure 7.5
Impacts of Wuskwatim Advancement on Customer Rates

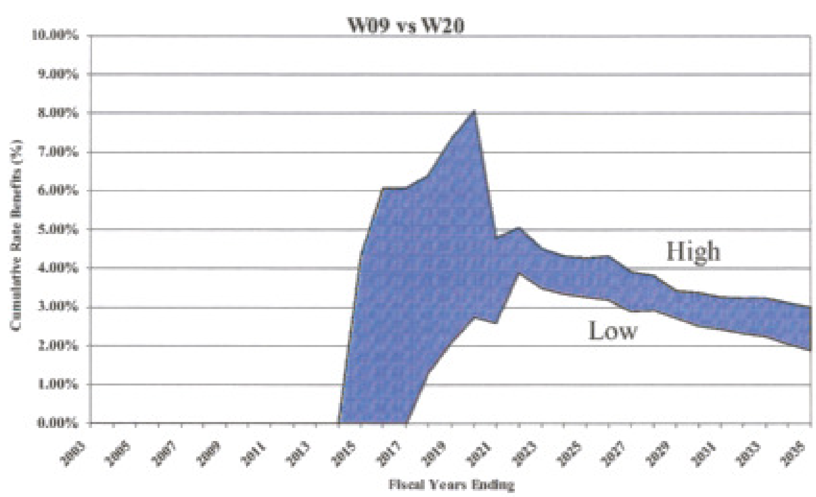


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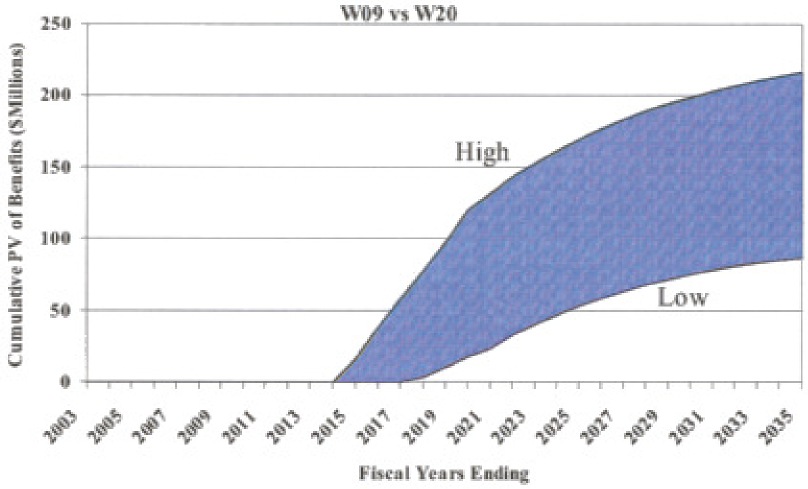
Figure 7.6
Impacts of Wuskwatim Advancement on Customer Bills



The decline in rate benefits after 2020 reflects the fact that the two sequences are identical in real terms after this point with the same export revenues and operating costs. The only difference after 2020 is that the 2009 Wuskwatim Project has a lower book value and associated carrying costs and that export revenues rather than domestic rate increases cover the Project start-up costs. On a present value basis discounted back to 2002, the advancement of the Wuskwatim Project to 2009 could yield a cumulative reduction in customers' electricity bills by $87 to $216 million to the end of the study period depending upon the export price scenario. The expected value for the cumulative decrease in customer bills, relative to the Wuskwatim 2020 case, is $143 million by 2035, with further potential benefits beyond that point.

Wuskwatim 2009 Low Price Scenario

ATTACHMENT 7 Table: A.21

PROJECTED OPERATING STATEMENT
Electric Operations
(In Millions of Dollars)

For year ending March 31:	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
REVENUES:																	
General Consumers Revenue																	
at approved rates	835	880	886	893	901	909	916	924	933	943	952	962	970	978	986	994	1,003
additional *	0	0	18	36	55	75	95	117	139	162	186	190	193	182	208	208	202
Winnipeg Hydro	21	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Extraprovincial	462	520	491	478	483	472	482	537	570	581	577	575	577	599	588	596	580
Other	6	7	7	6	6	6	6	5	5	3	2	1	0	(1)	(1)	(2)	(3)
	1,323	1,406	1,401	1,413	1,446	1,461	1,499	1,582	1,646	1,688	1,716	1,728	1,740	1,759	1,781	1,797	1,782
EXPENSES:																	
Finance Expense	477	513	530	541	549	559	557	592	620	627	618	617	606	603	608	615	586
Depreciation	256	270	282	301	310	324	331	350	363	372	381	390	396	394	402	410	420
Operating & Administrative	283	303	304	307	313	319	326	335	343	350	357	364	372	379	387	394	402
Water Rentals	106	106	103	103	102	102	102	106	107	107	107	107	107	107	107	108	107
Tax Expense	41	43	45	46	48	50	51	52	52	52	51	52	53	54	55	56	57
Fuel & Power Purchased	90	103	93	80	83	87	95	97	98	102	107	111	116	118	117	115	114
	1,252	1,339	1,357	1,378	1,405	1,442	1,463	1,531	1,582	1,610	1,621	1,641	1,651	1,655	1,676	1,698	1,685
Net Income (Loss)	71	68	45	35	40	19	37	51	64	78	95	87	89	104	105	99	96
*Additional General Consumers Revenue																	
Revenue			18	36	55	75	95	117	139	162	186	190	193	182	208	208	202
Percent Increase			2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	0.2%	0.1%	-1.1%	2.1%	-0.2%	-0.6%
Cumulative Pct Inc.			2.0%	4.0%	6.1%	8.2%	10.4%	12.6%	14.9%	17.2%	19.5%	19.8%	19.9%	18.6%	21.1%	20.9%	20.2%
Financial Ratios																	
Debt:Equity	79:21	79:21	80:20	80:20	81:19	81:19	82:18	81:19	81:19	80:20	78:22	78:22	77:23	77:23	76:24	76:24	76:24
Interest Coverage	1.14	1.12	1.08	1.06	1.07	1.03	1.06	1.08	1.10	1.12	1.15	1.14	1.14	1.16	1.16	1.15	1.15
Capital Expend Coverage	0.82	0.75	1.19	1.16	1.24	1.24	1.26	1.25	1.37	1.42	1.56	0.89	0.88	0.85	0.83	0.86	0.93

ATTACHMENT 7 Table A.21 (cont'd)

Wuskwatim 2009 Low Price Scenario

PROJECTED OPERATING STATEMENT
Electric Operations
(In Millions of Dollars)

For year ending March 31:	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
REVENUES:																
General Consumers Revenue																
at approved rates	1,011	1,020	1,029	1,039	1,051	1,063	1,075	1,086	1,097	1,109	1,119	1,130	1,141	1,152	1,163	1,173
additional *	222	246	248	249	276	375	381	390	398	403	413	418	400	415	431	458
Winnipeg Hydro	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Extraprovincial	535	514	508	508	602	726	762	751	746	746	742	737	733	728	722	743
Other	(4)	(5)	(6)	(6)	(7)	(8)	(8)	(9)	(10)	(11)	(12)	(13)	(13)	(14)	(15)	(15)
	1,765	1,774	1,779	1,790	1,922	2,156	2,210	2,217	2,231	2,247	2,262	2,272	2,261	2,281	2,302	2,359
EXPENSES:																
Finance Expense	567	558	536	514	581	763	804	794	789	785	780	770	741	739	737	748
Depreciation	427	437	446	456	491	538	540	547	555	562	570	579	587	596	605	623
Operating & Administrative	409	417	425	433	447	455	463	472	480	489	498	506	515	524	533	543
Water Rentals	108	107	107	108	112	120	122	122	122	122	122	122	122	122	122	122
Tax Expense	59	62	66	70	74	75	75	75	75	75	75	75	76	77	77	77
Fuel & Power Purchased	98	90	93	95	95	80	81	85	88	91	95	99	103	106	110	129
	1,668	1,673	1,672	1,676	1,800	2,031	2,085	2,094	2,109	2,125	2,141	2,152	2,144	2,164	2,184	2,242
Net Income (Loss)	97	102	107	113	122	125	125	123	123	122	122	120	116	117	118	117
*Additional General Consumers Revenue																
Revenue	222	246	248	249	276	375	381	390	398	403	413	418	400	415	431	458
Percent Increase	1.5%	1.7%		-0.1%	1.9%	7.1%	0.2%	0.3%	0.3%	0.1%	0.4%		-1.4%	0.7%	0.8%	1.4%
Cumulative Pct Inc.	22.0%	24.1%	24.1%	23.9%	26.3%	35.2%	35.5%	35.9%	36.3%	36.4%	36.9%	37.0%	35.0%	36.0%	37.1%	39.0%
Financial Ratios																
Debt:Equity	76:24	77:23	77:23	78:22	79:21	78:22	77:23	77:23	76:24	75:25	75:25	74:26	74:26	73:27	73:27	72:28
Interest Coverage	1.15	1.15	1.15	1.15	1.15	1.15	1.15	1.15	1.15	1.15	1.15	1.15	1.15	1.15	1.15	1.15
Capital Expend Coverage	0.96	1.00	1.05	1.13	1.25	1.42	1.24	1.22	1.18	1.16	1.14	1.12	1.09	1.06	1.04	1.03

Wuskwatim 2020 Low Price Scenario

ATTACHMENT 7 Table: A.22

PROJECTED OPERATING STATEMENT
Electric Operations
(In Millions of Dollars)

For year ending March 31:	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
REVENUES:																	
General Consumers Revenue																	
at approved rates	835	880	886	893	901	909	916	924	933	943	952	962	970	978	986	994	1,003
additional *	0	0	18	36	55	75	95	117	139	162	186	190	193	182	208	221	223
Winnipeg Hydro	21	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Extraprovincial	462	520	491	478	483	472	482	487	504	504	503	498	497	517	503	511	489
Other	6	7	7	6	6	6	6	6	7	7	7	7	7	7	8	8	8
	1,323	1,406	1,401	1,413	1,446	1,461	1,499	1,533	1,582	1,615	1,649	1,657	1,667	1,685	1,705	1,734	1,723
EXPENSES:																	
Finance Expense	477	513	531	548	554	562	560	557	561	573	566	562	552	558	559	569	542
Depreciation	256	270	287	307	316	330	337	345	354	364	374	375	382	380	387	396	405
Operating & Administrative	283	303	304	307	313	319	326	332	340	347	353	360	368	376	383	390	398
Water Rentals	106	106	103	103	102	102	102	102	102	102	102	102	102	102	102	103	103
Tax Expense	41	43	44	45	46	47	47	47	48	48	47	48	49	51	53	55	57
Fuel & Power Purchased	90	103	93	80	83	87	95	102	107	112	118	122	125	128	128	124	122
	1,252	1,338	1,364	1,389	1,414	1,447	1,467	1,485	1,511	1,545	1,561	1,569	1,579	1,595	1,611	1,636	1,626
Net Income (Loss)	71	68	38	24	32	14	33	48	70	70	87	88	88	90	93	97	97
*Additional General Consumers Revenue																	
Revenue			18	36	55	75	95	117	139	162	186	190	193	182	208	221	223
Percent Increase			2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	0.2%	0.1%	-1.1%	2.1%	0.9%	0.1%
Cumulative Pct Inc.			2.0%	4.0%	6.1%	8.2%	10.4%	12.6%	14.9%	17.2%	19.5%	19.8%	19.9%	18.6%	21.1%	22.2%	22.3%
Financial Ratios																	
Debt:Equity	79:21	79:21	80:20	80:20	80:20	80:20	80:20	80:20	79:21	78:22	77:23	76:24	76:24	76:24	76:24	76:24	77:23
Interest Coverage	1.14	1.13	1.07	1.04	1.05	1.02	1.05	1.08	1.12	1.12	1.15	1.15	1.15	1.15	1.15	1.15	1.15
Capital Expend Coverage	0.82	0.76	0.75	0.81	0.86	0.83	0.94	1.07	1.34	1.32	1.45	0.81	0.79	1.26	1.03	1.10	1.21

ATTACHMENT 7 Table: A.22 (cont'd)

Wuskwatim 2020 Low Price Scenario

PROJECTED OPERATING STATEMENT
Electric Operations
(In Millions of Dollars)

For year ending March 31:	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
REVENUES:																
General Consumers Revenue																
at approved rates	1,011	1,020	1,029	1,039	1,051	1,063	1,075	1,086	1,097	1,109	1,119	1,130	1,141	1,152	1,163	1,173
additional *	250	272	288	285	312	409	416	421	430	434	441	445	426	440	455	480
Winnipeg Hydro	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Extraprovincial	440	487	506	508	602	726	762	751	746	746	742	737	733	728	722	743
Other	8	4	3	3	2	1	1	0	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	1,709	1,782	1,826	1,835	1,966	2,200	2,253	2,257	2,272	2,286	2,299	2,308	2,295	2,314	2,333	2,389
EXPENSES:																
Finance Expense	523	560	571	548	613	796	836	823	819	813	807	796	765	762	759	769
Depreciation	413	435	450	460	496	542	544	551	559	567	574	583	592	600	609	627
Operating & Administrative	405	417	425	433	447	455	463	472	481	489	498	507	516	524	533	543
Water Rentals	103	106	107	108	112	120	122	122	122	122	122	122	122	122	122	122
Tax Expense	61	65	68	73	76	77	77	77	77	77	77	77	78	78	78	78
Fuel & Power Purchased	104	92	93	95	95	80	81	85	88	91	95	99	103	106	110	129
	1,609	1,675	1,714	1,716	1,840	2,070	2,123	2,130	2,145	2,160	2,173	2,184	2,175	2,194	2,212	2,269
Net Income (Loss)	100	107	112	118	127	130	130	128	127	126	126	124	120	121	121	120
*Additional General Consumers Revenue																
Revenue	250	272	288	285	312	409	416	421	430	434	441	445	426	440	455	480
Percent Increase	2.0%	1.5%	1.0%	-0.4%	1.8%	6.8%	0.1%	0.1%	0.3%		0.2%		-1.5%	0.7%	0.7%	1.2%
Cumulative Pct Inc.	24.7%	26.7%	27.9%	27.4%	29.7%	38.5%	38.7%	38.8%	39.2%	39.1%	39.4%	39.4%	37.4%	38.2%	39.2%	40.9%
Financial Ratios																
Debt:Equity	77:23	78:22	79:21	79:21	80:20	79:21	78:22	78:22	77:23	76:24	76:24	75:25	75:25	74:26	74:26	73:27
Interest Coverage	1.15	1.15	1.15	1.15	1.15	1.15	1.15	1.15	1.15	1.15	1.15	1.15	1.15	1.15	1.15	1.15
Capital Expend Coverage	1.15	1.09	1.02	1.10	1.21	1.38	1.21	1.19	1.18	1.16	1.14	1.12	1.10	1.08	1.06	1.06

TAB 4

just the expected value, but you're right, we didn't go as far to assess a -- a risk preference function and apply that.

THE CHAIRPERSON: Just an observation that while -- while corporately, Manitoba Hydro has addressed the downside risk, you know, the -- the plan did not work out as expected, and -- and you've invested significant dollars and -- and we're into a negative present -- net present value scenario.

The reality is, the base reference case from a ratepayer perspective is three point nine-five (3.95) per year for the next twenty-one (21) years. That's the base case. If it goes south, we're into a zone where it's much more than three point nine-five (3.95) per year.

So part -- I think part of what we need to think about is What's the risk to the ratepayer? Manitoba Hydro may be able to -- be able to cope with it, but that suggests to me that the ratepayer has got to be the one bearing the load.

MR. ED WOJCZYNSKI: I agree 100 percent with you. The -- the thing I would add to that, when I talked about mitigating the risk by, for instance, deferring Conawapa, that would also reduce the impact on -- on the ratepayer as well. So I wasn't just

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thinking of Manitoba Hydro's risk being mitigated, I was also thinking about the ratepayer risk being mitigated.

THE CHAIRPERSON: M. Monnin, s'il vous plait?

MR. CHRISTIAN MONNIN: Merci, Messr. President.

CONTINUED BY MR. CHRISTIAN MONNIN:

MR. CHRISTIAN MONNIN: I'd like to use a line from My Friend Mr. Williams, I just have a few more short questions. Regretfully, these -- these next pages are not in our book of documents. They can be found in Manitoba Hydro Exhibit 85, and if I've done this correctly this morning, I'm looking at page 177 of 192 should be where I would like to drive everyone's attention.

(BRIEF PAUSE)

MR. ED WOJCZYNSKI: Pardon me, which page was that again, please?

MR. CHRISTIAN MONNIN: It should be one seventy-seven (177) of the -- of -- of Manitoba Hydro-85. If you're looking at the Navigant report, if

TAB 5

Manitoba Hydro

20 YEAR FINANCIAL OUTLOOK

2009/10 – 2028/29

FINANCIAL PLANNING
CONTROLLER DIVISION
FINANCE & ADMINISTRATION

January, 2010

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OVERVIEW

The 20 Year Financial Outlook is an extension to the Integrated Financial Forecast IFF09-1 which was approved by the Manitoba Hydro-Electric Board on November 19, 2009. The 20 Year Financial Outlook depicts the long-term financial direction of Manitoba Hydro based on current assumptions of future events.

The first decade of the 20 Year Financial Outlook (the decade of investment) shows the financial impacts of major investments in new generation and transmission. Financial ratios are projected to weaken slightly in the first decade but rebound strongly in the second decade (the decade of returns). Domestic rate increases are projected to range from 2.9% to 3.5% per year in the first decade, then drop to 2.0% per year for the entire second decade. Equity (retained earnings) is projected to remain strong throughout the period, rising from $2.2 billion at March 31, 2010 to $11.2 billion at the end of 20 years. Drought remains one of the major risks with a repeat of the worst 5 year drought on record projected to cost $2.4 billion (assuming drought commencing in 2011/12).

KEY ASSUMPTIONS

The key assumptions included in the 20 Year Financial Outlook reflect similar assumption as the 11 year IFF and include the following:

1) Domestic Load Growth

   Domestic electricity load will grow at an average of 1.5% per year for net firm energy to 2019/20 and then 1.3% per year to 2028/29. Net total peak demand grows at an average of 1.3% per year over the 20 Year Financial Outlook to 2028/29.

   Natural gas volumes are projected to decline approximately 0.2% per year over the 20 Year Financial Outlook to 2028/29.

2) Domestic Rate Increases

   Average electricity rate increases of 2.9% per year are projected in 2010/11 and 2011/12 followed by 3.5% per year to 2019/20. Average electricity rate increases then drop to 2%, consistent with long-term projected inflation, for the last 9 years of the 20 Year Financial Outlook.

   Natural gas rate increases are projected to be only the rates necessary to generate net income of approximately $3 to $6 million per year (rate increases average less than 1% per year).

3) Inflation

The Manitoba Consumers Price Index is projected to increase at an average 2% per year commencing in 2011/12.

4) Interest Rates

The very low current short and long-term interest rates are projected to rise over the next 12 to 18 months with long-term rates reaching 6.10% by 2013/14 (excluding the debt guarantee fee of 1.0%) and then remain constant to 2028/29.

5) Foreign Exchange Rates

The US-Canadian exchange rate is projected to rise from the current level of 1.03 ($1.00 US = $0.97 Cdn) to 1.07 in 2012/13, 1.14 in 2016/17 and 1.15 by 2023/24.

6) Export Sales Contracts

The term sheets negotiated for the 15 year 500 MW Wisconsin Public Service sale (commencing in 2018) and the 14 year 250 MW Minnesota Power sale (commencing in 2022) will be finalized into long-term contracts. The 10 year Northern States Power contract extension of 375MW to 500MW (commencing in 2015) will also be finalized.

7) Carbon Pricing

Electricity export prices reflect anticipated greenhouse gas legislation and regulation which will likely impose significant constraints on emissions and will result in upward pressures on future market prices for electricity.

8) Capital Expenditures

Investments in new property, plant and equipment are projected to be significant during the first decade with major expenditures on Wuskwatim, Keeyask, Conawapa and Bipole 3 (total capital expenditures to 2019/20 projected to be $16.5 billion). The second decade will see the completion of Conawapa in 2022/23 plus the addition of new transmission to the US. No other new major generation and transmission projects are forecast in the second decade of the forecast. Figure 1 illustrates projected capital expenditures by major categories including new major generation & transmission, gas and other electric capital requirements including system refurbishment and upgrades necessitated by aging infrastructure.

NET INCOME AND FINANCIAL TARGETS

Projected consolidated net income, equity ratios, interest coverage ratios, and capital coverage ratios for the 20 Year Financial Outlook are depicted in Table 1 and Figures 2 to 5.

Table 1
20 YEAR FINANCIAL OUTLOOK

Year Ending March 31	NET INCOME (Millions)	RETAINED EARNINGS (Millions)	RATIOS Debt/Equity	Interest Coverage	Capital Coverage
2009 (actual)	$ 298	$2 120	75:25	1.58	1.81
2010	129	2 227	74:26	1.24	1.39
2011	88	2 315	75:25	1.15	1.09
2012	98	2 396	76:24	1.15	1.14
2013	83	2 479	76:24	1.12	1.28
2014	137	2 616	78:22	1.19	1.25
2015	122	2 738	79:21	1.15	1.52
2016	260	2 997	80:20	1.30	1.86
2017	271	3 268	80:20	1.27	1.83
2018	246	3 515	80:20	1.23	1.91
2019	257	3 772	80:20	1.22	2.14
2020	287	4 059	79:21	1.22	2.56
2021	307	4 366	79:21	1.24	2.23
2022	450	4 816	78:22	1.36	2.19
2023	554	5 369	76:24	1.44	2.25
2024	744	6 113	73:27	1.58	2.53
2025	805	6 918	70:30	1.65	2.45
2026	922	7 840	66:34	1.77	2.74
2027	1 019	8 859	61:39	1.88	2.85
2028	1 127	9 986	56:44	2.02	3.07
2029	1 237	11 223	51:49	2.18	3.09

Note: Assumes projected rate increases of 2.9% April 1, 2010; 2.9% April 1, 2011; 3.5% from 2013 to 2020; and 2.0% from 2021 to 2029.

CONSOLIDATED PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
REVENUES											
General Consumers	1,652	1,670	1,739	1,808	1,869	1,953	2,028	2,101	2,178	2,256	2,336
Extraprovincial	414	383	554	583	615	590	701	729	742	894	1,093
	2,066	2,054	2,293	2,390	2,484	2,543	2,729	2,830	2,920	3,151	3,429
Cost of Gas Sold	351	332	340	346	342	349	350	351	352	353	352
	1,715	1,722	1,953	2,044	2,142	2,193	2,379	2,479	2,568	2,798	3,077
Other	28	29	31	32	32	33	34	34	35	36	36
	1,742	1,751	1,984	2,076	2,174	2,227	2,412	2,513	2,603	2,834	3,113
EXPENSES											
Operating and Administrative	446	456	482	492	501	512	522	532	555	568	589
Finance Expense	454	451	509	569	570	588	574	590	632	719	923
Depreciation and Amortization	394	415	438	469	481	502	513	519	540	573	607
Water Rentals and Assessments	120	110	111	113	114	114	115	115	115	115	124
Fuel and Power Purchased	103	131	248	249	259	268	296	341	362	440	418
Capital and Other Taxes	97	99	100	104	109	116	125	134	140	146	150
	1,613	1,663	1,888	1,995	2,035	2,100	2,144	2,231	2,344	2,562	2,812
Non-controlling Interest	-	-	1	1	(2)	(5)	(9)	(11)	(12)	(15)	(14)
Net Income	129	88	98	83	137	122	260	271	246	257	287
Additional General Consumers Revenue											
General electricity rate increases		2.90%	2.90%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%
General gas rate increases		0.00%	1.50%	0.00%	1.00%	0.00%	1.00%	0.00%	1.00%	1.00%	0.00%
Financial Ratios											
Equity	26%	25%	24%	24%	22%	21%	20%	20%	20%	20%	21%
Interest Coverage	1.24	1.15	1.15	1.12	1.19	1.15	1.30	1.27	1.23	1.22	1.22
Capital Coverage	1.39	1.09	1.14	1.28	1.25	1.52	1.86	1.83	1.91	2.14	2.56

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CONSOLIDATED PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	2021	2022	2023	2024	2025	2026	2027	2028	2029
REVENUES									
General Consumers	2,392	2,454	2,514	2,581	2,651	2,721	2,801	2,877	2,957
Extraprovincial	1,201	1,223	1,379	1,758	1,940	1,908	1,903	1,928	1,950
	3,593	3,677	3,892	4,338	4,591	4,630	4,704	4,805	4,907
Cost of Gas Sold	351	350	350	349	348	347	346	346	345
	3,242	3,327	3,543	3,990	4,243	4,283	4,358	4,459	4,562
Other	37	38	39	39	40	41	42	42	43
	3,279	3,364	3,581	4,029	4,283	4,324	4,399	4,502	4,605
EXPENSES									
Operating and Administrative	602	615	634	647	660	673	686	699	713
Finance Expense	1,004	897	937	1,118	1,214	1,174	1,142	1,086	1,029
Depreciation and Amortization	634	639	667	729	773	789	807	810	821
Water Rentals and Assessments	129	130	136	150	154	155	155	156	157
Fuel and Power Purchased	435	459	473	459	492	420	395	424	445
Capital and Other Taxes	143	147	153	154	155	156	157	158	159
	2,947	2,887	3,000	3,257	3,448	3,367	3,343	3,334	3,324
Non-controlling Interest	(25)	(27)	(28)	(29)	(30)	(34)	(38)	(41)	(43)
Net Income	307	450	554	744	805	922	1,019	1,127	1,237
Additional General Consumers Revenue									
General electricity rate increases	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
General gas rate increases	0.00%	1.00%	0.00%	1.00%	1.00%	0.00%	1.00%	0.00%	1.00%
Financial Ratios									
Equity	21%	22%	24%	27%	30%	34%	39%	44%	49%
Interest Coverage	1.24	1.36	1.44	1.58	1.65	1.77	1.88	2.02	2.18
Capital Coverage	2.23	2.19	2.25	2.53	2.45	2.74	2.85	3.07	3.09

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CONSOLIDATED PROJECTED BALANCE SHEET
(In Millions of Dollars)

For the year ended March 31	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
ASSETS											
Plant in Service	13,097	13,626	15,691	16,213	16,654	17,387	17,844	18,579	21,071	22,401	25,835
Accumulated Depreciation	(4,800)	(5,171)	(5,562)	(5,985)	(6,414)	(6,864)	(7,320)	(7,787)	(8,275)	(8,799)	(9,357)
Net Plant in Service	8,297	8,455	10,129	10,228	10,240	10,523	10,524	10,792	12,796	13,602	16,478
Construction in Progress	1,949	2,460	1,343	1,820	2,840	3,856	5,534	6,950	6,161	6,448	4,170
Current and Other Assets	2,421	2,374	2,503	2,551	2,328	2,482	2,673	2,885	3,191	2,975	3,309
Goodwill	107	107	107	107	107	107	107	107	107	107	107
	12,775	13,397	14,082	14,705	15,516	16,968	18,838	20,734	22,256	23,133	24,065
LIABILITIES AND EQUITY											
Long-Term Debt	7,816	8,613	9,071	8,786	10,366	11,522	13,140	14,429	15,363	16,446	14,164
Current and Other Liabilities	2,246	2,000	2,187	2,983	2,165	2,365	2,391	2,750	3,104	2,645	5,573
Contributions in Aid of Construction	293	291	285	280	276	273	272	270	268	267	267
Retained Earnings	2,227	2,315	2,396	2,479	2,616	2,738	2,997	3,268	3,515	3,772	4,059
Accumulated Other Comprehensive Income	192	178	143	178	94	71	38	17	6	3	3
	12,775	13,397	14,082	14,705	15,516	16,968	18,838	20,734	22,256	23,133	24,065
Equity Ratio	26%	25%	24%	24%	22%	21%	20%	20%	20%	20%	21%

CONSOLIDATED PROJECTED BALANCE SHEET
(In Millions of Dollars)

For the year ended March 31	2021	2022	2023	2024	2025	2026	2027	2028	2029
ASSETS									
Plant in Service	26,935	27,406	31,328	34,430	35,739	36,567	37,186	37,941	38,573
Accumulated Depreciation	(9,943)	(10,538)	(11,165)	(11,855)	(12,595)	(13,354)	(14,132)	(14,916)	(15,711)
Net Plant in Service	16,991	16,868	20,164	22,575	23,144	23,213	23,054	23,025	22,861
Construction in Progress	4,525	5,456	3,114	879	273	121	210	207	340
Current and Other Assets	3,508	3,043	3,322	3,932	4,819	5,268	6,414	7,631	8,904
Goodwill	107	107	107	107	107	107	107	107	107
	25,132	25,474	26,706	27,493	28,343	28,710	29,784	30,971	32,213
LIABILITIES AND EQUITY									
Long-Term Debt	17,423	17,855	18,657	18,659	18,061	18,064	18,066	18,008	17,760
Current and Other Liabilities	3,075	2,536	2,413	2,453	3,095	2,537	2,587	2,702	2,951
Contributions in Aid of Construction	266	266	267	267	268	270	272	275	279
Retained Earnings	4,366	4,816	5,369	6,113	6,918	7,840	8,859	9,986	11,223
Accumulated Other Comprehensive Income	2	1	(0)	0	0	0	0	0	0
	25,132	25,474	26,706	27,493	28,343	28,710	29,784	30,971	32,213
Equity Ratio	21%	22%	24%	27%	30%	34%	39%	44%	49%

TAB 6

2.4 Manitoba Electricity Load Forecast

General consumers revenue is forecast based on the future load requirements in Manitoba as projected in the 2012 Electric Load Forecast.

The 2012 Electric Load Forecast projects that average annual growth in Manitoba load will be 1.6% for both gross firm energy and gross total peak over the 20-year forecast period to 2031/32 (compared to 1.5% in IFF11). Gross firm energy supplied to the Manitoba load is projected to grow from 24 961 GW.h in 2012/13 to 33 425 GW.h by 2031/32. Over the same 20-year period, total system peak is projected to grow from 4 491 MW in 2012/13 to 6 032 MW in 2031/32. The system load factor is projected to remain relatively constant at approximately 63%.

Compared to the 2011 forecast, gross firm energy is 212 GW.h lower in 2012/13 due mainly to lower forecasted industrial and general service loads. Over the 10-year forecast, the difference narrows due to the increased forecast of customers and by 2021/22 the forecast is only lower by 28 GW.h. By 2030/31, the gross firm energy forecast is higher by 359 GW.h. Gross total peak is lower throughout the forecast due to a lower estimate of distribution losses at peak of 4.5% of sales.

2.5 Extraprovincial Revenue

IFF12 includes the following existing and proposed long-term firm export sales:

Northern States Power 500 MW Power Sale	To April 2014
Minnesota Power 50 MW System Participation Sale	May 2009 to April 2015
Northern States Power 375/325 MW System Power Sale	May 2015 to April 2025
Great River Energy 150 MW Seasonal Diversity Sale	May 1995 to April 2015
Northern States Power 350 MW Seasonal Diversity Sale	May 2015 to April 2025
Northern States Power 125 MW System Power Sale	May 2021 to April 2025
Wisconsin Public Service 100 MW Sale	June 2021 to May 2027
Minnesota Power 250 MW System Participation Sale	June 2020 to May 2035
Great River Energy 200 MW Seasonal Diversity Sale*	May 2015 to April 2025
Wisconsin Public Service 300 MW Term Sheet Sale*	June 2026 to May 2036

* Proposed

Extraprovincial sales volumes are forecast for the first forecast year (2012/13) based upon the expected inflow conditions as of August 2012 and actual reservoir and lake level elevations as of July 2012. The second forecast year uses the median of 80 years of historic inflows and initial reservoir and lake level elevations carried forward from the 2012/13 forecast. For subsequent years, the projections are determined by averaging the revenues using flow conditions for the past 99 years (1912/13 to 2010/11).

TAB 7

Load Variability

Uncertainty is an inherent characteristic of forecasting. The load will vary both year to year and long term because of underlying changes in population growth, economic growth, changes in the operations of Top Consumers, and overall use patterns. An economic recession will slow energy growth. An economic boom will increase it. Cycles cannot be predicted in advance so some appropriate midpoint must be chosen as the forecast.

This forecast was created as Manitoba Hydro's best estimate of Manitoba's future energy requirement. The expectation is that there will be a 50% chance that actual growth will be higher than the forecast, and a 50% chance that actual growth will be lower than the forecast.

To evaluate the potential for variation, historic load variability has been analyzed using a probabilistic-based approach. Variations in annual weather adjusted load that have occurred in the past are used to estimate future variation. Doing this provides an estimate of the magnitude of the potential load variation from the forecast due to population, economy and other effects. 10% and 90% confidence bands (-/+ 1.28 standard deviations) were selected to be a proxy for the Low and High Load Forecast Scenarios for use in risk analysis studies. They are calculated as follows:

Load = Base Forecast -/+ 1.28 x Standard Deviation

For other probability points, substitute for the 1.28 the following numbers:

Prob	0.1%	2.5%	10%	20%	50%	80%	90%	97.5%	99.9%
Z(Prob)	-3.09	-1.96	-1.28	-0.84	0.00	0.84	1.28	1.96	3.09

This calculation gives the variability due to long term economic effects. It does not include variability due to weather which was removed through the use of weather adjusted load.

If variability due to weather is needed, the standard deviation of annual energy or annual peak due to weather has been found to be approximately 2% of the load. This 2% of load can be used as the standard deviation in a probability point calculation. The resulting variance can be added to the economic-based variance if a combined variance is needed. A straight addition of variances can be done because the weather is mostly independent of the economy.

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The following four charts and tables summarize the variability for energy and peak. By 2032/33, the Load Forecast has an 80% probability of being accurate to within ±2,471 GW.h or ±7.6%. Due to the inherent variability of the load, this is the best level of accuracy possible.

Figure 20 - Energy Variability

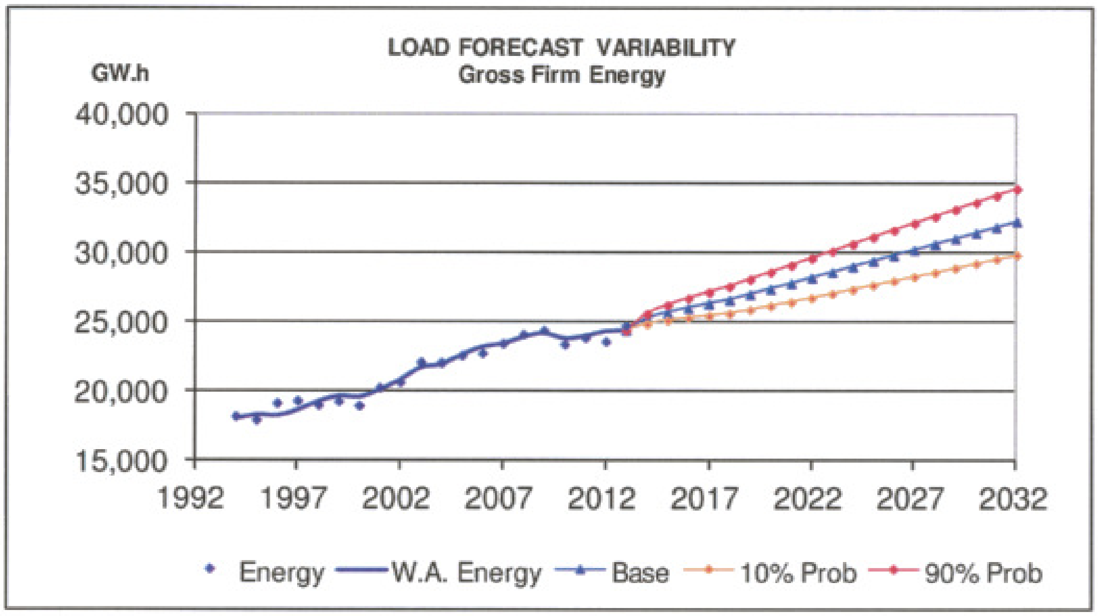

Table 33 – Energy Variability

Fiscal Year	Gross Firm Base Fcst	Long Term Economic Std Dev	10.0% Prob Point	90.0% Prob Point
2013/14	25239	284	24875	25603
2014/15	25676	434	25119	26232
2015/16	26013	557	25299	26727
2016/17	26322	667	25468	27176
2017/18	26606	767	25623	27589
2018/19	27003	862	25898	28107
2019/20	27398	951	26178	28617
2020/21	27789	1038	26460	29119
2021/22	28197	1121	26761	29634
2022/23	28605	1202	27065	30145
2023/24	29013	1280	27372	30654
2024/25	29418	1357	27679	31157
2025/26	29822	1433	27986	31658
2026/27	30225	1507	28295	32156
2027/28	30625	1579	28602	32649
2028/29	31041	1651	28925	33156
2029/30	31453	1721	29246	33659
2030/31	31863	1791	29568	34159
2031/32	32265	1860	29882	34649
2032/33	32667	1928	30196	35138

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TAB 8

MH/CAC - Harper MH 23 a)

Subject: Multiple Account Benefit Cost Analysis, Customer Account

Reference: Mr. Harper stated the following with respect to the Multiple Account Benefit Cost Analysis, customer account: "It is not at all clear why customer rate/bill impacts were not expressed in NPV terms,..."

Question: To the extent that the rate impacts in Chapter 13 were being used to illustrate distributional effects, does Mr. Harper agree that the cumulative effects on rates over time as shown is a better indicator (provides more information) than a single present value number. If not, please explain. Page 60

Response:

No, Mr. Harper does not agree. In Mr. Harper's view comparing the NPV of customer bills over a period of time for various alternatives is a better indicator (i.e. provides more information) than comparing the cumulative rate increase associated with each alternative over the same time period. The cumulative rate impact/increase measure only looks at the level of rates at the end of period under consideration and allows for no distinction as to when the increases occur during period of time in question. For example, consider two alternatives that both result in 25% rate increases over 10 years. The first alternative involves rate increases of 5% per annum (ignoring for simplicity the impact of compounding) in each of the first five years but no increases thereafter. The second alternative involves no rate increases for the first five year but 5% per annum increases in each of the last five years of the period. The cumulative rate impact measure will be the same for each (25%) even though customers will have paid significantly more in total bills over the 10 year period under the first alternative. In contrast, the NPV calculation does recognize when the rate increases occur during the period and, therefore, is a better measure of the bill/rate impacts over the period being considered.

MH/CAC – Harper 23 b)

Subject: Multiple Account Benefit Cost Analysis, Customer Account

Reference: Mr. Harper stated the following with respect to the Multiple Account Benefit Cost Analysis, customer account: "It is not at all clear why customer rate/bill impacts were not expressed in NPV terms,... " Page 60

Question: What discount rate would Mr. Harper recommend for the present value calculation he suggests should be calculated and why?

Response:

Ideally any discounting of customer bill/rate impacts for purposes of assessing customer impacts would be done at the time preference for money applicable to

Manitoba Hydro's domestic ratepayers. Mr. Harper is not aware of any authoritative work related to the determination of such a value or, more broadly, for electric ratepayers in general.

A review of the relevant references cited by Manitoba Hydro in NFAT Chapter 13 indicates that time preference rates are frequently linked to interest rates for savings. Marvin Shaffer, in his Multiple Account Benefit-Cost analysis text (pages 122 and 126) cites various values for time preference rates in the 1.5% to 4.1% range This range is generally consistent with the 3.5% savings rates used by Burgess & Zerbe (NFAT Application, Chapter 13, Footnote #7), although these were derived on a different basis. The Ontario Power Authority, in its 2007 IPSP filing with the OEB, used a 4% real discount rate, which was meant to be reflective of resident savings rates (EB-2007-0707, Exhibit D/Tab 3/Schedule 1/Attachment 1)

One of the principles underlying the aforementioned approach is that consumers are net savers and therefore receiving/not receiving funds sooner versus later will impact on savings. However, there are segments of society (and also ratepayers) where this is not case. For residential customers, this could include low income households and indebted households where the time preference rate is likely to be higher. Indeed, in such cases the "rate" could be considerably higher if based on the interest rate charged on credit cards or late payment of hydro bills. Also, it overlooks the fact that in the case of electricity ratepayers a large portion of the revenue comes from businesses (e.g. in Manitoba Hydro's case – over 50%) and not households where delayed "consumption" may well be represent delayed investment in business activities. The real return on equity used in ECS's revised Manitoba Hydro WACC calculation is in the order of 8% real and reflects the return expectations for a relatively low risk investment.

Overall this would suggest that the appropriate time preference rate is somewhere in the range of 3% - 8%. For purposes of an initial calculation a discount rate of 5.5% would seem reasonable. However, given the range some sensitivity analysis would be in order.

TAB 9

REFERENCE: Chapter 11: Financial Evaluation of Development Plans

QUESTION:

For scenarios that do not proceed with a given resource which has a "sunk" cost associated with it (e.g., Keeyask), please provide all assumption used in expensing/amortizing the sunk costs in the financial analysis.

RESPONSE:

For the purposes of the NFAT financial evaluation, development plans in which Keeyask, Conawapa or the U.S. interconnection are not constructed assume total costs to June 2014 are sunk costs and are amortized evenly over an 18-year period to 2032/33. As indicated on page 5 of Chapter 11 of the filing, the 18-year amortization period matches the annual amortization of the sunk costs with the period of even-annual rate increases required to recover such costs and reach the 75:25 debt/equity ratio target by 2031/32. The analysis is indifferent whether the recovery of sunk costs is over a shorter period due to the fact that the even annual rate increases were calculated to achieve the targeted debt/equity ratio by the end of 2031-32.

REFERENCE: Chapter 11: Financial Evaluation of Development Plans

QUESTION:

Please provide the full amortization schedule by year for amortizing each of the sunk costs for projects that do not (under various scenarios) proceed. Indicate which costs are being amortized and which type of costs (if any) are maintained as some form of deferred asset.

RESPONSE:

The following table provides a breakdown of the sunk costs by project and annual amortization expense associated with each project through to 2032/33 for the reference scenario. As indicated in MIPUG/MH I-003(a), total costs spent to June 2014 are assumed to be amortized over the 18-year period to 2032/33 for the purposes of the financial analysis. There are no costs assumed to be maintained in the form of deferred assets.

Conawapa Generating Station sunk cost amortization is applied in the All Gas (Plan 1), K22/Gas (Plan 2), K19/Gas/250 (Plan 4), and K19/Gas/750 (Plan 6) plans. Keeyask Generating Station and Transmission sunk cost amortization applies to the All Gas (Plan 1) and Gas/C26 (Plan 7) plans. The US Tie Line sunk cost amortization applies to the All Gas (Plan 1), K22/Gas (Plan 2) and Gas/C26 (Plan 7) plans. It should be noted that the sunk cost amortization under high capital cost/high economic indicator and low capital cost/low economic indicator scenarios do not change materially from the reference scenario.

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Total Sunk Costs and Amortization Expense by Project:

(in $ millions)		Fiscal Year ------>																		
Project		**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
Conawapa Generating Station	Total Sunk Cost	376.1																		
	Annual Amortization Expense	13.9	20.9	20.9	20.9	20.9	20.9	20.9	20.9	20.9	20.9	20.9	20.9	20.9	20.9	20.9	20.9	20.9	20.9	7.0
Keeyask Generating Station	Total Sunk Cost	1,186.7																		
	Annual Amortization Expense	51.8	65.9	65.9	65.9	65.9	65.9	65.9	65.9	65.9	65.9	65.9	65.9	65.9	65.9	65.9	65.9	65.9	65.9	14.2
Keeyask Transmission	Total Sunk Cost	13.4																		
	Annual Amortization Expense	0.4	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.3
US Tie Line	Total Sunk Cost	1.2																		
	Annual Amortization Expense	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0
	Total Sunk Cost	1,577.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Total Annual Amortization Expense	66.17	87.64	87.64	87.64	87.64	87.64	87.64	87.64	87.64	87.64	87.64	87.64	87.64	87.64	87.64	87.64	87.64	87.64	21.46

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REFERENCE: Executive Summary; Table 4; Page No.: 29

QUESTION:

Please provide the rationale for aggressively pursuing a 75:25 debt:equity ratio by 2031/32 when the level of rates required to achieve this level are well above the go-forward level of rates needed to maintain a reasonable Interest Coverage Ratio.

RESPONSE:

Manitoba Hydro does not consider pursuing a 75:25 debt:equity ratio by 2031/32 to be aggressive. To maintain the targeted 1.20 interest coverage ratio throughout the next ten years would lead to a level of rates higher than those forecasted in the financial analysis included in Chapter 11.

REFERENCE: Question MIPUG/MH I-17b

QUESTION:

Please provide the same information for the Conawapa income opportunities - specifically how have these been estimated and where are they represented in Appendix 11.4 tables.

RESPONSE:

An assumption regarding Conawapa income opportunities has been included in financial evaluation and aggregated in the pro forma financial statements found in Appendix 11.4. However, the terms of Conawapa income opportunities are currently under negotiation and cannot be disclosed by Manitoba Hydro at this time.

TAB 10

Commercial Evaluation of Manitoba Hydro Preferred Development Plan Business Case

Prepared by Morrison Park Advisors
For

Manitoba Public Utilities Board

January 2014

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that they were prepared with all due care based on the professional qualifications of those responsible for them.

It is critical to point out, however, the fundamental uncertainty that underlies many of the projections in question, particularly as they extend out not only years, but decades. Useful forecasts for the near to medium term are typically based on the belief – sometimes proven by subsequent events to be erroneous – that the future will consist of incremental changes to the practices of the past. However, the longer the time horizon of the forecast, the more likely that changes will cease to be incremental, and become truly unpredictable. What may appear to be reasonable today may at some point in the future – with the benefit of hindsight – look like a terrible mistake, or a massive stroke of luck. Prices change, technology changes, market dynamics change, the relative cost of goods changes: all in unpredictable ways over time.

Technological advances, in particular, can render assumptions obsolete even in relatively short periods of time. The development of hydraulic fracturing in the natural gas industry over the past decade is only a recent example of expectations about future market conditions being totally undermined: widespread expectations a decade ago were that North America would by now be supply constrained and increasingly reliant on expensive imports of natural gas from elsewhere, yet now there is a rush to find ways to export an overabundant commodity that has dropped dramatically in price. In earlier decades similar received wisdom was overturned (for example, there was a time in the mid-twentieth century when many experts believed that nuclear power would render electricity "too cheap to meter".[1] Needless to say, the aspiration was never achieved).

There is a significant danger in assuming that a view of the future from the perspective of today will be very accurate. All such assumptions should be approached with humility, and treated with respect as the best available basis for decision-making, but without claiming them to be more than what they are. Decisions cannot be made without taking a view of the future, but the future may prove unwilling to agree with the forecasts made of it.

It is commonplace that commercial transactions are analyzed using mathematical models, often providing a degree of precision measured in decimal points, which sometimes gives the illusion of accuracy or predictive power. We have used such models in the preparation of this Report. However, these models are only as accurate as the assumptions about the future that underlie them. Since those assumptions must be given a broad range because of the difficulty inherent in predicting the future, especially over decades, the models should and do result in outputs with an equally broad range. This means that mathematical models sometimes may be capable of excluding certain decision options from the realm of reasonable commercial choice, but cannot always point to a single preferred outcome among several. In these cases, decisions still must be made, but they must be rendered on the basis of judgement.

Commercial decisions are ultimately about judgement, and judgement is extremely difficult to quantify.

[1] The phrase was coined by Lewis L. Strauss, Chairman of the United States Atomic Energy Commission in a 1954 Speech to the National Association of Science Writers.

assumed "time value" of ratepayer money, it does not make sense to combine these figures, but rather to consider each matrix separately.

The second notable fact is that within each matrix, rows of numbers are closer to each other than columns of figures are. This makes clear that the assumptions made about economics, and particularly the inflation rate, overwhelms any difference between Resource Plans. In other words, assuming an average of 2% inflation over 48 years instead of 3% makes a bigger difference to the outcome than choosing one Resource Plan over another. Since inflation over the next 48 years will average either 1%, 2% or 3%, but will not be all three simultaneously, it does not make sense to combine these rows of numbers, but rather consider them separately.

A third fact, less instantaneously obvious, but nevertheless easily calculated, is that within each row, the deviation from the mean of the row is not more than 2.5%. This means that regardless of the Resource Plan chosen, *the model results in total risk-adjusted present value costs to ratepayers over a 48-year period that are all within a maximum of 5% of each other*. In many ways, this is a remarkable result. The Resource Plans are radically different in their choices of infrastructure elements, use of fuels, orientation towards exports, etc., and yet the differences do not appear to translate beyond the marginal. However, it should be recalled that Manitoba Hydro's existing resources total more than 5,500 MW of peak capacity, with maximum annual energy output of more than 38,000 GWh. In the first fifteen years of the five resource plans, between 700 MW and 2,000 MW of peak capacity is added, and maximum system energy is increased by anywhere from 0 GWh to 13,000 GWh. In other words, since the existing electricity system, dominated by hydroelectricity, continues to be the majority of the system for a very long time to come despite the choice of Resource Plan made, it should not actually be surprising that the incremental Resource Plan choice does not have an overwhelming impact on total costs to ratepayers.

There is another contributor to this outcome, however, which can only be discovered through analysis of raw model outputs: prior to the implementation of any of the Resource Plans, the existing system is taking on a substantial amount of debt as a result of system investments (including Bipole III, the most significant single component). This is a particularly heavy burden to bear for the All Gas Resource Plan (1), because that plan is the least export oriented, and hence the least likely to generate "extra" revenues that could help to quickly amortize those debt burdens. For the higher capital plans, the existing debt burdens are less severe compared to the debt burdens being assumed as part of the resource plan itself, and the export orientation also provides much higher net income to compensate for the overall debt burden, and hence differences between the plans which might otherwise have been starker are somewhat muted.

A third factor contributing to the lack of difference between the outcomes of the Resource Plans relates to the treatment of sunk costs in the Keeyask and Conawapa projects. In the All Gas Plan (1), all spending to date on the proposed hydroelectric facilities is written off. For ratepayers, this amounts to an incremental debt burden which must be retired, without any compensating benefits (in the other plans, since the facilities are actually built the sunk costs are an investment with associated benefits, as opposed to a loss to be written off). This fact is inescapable, because real dollars have been spent and must be recovered from ratepayers. However, the reality of the sunk costs does tend to moderate the differences between the 48-year outcomes of the Resource Plans.

A final observation to make on the matrices is the rank ordering of Resource Plans from lowest ratepayer cost to highest ratepayer cost:

<u>Figure 7. Rank Ordering of Resource Plan Cost to Ratepayers</u>

Discount Rate	Economic Variables	Lowest				Highest
6%	Reference	4	6	1	14	12
	High	4	6	1	14	12
	Low	4	6	14	12	1
10%	Reference	4	1	6	14	12
	High	1	4	6	12	14
	Low	4	6	14	1	12

From this rank ordering, some patterns begin to emerge:

- Resource Plans 4 and 6, which include Keeyask, some level of transmission interconnection and natural gas plants, appear to fare consistently better than the other options
- Plans 14 and 12, which include Conawapa, are consistently ranked as more costly to ratepayers than Plans 4 and 6, which include Keeyask but not Conawapa
- Plan 1, the All Gas Plan, ranks poorly when economic variables such as inflation and interest rates are low, but better when they are moderate or high; this is particularly true with respect to the Preferred Plan 14, which is superior to All Gas in the low economics environment but not otherwise
- Plan 1, the All Gas Plan, ranks relatively poorly when the discount rate is lower at 6%, but better when the discount rate is higher at 10%, suggesting that the relative time value of money is an important consideration
- Plan 4, with a 250 MW interconnection, always ranks better than Plan 6, with a 750 MW interconnection; however, returning to the figures themselves it is notable that these two plans are never more than 1% apart from each other in any of the cases
- Similarly, Plan 14 is better than Plan 12 in every case but one, suggesting that an earlier construction and export orientation for the Conawapa facility is better than a later one; however, the difference between these plans is also always less than 1%.

Consideration of these rate patterns also points to the issue of the future beyond the 48th year of the model. If the model were extended out even further, for example for another full twenty-four years (another "generation"), a few additional observations would be warranted:

- The Preferred Development Plan (14), and Plan (12) which also includes Conawapa, would produce lower ratepayer costs than would any of the other three Resource Plans, none of which include Conawapa
- The present value of that presumed set of additional results would be much higher if it were discounted at the low rate of 6% rather than the higher rate of 10%; at a discount rate of 10%, the total value of all years beyond 48 would be less than one twentieth of the total value of the first 48 years; whereas at a 6% discount rate, the total value of years beyond 48 would be several times greater
- For every year the model is extended beyond 48, the more the rank orderings of the Resource Plans will change in favour of Plans 14 and 12, particularly with the lower discount rate of 6%; however, with the higher discount rate of 10%, the shifting of the rank ordering will slow down and eventually stop because of the rapidly declining importance of those future years.

With respect to the issue of time value of money and the varying rate patterns displayed by the Resource Plans, it should be recalled that:

- The second half of the 48-year time period is inherently more uncertain than the first half, in the sense that future conditions are harder to predict so far in advance: technology is always changing, economic growth patterns change, climate may be changing, etc., so making accurate predictions about any variables (fuel costs, export costs, construction costs, the efficiency of equipment in the future, etc.) is that much more difficult;
- On the other hand, some things are undeniably knowable from today's standpoint, such as that waterpower is a very inexpensive "fuel", so that *at some point* facilities like Conawapa always become very attractive assets for ratepayers <u>of the day</u>; an important question is whether ratepayers today and in the near future do or should care about the welfare of ratepayers decades away.

4.2.2. The Impact of Manitoba Demand

All of the analysis to this point has assumed a single pattern for the electricity demand of Manitoba ratepayers in the future. However, as has been noted above and by others, there is considerable uncertainty about what Manitoba demand will actually be, particularly as decades pass.

Manitoba Hydro provided raw SPLASH data for the performance of the electricity system in high and low demand alternative futures for both the All Gas Plan (1), and the Preferred Development Plan (14). When this data was applied to the financial model, the following results for ratepayer costs resulted:

5.1.2. Discount Rate

Manitoba Hydro chose to utilize its WACC as the discount rate in all of its present value calculations. The justification is presented as follows in s. 9.2.3 of the Business Case:

> The starting point for development of a discount rate is a company's overall cost of financing. As a discount rate is used to guide investment decisions based on uncertainty, a risk premium may be identified to arrive at a discount rate which makes the investor indifferent between cash amounts received at different points in time.

Manitoba Hydro used the reference WACC as its discount rate (either nominal of 7.05% or real of 5.05%) throughout its analysis, except with respect to updated 2013 figures, when the reference real WACC was increased to 5.40% because of increases in some of the underlying consensus forecasts.

Several observations can be offered:

- WACC is the appropriate concept to consider the present value of cash streams in the future for the purposes of an investor considering an investment decision, however, Manitoba Ratepayers are not investors
- While it is true that Manitoba Hydro will source the capital required for its chosen Resource Plan from a combination of debt and retained earnings, and while the retained earnings are at least partially derived from ratepayer revenues, ratepayers can in no sense be understood to be making a voluntary investment decision, particularly given the monopoly nature of the utility service that is being offered, and the decision-making authority that rests in the hands of the government
- Calculation of the WACC, and its use in models predicting Manitoba Hydro's financial results – and hence electricity rates that ratepayers will face – is entirely appropriate given the likely use of the formula in the setting of rates over time by the PUB, however, this does not automatically qualify the WACC for use as the discount rate relevant to all parties considering the Business Case
- From the perspective of ratepayers, or any other stakeholder considering the Business Case, the primary value of the discount rate is in providing a means to compare varying cash streams over time from the perspective of today, in essence, a "time value of money" which is appropriate to that stakeholder
- The primary stakeholders in the Business Case identified in this Report are ratepayers and the Government of Manitoba; notably, neither of these parties is directly and voluntarily investing equity in the project
- It can be argued that governments have very low "time values" of money, given the permanence of the institution, and typically its access to the lowest cost of funds; ratepayers,

however, are a heterogeneous group for whom generalizations are very difficult, and for whom the adoption of a single, blended time value of money may not be appropriate.

While there is an existing literature with respect to the choice of appropriate discount rates to represent ratepayers, we have not pursued this issue further. For the purposes of this report the use of two discount rates was adopted, both nominal, at 6.00% and 10.00%. These rates bracket the rate adopted by Manitoba Hydro, and offer the possible consideration of the various resource plans from more than one perspective.

5.2. Exports

As has been discussed elsewhere in this report, Manitoba Hydro has generated a substantial portion of historical revenues from exports. Of these revenues, a significant portion is directly tied to short-term market prices, while another portion is the result of longer-term firm contracts. These contracts, however, are not specifically tied to any asset, but instead are based on the output of the Manitoba electricity system as a whole. As a result, their length, pricing schedule, and terms and conditions all reflect the underlying export electricity markets and counterparties with which Manitoba Hydro interacts.

These contracts can be contrasted with Manitoba Hydro's own contracts with the wind farms that have been constructed in the province. In those cases, Manitoba Hydro has purchased all of the output of the wind farms for their full expected life, at rates that were negotiated between the parties based on the cost of construction and operation of the wind farm plus an amount meant to represent a return on investment for the wind farm owners. These are classic "infrastructure project" contracts which effectively apportion and minimize the risks and costs of a project for both parties.

Manitoba Hydro has negotiated a number of agreements with parties as part of the development of the Preferred Development Plan, as described in the Business Case. The electricity resources that will be built as part of the Preferred Development Plan are hydroelectric facilities with an expected life of over 100 years. The contracts negotiated, however, have terms which last a fraction of that time. In addition, the price of the contracts is based on prevailing market conditions, and not in any way related to the cost of the electricity resources being built. They are in fact system energy arrangements, similar to the system energy arrangements that Manitoba Hydro has signed in the past. As such, their chief usefulness is in providing Manitoba Hydro with a guaranteed buyer for a portion of the system's expected surplus power, and a firm price for a period of time, which provides additional predictability to cash flows.

Considered more broadly, Manitoba is simply a price taker in the MISO market, whether it is taking prices in short-term markets, or in a longer-term market for bilateral arrangements with specific counterparties. The value of the longer-term contracts negotiated at any time are likely, as Potomac Energy, another independent expert consultant to the PUB, has argued in their report,[41] to be based on the cost of new entry into the MISO market (or in other words, the cost of constructing new supply resources in the MISO market at the time a contract is negotiated). As a result, the longer-term firm

[41] Please see Report to the PUB provided by Potomac Energy on January 15, 2014.

contracts are not mitigating market risk or exposure for Manitoba Hydro, but merely apportioning the market risk accepted in pursuing the Preferred Development Plan.

In this respect, Manitoba Hydro is acting as a "merchant" investor, taking substantial market risk based on expectations, or bets, about the future. While "probabilities" have been placed on different potential futures through the scenario modeling process, fundamental market risks are necessarily imbedded in some Resource Plans to a far greater extent than in others. Prices will either turn out to be high, and ratepayers will benefit, or they will turn out to be low, and ratepayers will have to shoulder more of the burden of Manitoba Hydro costs. Either way, ratepayers can have no certainty in advance, and no choice in the matter.

Given the legislative mandate of Manitoba Hydro to reinvest all earnings, and keep rates as low as possible, it is clearly not a merchant investor. However, the tacit acceptance of risks that would be normally within the scope of a merchant investor suggests the issue deserves scrutiny.

5.3. Impacts on the Government of Manitoba

In s. 4.6, the potential for and magnitude of Manitoba Hydro financial distress was discussed. It was suggested that depending on the choice of resource plan, the timing, and the depth of a drought event, it is possible that for a period of time Manitoba Hydro could suffer a sustained period of financial distress which could result in the view that the company is no longer fully self-supporting. Many factors would play into this conclusion, including the longevity of the distress, and the severity. However, in certain scenarios, if a severe drought were to occur in the 2020s, there is the possibility that the approximate equivalent of $10 billion or more of Manitoba Hydro debt could be viewed as not "financially supported" by rates.

In practice, what this would mean is that the Government of Manitoba would have to lend additional sums to Manitoba Hydro in order for the company to meet its cash requirements (both to pay debt interest and refinance expiring principal, and to finance the purchase of necessary capital goods). The ability of the government to provide such funding is not called into question, but rather it is the potential impact on the view of the Province by credit rating agencies and other capital markets actors that is in question.

5.3.1. Manitoba Financial Profile

Currently, Manitoba is positively viewed by credit rating agencies, and maintains a high rating (Aa1 from Moody's, AA from Standard and Poors and A (high) from DBRS). Recent credit reports, which have been provided as part of the NFAT process, have highlighted the relatively strong and stable economic performance of the province in the years since the financial crisis of the last decade, the varied sources of strength in the province's economy, its population growth through immigration, and the stable fiscal and financial management of the government.

Projecting forward ten, twenty or thirty years to a possible financial distress episode at Manitoba Hydro on the basis of current estimates is a tenuous exercise at best, both because of the time involved, and

6. Costs, Risks and Benefits

6.1. Ratepayers

As identified in Chapter 2, the primary interest for Manitoba ratepayers is to pay the lowest risk-adjusted cost for their electricity over time.

In some sense, both the cost and the benefit for ratepayers is the same thing: the monthly bill for the electricity they consume. Through financial modeling, the five Resource Plans were compared across all 27 scenarios and 21 hydrology patterns. The rank ordering of the Resource Plans very much depends on whether a scenario is isolated, or whether several scenarios are allotted probability weights.

Risk is the principal differentiator between the Resource Plans. Choice of a Resource Plan is in large measure a choice about the risks that Manitoba Hydro will be financially sensitive to, and which will be passed on to Ratepayers in the form of rates.

Table 8. Risk and Impacts Across Development Plans

Risk	Impacts
Demand	• Smaller, shorter construction-time resources can be more accurately targeted to expected domestic demand, favouring Plan 1 • All Plans can suffer if domestic demand stalls or declines after resources are built, though larger individual facilities in Plans 12 and 14 face such stranded asset risk to a greater degree; mitigated by the fact that "demand" need not be domestic demand • The impact in the event of lower demand depends on the relationship between export prices and domestic rates at the time the expected demand does not materialize; if prices have to rise steadily for a longer period, as in Plans 12 and 14, then more of this competitive advantage may be lost
Hydrology	• There is a clear difference in sensitivity to hydrology as between the Plans, with Plans 12 and 14 being most affected by water flows • The volatility of water flows translates directly into volatility of cash flows, which can be positive as well as negative
Export/Import Prices (& Fuel Prices)	• There is a clear difference in sensitivity to export markets and market prices between the Plans, with Plans 12 and 14 being most sensitive, but again, sensitivity can be both positive and negative • The reduced sensitivity in Plan 1 to changes in this set of variables may have much to do with the fact that fuel prices and export prices are tied together
Construction Costs	• The absolute magnitude and complexity of building a project like Conawapa increases risks
Interest Rate	• All Plans are dramatically affected by interest rates and inflation assumptions
Technology	• Plans with longer – lived assets forego the possibility of adapting to improvements in technology

TAB 11

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Appropriate Discounting for Benefit-Cost Analysis

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Appropriate Discounting for Benefit-Cost Analysis

David F. Burgess and Richard O. Zerbe

Abstract

In order to be sensible about what discount rate to use one must be clear about its purpose. We suggest that its purpose is to help select those projects that will contribute more net benefits than some other discount rate. This approach, which is after all the foundation for benefit-cost analysis, helps to reconcile different suggested procedures for determining the discount rate. We suggest that the social opportunity cost of capital (SOC) is superior to other suggested approaches in its generality and its ease of use. We use the SOC to determine a range of real rates that vary between 6% and 8%. We suggest that approaches based on determination of preferences, which result in hyperbolic discounting, are less appropriate and less useful.

KEYWORDS: discount rate

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Introduction

Perhaps no methodological question within benefit-cost analysis (BCA) has been so widely discussed as the discounting of future benefits and costs. The body of literature regarding this subject is vast. However, it is also unresolved. Little consensus can be found on issues such as what should be discounted, or on the choice of a discount rate. Sources of discrepancy include: (1) the effects of risk; (2) displacement of private capital; (3) rate of time preference; (4) whether rates should be hyperbolic with respect to the time period in which effects are felt (an issue related to the use of time preferences); (5) ethical issues such as whether the changing wealth of future generations should allow for rates that reflect preferences for income (a marginal utility of money that is different from those at the time the project is initiated) (Weitzman 2001; Moore et al. 2004; Dasgupta 2008) and (6) whether or not certain goods such as lives and health are special and should not be discounted. Part of the problem lies in the fact that proponents of different approaches to discounting are frequently unclear about what they are maximizing, or what function the discount rate is supposed to perform. In this paper we take the position that the basic principles that underlie benefit-cost analysis should be carried forward with respect to discount rates. The case for discounting arises from the concepts of time preference, uncertainty, and the opportunity cost of capital, all of which coalesce to underlie the simple premise that a dollar in hand today is held to be worth more than receiving that same dollar at any future point (US OMB 1992; 2003).

This paper assumes that the purpose of discounting is to select that rate which will lead to selection of the best projects in terms of maximizing net present values. We assume that projects should be chosen that meet the potential Pareto test.[1] This will occur when the present value of benefits compensates for the capital foregone and the consumption displaced. We find that the social opportunity cost approach to the discount rate is the most likely to meet this objective, and a major purpose of this paper is to develop a rate, or a range of rates, that can serve as a standard for best practice in the context of the U.S. economy.

Main Approaches

There are three main approaches to determining discounting rates: (1) the social opportunity cost of capital (SOC) approach, which proposes that the discount rate reflects the social (economic) opportunity cost of capital, a weighted average of

[1] Elsewhere Zerbe and Davis (2010) argues for replacing the potential Pareto test with a Pareto relevance test, but for our purposes here this makes no difference

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the pre-tax and after tax rates of return, and, in an open economy, the marginal cost of foreign funding, where the weights reflect the proportions of funding that are obtained from displaced investment, postponed consumption, and incremental funding from abroad when the government borrows to finance the project (Sandmo and Dreze 1971; Harberger 1972; 1985; Sjaastad and Wisecarver 1977; Burgess 2010a; 2011); (2) the social time preference (STP) approach (Marglin 1963; Feldstein 1972; Bradford 1975; Lind 1982), which discounts benefits and costs at the after-tax rate of return (or a politically determined social rate of time preference) but converts all investment displaced in financing (or induced by the project) into its consumption equivalent by multiplying by the shadow price of capital; (3) the marginal cost of funds criterion (MCF) (Liu 2003; Liu et al. 2004) which discounts within-generation benefits at the after tax rate, between-generation benefits at the pre-tax rate, and costs (including indirect revenue effects) at the pre-tax rate, but multiplies all costs and indirect revenue effects by a parameter reflecting the marginal cost of funds.[2] The MCF approach emphasizes the need for project evaluation to take into account the marginal social cost of raising the revenue necessary to cover any budgetary deficit that arises on account of the project.

Apparent differences between the SOC and MCF criteria arise from different interpretations of a project's indirect revenue effect. For the MCF criterion, the indirect revenue effect is the uncompensated effect of the project on tax revenue (holding income fixed) whereas for the SOC criterion it is the compensated effect (holding utility fixed). Apparent differences between the SOC and STP criteria arise from different assumptions about the private sector's knowledge of the project's benefits and costs. Burgess (2011) shows that these approaches can be reconciled. He does not indicate discount rate estimates for the SOC and this is our primary purpose here.

All approaches recognize that the displacement of private capital must be taken into account, but they differ in terms of whether it should be incorporated into the discount rate or reflected by a shadow price. Liu (2003) and Liu et al.'s (2004) MCF criterion depends upon an exogenous rate of return to capital, but Burgess (2011) shows that the MCF approach can be extended to situations where the rate of return to capital is endogenous. In this more general setting the MCF criterion requires that (within-generation) benefits be discounted at the after tax

[2] A fourth approach to discounting comes from the literature on optimal growth. Gramlich (1981), for example, proposes that under certain conditions the growth rate of the economy be used to determine a government discount rate. The idea is to accumulate that quantity of capital that maximizes steady state consumption per effective worker. Thus capital formation is justified whenever the rate of return net of depreciation exceeds the growth rate. However, it does not follow that any project whose internal rate of return exceeds the growth rate is worthwhile because there is no assurance that undertaking the project will divert resources solely from consumption rather than from other projects.

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rate of return (consumption rate of interest) but costs and indirect revenue effects must be discounted at the weighted average rate that is appropriate for the SOC criterion. Costs and indirect revenue effects must be multiplied by the MCF parameter that measures the marginal cost of raising a dollar of revenue using the particular tax instrument that is relevant. In this more general setting the fundamental equivalence between the MCF and SOC criteria continues to hold. The key insight is that the MCF criterion is evaluating the impact of a project on private surplus (present value of consumption discounted at the consumption rate of interest) by converting the budgetary cost of the project (present value of project expenditures minus indirect revenue effects discounted at the SOC rate) into its consumption equivalent cost using the MCF parameter, whereas the SOC criterion is measuring the impact of the project on government revenue holding private surplus fixed at its pre-project level. While the standard SOC criterion assumes that the marginal tax instrument is a lump sum tax, the SOC criterion can be adapted to situations when a distortionary tax is used instead. The weighted average discount rate is appropriate for the SOC criterion whether or not the marginal tax instrument is a lump sum tax.

The SOC approach is justified by the straightforward principles of applied welfare economics—demand price measures marginal benefit, competitive supply price measures marginal cost, and adding up (i.e. dollars of benefits and costs are valued independently of to whom they accrue) (Harberger 1971). The basic exercise is the extraction of resources from the economy, which displaces investment and stimulates saving and in an open economy attracts additional foreign funding. The discount rate should be consistent with choosing a project that is more productive over another that is less productive. The rate then must cover the productivity that is forgone as a consequence of displaced investment and the net-of-tax supply price of the newly induced savings and the marginal cost of incremental foreign funding. Any lower rate than the weighted average represented by the SOC will fail this test. Though one can find a number of ways to motivate lower rates, one cannot escape the penalty of ignoring the correspondingly higher social productivity of investment funds. Any higher rate will forego desirable projects.

The STP approach plays a prominent role in the academic literature on the social discount rate. Because our ultimate position is in support of the SOC approach, we will focus on comparing how the STP and SOC criteria perform in simple situations.

In the case of two period projects, where costs are incurred in period 1 and benefits accrue in period 2, the SOC and STP criteria give equivalent results if benefits are just like income. Thus, for a project with costs C1 and benefits B2 it is a matter of indifference whether one converts costs and benefits into "consumption equivalents" and discounts at the STP rate, or discounts

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unconverted benefits and costs at the SOC rate. Assuming that the capital market is the marginal source of funds for all projects and (for simplicity) that the pre-tax rate of return p is exogenous, the SOC rate will equal the pre-tax rate of return and the STP rate will equal the after tax rate of return r.[3] The wedge between the two rates is explained by the capital income tax so $r = p(1-\tau)$. If the private sector consumes the annuity value of wealth the consumption equivalent of a dollar of investment displaced will be equal to the ratio of the pre-tax rate of return to the after tax rate. In other words, the shadow price of a dollar of private investment displaced is p/r.

A project that costs $C1$ and provides benefits of $B2$ is worthwhile according to the SOC criterion if $-C1 + B2/(1+p) > 0$. Using the STP criterion, the project's cost is converted into its consumption equivalent by multiplying by the shadow price of investment (because the costs displace private investment dollar for dollar), and the benefit $B2$ is separated into an income component, B2-$C1$, which is available for consumption, and a "replacement of capital" component $C1$, which is reinvested. The project is worthwhile according to the STP criterion if $-C1\ (p/r) + [B2-C1+C1\ (p/r)]/(1+r) > 0$. But this is equivalent to the SOC criterion.[4]

If the benefits are fully consumed the project has no effect on private sector behavior, so ultimately it must be financed by raising taxes to balance the government's budget. If lump sum taxes are used, the project's cost has a consumption equivalent of $C1\ [p(1+r)/r(1+p)]$ and the project is worthwhile according to the STP criterion if $-C1\ [p(1+r)/r(1+p)] + B1/(1+r) > 0$.[5] However, in this case the SOC criterion requires that an "indirect revenue effect" be included along with the conventional benefit and cost estimates, but the appropriate discount rate is still the SOC rate. The benchmark for the SOC criterion is a project whose benefits are "just like income." In other words, providing the project and increasing lump sum taxes by an amount equal to the private sector's willingness to pay for the project leaves capital income tax revenue unchanged. Any project whose benefits are not equivalent to income will have an indirect revenue effect. For a project whose benefit $B2$ is fully consumed, the indirect revenue effect is the effect on capital income tax revenue of a lump

[3] The STP rate is interpreted by some as a "politically determined" rate that may lie below the after tax rate of return, but we set aside this issue in this section.

[4] Sjaastad and Wisecarver (1977) were the first to make this point. The SOC criterion and STP criterion yield different results for projects with long gestation lags, but the STP criterion fails to take into account the interim costs of financing such projects. See Burgess (2010).

[5] A lump sum tax increase of one dollar will reduce the present value of consumption by one dollar, but increase the present value of government revenue by just $r(1+p)/p(1+r)$ dollars. This is because the private sector discounts consumption at rate r but government revenue is discounted at rate p. If the government needs to raise $C1$ dollars to finance the project, the cost in terms of current consumption is $C1$ multiplied by $p(1+r)/r(1+p)$.

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sum tax increase of $B2$ in period 2. Assuming that the private sector consumes the annuity value of wealth, capital income tax revenue will increase in period 2 by $\tau prB2/(1+r)^2$, and decrease in periods 3 and thereafter by $\tau pB2/(1+r)^2$. The present value of the project's indirect revenue effect (discounted at the SOC rate) is therefore $\tau B2(p.r-1)/(1+r)^2(1+p)$. Including the indirect revenue effect along with the conventional benefit and cost estimates, the SOC criterion becomes $-C1+B2/(1+p) + \tau B2(p.r-1)/(1+r)^2(1+p)>0$. It is easy to verify that the SOC criterion with the indirect revenue effect taken into account is equivalent to the STP criterion specified above.

Bradford (1975) argued that for projects whose costs displace investment in the same proportion as the benefits induce investment, the appropriate discount rate is the STP rate with no need to shadow price benefits or costs. However, his result depends upon two critical assumptions: first, that the private sector behaves myopically so its saving is not governed by optimizing behavior but rather by a simple rule of thumb whereby a constant proportion of (disposable) income is saved independent of the rate of return; and second, that investments in the private sector are not feasible options for the government, because otherwise scarce resources should be invested in such projects rather than in any project that can pass muster only at the STP rate. Even if private sector investments are off limits for the government, whenever there is public debt outstanding debt reduction is always an option and the rate of return on debt reduction is the SOC rate.

Estimating the SOC rate for the United States

The SOC rate is a weighted average rate that takes into account both the displacement of capital and foregone consumption, and in an open economy the use of foreign funds. The general expression for the SOC rate in a multi-sector economy with different effective rates of tax on capital in each sector, and with different rates of personal income tax on different groups of savers, is:

$$SDR=\sum\beta_i r_i+\sum\theta_j p_j+\alpha f \qquad (1)$$

Where:

$$\sum\beta_i+\sum\theta_j+\alpha=1 \qquad (2)$$

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Given that:

β_i =proportion of funds from increased savings of group i

r_i =marginal rate of time preference, typically after-tax real rate of return, as perceived by group i

θ_j =proportion of funds from displaced investment in sector j

p_j =marginal rate of capital productivity in sector j in home country

α =proportion of funds from incremental foreign funding

f =marginal cost of incremental foreign funding

While the SOC is conceptually straightforward, it is empirically challenging to arrive at a reliable estimate; not only must rates of return on alternative sources of funds be estimated, so must the proportions of funding drawn from each source.

A reasonable estimate of the opportunity cost of displaced investment is the pre-tax rate of return on capital in place.[6] National Accounts data can be used to estimate annual rates of return on reproducible capital (consisting of residential and non-residential structures, machinery and equipment, and inventories) as the ratio of the total income accruing to capital divided by the stock of capital. Rates of return estimated this way tend to exhibit low volatility, unlike financial rates of return, primarily because capital is measured at replacement cost rather than market prices (see Jenkins and Kuo 2010). A major advantage of using national accounts data is that the estimated rate of return encompasses all sectors of the economy and all forms of reproducible capital and is thus likely to provide the best estimate of the rate of return that the economy as a whole will forego when private investment is displaced.[7]

There are several challenges involved in estimating such a rate of return however. They include: how to separate the return to capital from the return to labor in unincorporated businesses; how to reliably separate payments to

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[6] Under competitive conditions and constant returns to scale the rate of return to capital in place will equal the marginal productivity of an increment to capital.

[7] Some have argued that the rate of return on real return bonds (TIPS) would provide a market-based measure of the risk free rate of return, which could then be grossed up by adding the various taxes that apply to capital. If TIPS yield 3% and capital income is taxed at 35%, the implied pre-tax rate of return on "risk-free" capital would be in the order of 4.6%. Quite apart from whether this provides a reasonable estimate of the risk-free economic opportunity cost of private investment displaced, it would not be appropriate for the government to use a risk free rate as the discount rate unless all project specific risk could be eliminated by pooling and spreading. Bond rates of course are a part of rates that make up our opportunity cost of capital.

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unimproved land from the return to capital; how to determine appropriate rates of economic depreciation for the various capital types; and how to determine what proportion of the measured return to capital (GNP minus labor compensation) reflects monopoly profits that should not be fully attributable to capital. In this paper we will have to rely on a less than fully comprehensive estimate of the rate of return to capital. Poterba (1999) estimated an average pre-tax rate of return in the U.S. non-financial corporate sector of 8.5% over the period 1959-1996. His estimates are based upon an improved methodology for determining the replacement cost of corporate capital. We will use this estimate as our baseline measure of the opportunity cost of displaced investment.

The consumer rate of interest is usually calculated as a group's after-tax rate of return, but for some groups (e.g. negative savers) it may be better approximated by the real interest rate on credit cards and other debt. Since the aggregate household sector is a net saver, a reasonable estimate of the marginal cost of foregone consumption is the pre-tax rate of return to capital net of all taxes on income from capital. Applying the corporate, property and personal tax rates to Poterba's 8.5% estimate of the pre-tax rate of return gives an after tax rate of return of approximately 3.5%. We will use this as our baseline estimate of the opportunity cost of postponed consumption.

Under certain conditions the average cost of foreign funding can be approximated as the rate of return that foreign investors earn on the capital invested in the country net of all taxes paid to the host government. If the supply price of foreign funding is upward sloping, the average cost will understate the marginal cost. If the withholding tax corrects the divergence between average and marginal cost, the marginal cost of foreign funding will be the rate of return to capital net of corporate and property taxes but gross of withholding taxes. Assuming a pre-tax rate of return of 8.5% and a combined corporate and property tax rate of 35%, the implied marginal cost of foreign funding is approximately 5.5%.

According to the SOC approach the marginal source of funding for all projects is the capital market, thus keeping the issue of tax reform separate from project evaluation. If a particular tax is being proposed to finance a particular project, the revenue from the tax could be used to pay down the debt instead of funding the project, so an alternative use of funds for any project is to pay down the debt.[8] Comparing the benefits from a proposed project to the benefits of debt reduction using the same funds (a comparison which is equivalent to the SOC criterion) ensures a level playing field for all projects, and avoids situations where a project is judged to be worthwhile solely on the merits of the efficiency of the tax intended to fund the project (Burgess 2011). Thus, the capital market should

[8] With the assumed benefit of debt reduction being a tax cut in the following period. For a more detailed discussion, see Burgess 2011.

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appropriately be evaluated as the marginal source of funding for all projects, even if a project is funded by a tax.

The weights that enter the SOC formula reflect the proportions of an incremental dollar of funding that is obtained from each source when funding is drawn from a well functioning, but distorted capital market. Harberger (1969) and Sandmo-Dreze (1971) show that these weights can be expressed in terms of the rate of return elasticities of supply and demand for each source and the proportions of existing funding drawn from each source. Estimates of the elasticity of demand for investment spending on fixed capital with respect to the cost of capital typically range from -1.0 to -0.7 (Department of Finance Canada 2008; Gilchrest et al. 2007), while estimates of the compensated elasticity of supply of indigenous saving with respect to the after tax rate of return are in the range from 0.1 to 0.2[9]

The elasticity of supply of foreign funding with respect to the rate of return is more problematic. Some would argue that this elasticity is close to infinite given the high degree of capital market integration, but it is crucial to recognize that what is relevant is the responsiveness of the net supply of real capital from abroad with respect to the real rate of return offered to attract this capital. If incremental funding for a project drives up the rate of interest it will crowd out some foreign direct investment as well as attract additional foreign portfolio investment. The net supply of real capital from abroad is the sum of these two competing effects. Burgess (2010b) shows that the SOC formula can be re-written in a way that does not depend (directly) upon an estimate of the elasticity of supply of external funding but instead upon an estimate of the "saving retention coefficient." Given an exogenous shock to indigenous saving, the saving retention coefficient is a ratio of the proportion of the indigenous savings increase that is invested within the country to the proportion of the savings increase that is invested abroad. Beginning with the widely cited paper by Feldstein and Horioka (1980), saving retention coefficients have been estimated by numerous researchers. The saving retention coefficient for OECD countries has been estimated to be in the range of 0.5 to 0.7 by Helliwell (1998). Since the U.S. is the largest OECD country, and larger countries have more market power, they will tend to have larger saving retention coefficients. At the same time, national saving and investment rates have become increasingly

[9] The compensated elasticity of supply of saving with respect to the after tax rate of return is the product of the elasticity of inter-temporal substitution and the proportion of wealth that is consumed. The elasticity of inter-temporal substitution must be non-negative but Hall (1988) could not reject the hypothesis that it was zero. Attanasio and Weber (2010) review the literature and report estimates from reputable studies of 0.67 and higher. They perform simulations with an elasticity of inter-temporal substitution in the range from 0.25 to 0.5. The implied range of values for the compensated elasticity of supply of saving is less than this.

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decoupled in recent years due to globalization. In light of these considerations a reasonable estimate of the saving retention coefficient for the U.S. is 0.6, with an upper bound of 0.67 and a lower bound of 0.5.

Burgess (2010b) shows that the SOC rate can be written as the following function of the relevant rates of return (opportunity cost of displaced private investment p, opportunity cost of postponed consumption r, and marginal cost of incremental foreign funding r*) the (compensated) elasticity of supply of indigenous saving e, the elasticity of demand for investment n, the proportion of investment that is financed by indigenous saving S/I, and the saving retention coefficient SRC:

$$SOC = \{p - (e/n)(S/I)r + ((1/SRC) - 1)f\}/D \tag{3}$$

Where:

$$D = -(e/n)(S/I) + 1/SRC \tag{4}$$

Using the estimates for the rates of return p, r and f identified above, the elasticity values $e = 0.2$ and $n = -1.0$, an assumed ratio of indigenous saving to investment S/I equal to 0.9 (which implies that 10% of private investment is financed from abroad), and a saving retention coefficient SRC equal to 0.6, the implied estimate of the SOC rate is 7.0% (which matches one of the two base-case rates recommended by the OMB for regulatory analysis, the other being 3%, see US OMB 1992; 2003). The implied proportions of an incremental dollar of funding that is obtained from displaced investment, postponed consumption, and incremental foreign funding are 0.54, 0.10, and 0.36 respectively.

It is possible that the benchmark estimates of the rates of return are biased upward or downward.[10] The weights indicate the extent to which the SOC rate will change in response to a change of one percentage point in the respective rate of return. For example, if the opportunity cost of displaced investment is underestimated by one percentage point the SOC rate will be underestimated by 0.54 percentage points, whereas if the opportunity cost of postponed consumption is underestimated by one percentage point the SOC rate will be underestimated by 0.1 percentage points.[11]

[10] For example Harberger (2010) makes the case that the pre-tax rate of return on investment is at least 10%. On the other hand, it could be argued that Poterba's estimate of 8.5% is biased upward because it pertains to the corporate sector only and ignores residential capital, which is more lightly taxed.

[11] McGrattan and Prescott (2003) estimate that the real after tax rate of return on U.S. reproducible capital averaged approximately 4% over the period 1880-2002.

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The table below (Table 1) shows the sensitivity of the SOC rate to alternative values of the saving retention coefficient and alternative values of the elasticity parameters e and n. If plausible ranges for e are 0.1 to 0.2 and plausible ranges for n are -0.7 to -1.0 it is conceivable that the ratio could be as low as .1 and as high as .28. It is also possible that the saving retention coefficient could be as high as .67 or as low as .5. The results indicate that the implied SOC rate is in the range from 6.6% to 7.3%. Finally, the ratio of S/I could be as low as .8 but the implied SOC rate is only mildly affected by this change. It seems reasonable to conclude that an appropriate range of values for the SOC rate for the U.S. economy is a lower bound 6% and an upper bound of 8%.

Some have argued that the SOC rate obtained from national accounts data will be biased upward because it contains a risk premium that represents necessary compensation for bearing risk (Boardman et al. 2010). A dollar of foregone investment constitutes a well-diversified portfolio of assets in all sectors of the economy. This rate of return will be well approximated by the average rate of return on this broad mix of capital over a sufficiently long time period to encompass business cycle swings, and it may contain a premium to compensate risk-averse investors for bearing any non-diversifiable risk. If so, the "risk free" SOC rate will be somewhat lower. However, unless the project adds less risk to the aggregate portfolio than what is foregone on the private investment displaced the appropriate discount rate should include the risk premium that is embedded in the SOC rate.[12]

Table 1: SOC Rate for the United States

SRC	e = 0.1, n = -1.0	e = 0.2, n = -1.0	e = 0.2, n = -0.7
0.5	6.9%	6.7%	6.6%
0.6	7.1%	7.0%	6.7%
0.67	7.3%	7.1%	6.9%

A frequent point of criticism regarding rates that arise from the SOC and related approaches is that they will materially reduce effects felt very far in the future. However, there is nothing inherently wrong with this. Nor will this mean that really large effects that occur in the future will necessarily be ignored. Suppose that unless corrective mitigation is taken now the worlds GDP will suddenly fall to zero in 100 years. The current world GDP is about $62 trillion. This will grow to $1192 trillion (constant dollars) in 100 years at a 3% annual real

[12] The analyst ideally should adjust for risk where the risk level is apt to be quite different from the average as is, for example, done for the Capital Asset Pricing Model. Unfortunately there are few in any relevant betas calculated for public projects.

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rate. Assume that with the mitigation, GDP will continue to grow forever at 3%. The present value of the lost future GDP at year 100 will be $30 quadrillion, assuming infinite life for the world. When this is discounted at 7%, its present value today is $34 trillion. This is not a trivial sum to consider to place on the side of mitigating the future harm.

Time Preference and Ethical Rates

Time Preference Rates

There is recent interest in time preference and ethical discount rates. Time preference refers to a demonstrated behavioral economic preference for immediate or near-term benefits over future accruement, which skews economic decision-making towards near term benefits. There is evidence that time preference rates do not correspond with the SOC rates. Evidence about the divergence of rates also suggests that the use of individuals' rates make choices practically difficult. Frederick et al. (2002) suggest that people have different discount rates for different activities and contexts. Thus rates individuals might feel to be most appropriate for application to government social policy analyses might differ significantly from the rates they use in their own investment or consumption decisions. In addition, surveys of rates of time preference are so varied that no single rate seems possible (Frederick et al.). More importantly there is no compelling rationale or motivation for using such rates even if available, since their use would result in a loss of efficiency and no clear gain in equity.

Recent work by Weitzman (1998; 2001) uses the opinions of economists about rates to form a set of discount factors:

$$1/(1/r)^t \qquad (5)$$

Weitzman (2001) argues that it would be sensible to assume that each expert has an equal chance of knowing the "correct" social discount rate and thus we should compute the present value of a public project using each individual expert's discount rate, and then compute an average of these present values. One can then back out the implied social discount rate.[13] Weitzman fits a gamma distribution to

[13] Weitzman (2001) notes: "What is the expected value today of an extra expected dollar at time t? It should be the expected present discounted value of a dollar at time t, weighted by the 'probability of correctness' or the 'probability of actuality' of the rate at which it is being discounted" (264). Weitzman infers that the probability that an individual expert is "correct" is given by the distribution of responses to a survey he conducted of 2,160 Ph.D.-level economists.

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the distribution of rates implied by the discount factors as suggested by the sample of economists. These rates are necessarily hyperbolic due to the divergence of rates. However, the gamma distribution over-weights the lower rates in his sample, significantly overestimating the frequency density of those with rates between 0% and 2% (see Weitzman 2001, Figure 1); this leads to rates that are too low, especially for longer time periods. When Weitzman's data is used to calculate actual discount factors and a rate extracted that represents the average rate the result is rates for every time period higher than calculated by Weitzman (Long et al. 2011).

There are several other objections to using Weitzman's results. First, economists as a general class are unlikely to be experts on the discount rate. Weitzman assumes an equal probability of each economist being correct (a uniform distribution); however, there is no reason to assume this sample of experts consists of the most knowledgeable people, or that their opinions should have equal weight. Further, in using a sample of discount factors (the present value calculation for different people) one will necessarily find social rates to be hyperbolic and find very low rates for projects in the far future as the rates will asymptotically approach the lowest rate in the sample.[14] Third, the spread of rates is disconcertingly wide. Even when Weitzman restricts his sample to only fifty eminent economists, their opinions as to an appropriate discount rate for global warming mitigation policies (with all benefits and costs converted into consumption equivalent real dollars for each year) still range from 0% to 15%. Even greater spreads have been found by Frederick et al. (2002). Finally, there is little underlying rationale rooted in economic theory for using these rates.

Ethical Rates

The manner in which BCA addresses intertemporal comparison is highly significant to project outcomes, as well as highly controversial philosophically. Some argue for a zero discount rate (i.e. no discounting of future benefits and costs) on philosophical and/or economic grounds (Parfit 1992; 1994; Pearce and

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From the survey responses, Weitzman finds that the distribution of the preferred discount rates roughly corresponds to a gamma distribution with a mean of 3.96% and standard deviation of 2.94%. Assuming a gamma distribution, Weitzman derives an implied effective discount rate of $m/(1+ts^2/m)$, where m is the mean, s^2 is the variance, and t is the number of years in the future when the benefit is to be received (or costs paid).

[14] The US OMB (1992) recommends against time varying discount rates on the grounds that it results in time inconsistency and that it is not ethically attractive. However, time inconsistency and hyperbolic rates for individuals appear to arise from uncertainty and risk (Farmer and Geanakoplos 2009). Once risk is accounted for, no time inconsistency exists and individual rates are constant, i.e. exponential.

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Turner 1989; Plater et al. 1998; Schultze et al. 1981) (see Goodin 1982 for an even-handed discussion of the limitations of discounting in policy analysis). Though it is commonly accepted that *money* should be discounted, both due to time preference and the investment value of money, the discounting of life and health (as is done in many social policy BCAs) is disputed (Sunstein 2007). Philosophers and legal scholars often question such discounting on ethical or legal grounds (e.g. Cowen and Parfit 1992; Revesz 1999; Shapiro and Glicksman 2003, Ackerman and Heinzerling 2002; 2004). This concern is addressed by the Principle of Intergenerational Neutrality (Sunstein 2007), which holds that members of any particular generation should not be favored over members of any other. This principle is in fact a core tenet of benefit-cost analysis (Zerbe et al. 2010), and does not repudiate discounting life and health values.

A significant amount of disagreement about rates arises from those who wish to impose special conditions on particular projects. The most common candidates are health and life. The arguments center around considerations that lives or pain or other human health-related goods have equal value regardless of when they are incurred. This in a sense is true of virtually all goods. The capital penalty for avoiding the more productive investment is not avoided by this consideration and there is no sound reason to adjust discount rates for heath and lives. The standard SOC criterion assumes that benefits are "just like income." If the benefits are not just like income there will be indirect revenue effects to include along with the "willingness-to-pay" (WTP) estimates of benefits, and they will be positive or negative depending upon the project. The appropriate discount rate remains the SOC rate. One might appropriately consider rates below the SOC rate for projects whose benefits are likely to induce private investment to an unusual extent, and conversely consider rates higher than the SOC for projects whose benefits are purely consumptive. However, these sorts of effects will be expensive to determine in many cases and could result in a ménage of various rates.

Conclusion

The SOC approach suggests discount rates in the range of 6%-8% given the current state of knowledge and data. The SOC approach is consistent with the main alternative approaches to determining discount rates but it is easier to implement because (unlike the shadow price algorithm) it requires no shadow pricing of investment and (unlike the MCF criterion) it applies a single discount rate to all benefits and costs. Rates that are time varying are not consistent with the SOC unless the parameters that determine the SOC change. Adjusting rates for future benefits to account for a decline in the marginal utility of income is also

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inconsistent with the SOC. If the current generation wishes to subsidize or penalize future generations these sentiments can be expressed directly through the values given to future costs or benefits. The use of very low rates, such as found by Weitzman's experts and independently assumed by Stern (2007), seems to be a way to account for the risk of extreme damage rather than a desirable adjustment to rates. This sort of adjustment should take place through determining the values of benefits and costs and not through the adjustment of discount rates. That is, where the current generation has moral values that apply to future generations these should be counted in terms of WTP at present and not incorporated into the discount rate. To use a lower discount rate than the SOC rate for long-term projects is to either transfer wealth from the present generation to the future at greater cost to the present generation than necessary, or to leave future generations worse off than they would be without the project. Sunstein (2007) takes the correct stance when he recommends treating all generations the same.

The method by which to treat this problem is to count present intergenerational equity concerns in terms of the current populations' WTP for such a moral value instead of into the discount rate. An example is presented in Zerbe (2004). This provides an effective means to address equity concerns without having to adjust the discount rate used in the analysis.

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TAB 12

The Most Appropriate Discount Rate

David Burgess

Richard O. Zerbe

Abstract

The social opportunity cost of capital discount rate is the appropriate discount rate to use when evaluating government projects. It satisfies the fundamental rule that no project should be accepted that has a rate of return less than alternative available projects, and it ensures that worthy projects satisfy the potential Pareto test. The social time preference approach advocated by Moore et al fails to satisfy either of these criteria even in the unlikely case that the private sector behaves myopically with respect to a project's future benefits and costs.

The use of the social opportunity cost of capital (SOC) discount rate is justified by a simple and powerful rule: **no project should be accepted if its return is less than the return available on alternative projects. This rule is as basic to economics as one that requires the analyst to take into account opportunity cost generally.** The use of the social time preference (STP) rate advocated by Moore et al (2013) violates this rule, and it also fails to ensure that acceptable projects produce potential Pareto improvements. In addition, the principles and standards guidelines state clearly (pp. 247, 281, 413-418) that matters that can be separated from inclusion in the discount rate (such as the marginal utility of income) should be separated, which is not done by Moore et al. Thus, concerns about underestimating environmental values in the distant future should not be addressed by lowering the discount rate. A better approach, and one endorsed by the Principles and Guidelines (Farrow and Zerbe, 2013, pp. 413-418), is to ensure that the estimates of these future values accurately reflect willingness to pay. There are sound reasons why the standard discount rate advocated by the Office of Management and Budget, and supported by our own work, is 7% rather than the 3.5% rate advocated by Moore et al (2013).

We understand the appeal of the argument for using the STP rate. It supposes that one should keep investing in available projects as long as the rate of return is above the STP rate (assumed to represent an appropriately weighted average of the rate at which individuals are willing to postpone current for future consumption). In the absence of capital income taxes this rate will eventually be reached as we move down a demand curve for capital using up high return projects. However, eventually may be a very long time as there are limits on the available supply of funds at each point in time, and labor force growth and technological change are both shifting the demand curve for capital to the right. In the meantime, until these investment opportunities are fully exploited, each project should be assessed relative to the best alternative project foregone.

Moore et al (2010) derive an estimate of the social rate of time preference from the Ramsey (1928) formula $STP = \delta + g\varepsilon$, where δ is society's "pure" rate of time preference (i.e. the rate of return society needs to forego a unit of consumption today when current and future consumption levels are equal), g is an estimate of the expected rate of growth of per capita consumption, and ε is an estimate of the (absolute value of the) elasticity of the marginal utility of consumption. Their preferred estimate of the STP rate for the United States is 3.5%. This is based upon an estimate of the pure rate of time preference of 1.0%, a prediction that per capita consumption will increase by 1.9% per year, and an estimate of the elasticity of marginal utility of consumption of 1.35.

But there is much disagreement among leading economists about the appropriate values for these parameters. Stern (2006) assumes that δ is equal to 0.1 based upon the small probability that society as we know it will not survive. By contrast, perhaps based upon estimates of individual rates of time preference, Nordhaus (2007) assumes a value for δ equal to 3.0. If the social rate of time preference is constructed as an appropriately weighted average of individual rates of time preference it seems that the individual rates of time preference span a wide range. Indeed, it is very difficult to isolate individual's time preference rates, let alone the joint distribution of project valuations and time preference rates, which is probably impossible to estimate.[1] In a broad survey of empirically elicited discount rates, Frederick et al. (2002 Table 1) find spectacular disagreement among dozens of studies that purport to be measuring time preference—from annual discount rates of negative 6% to infinity.[2] The median value listed in their Table 1 is 24% with an interquartile range of 8% to 158%.[3] Harrison et al. (2002) attempt to identify a distribution of time preference rates.[4] Based on experimental evidence, they find "that discount rates vary significantly with respect to several socio-demographic variables" (p.

[1] See Long, Zerbe Davis (2013). It is also challenging to identify individual's valuations of a project (whether they are expected to be alive or dead in year *t*). Since this challenge already exists for traditional benefit-cost analysis, we do not further discuss these empirical challenges, despite their importance.

[2] See also Anderson and McGugerty, (2009).

[3] They note: "[Table 1] reveals spectacular disagreement among dozens of studies that all purport to be measuring time preference. This lack of agreement likely reflects the fact that the various elicitation procedures used to measure time preference consistently fail to isolate time preference, and instead reflect, to varying degrees, a blend of both pure time preference and other theoretically distinct considerations, including: (a) intertemporal arbitrage, when tradable rewards are used; (b) concave utility; (c) uncertainty that the future reward or penalty will actually obtain; (d) inflation, when nominal monetary amounts are used; (e) expectations of changing utility; and (f) considerations of habit formation, anticipatory utility, and visceral influences" (p. 389)

[4] Subsequent studies by Chapman (2003) and Groom et al. (2005) provide compilations of recent literature on time preference and discounting, yet do not suggest a method for identifying a social discount rate.

1606). In particular, they find that discount rates are significantly lower for those with more education or who are unemployed and higher for those who are retired (controlling for categorical age indicators) or who believe they are credit constrained. These results suggest the possibility of correlation between project benefits and time preference rates for some projects that benefit particular demographic groups.[5] An attempt to take into account individuals' differences in time preference rates will lead to policy regret as shown by Long, Zerbe and Davis (2013). They provide an example in which if individual rates are used a project that has a negative net present value, but ten years hence the project produces positive net benefits and therefore passes the Kaldor-Hicks potential compensation test.

The mean discount rate found in Harrison et al. (2002) was 28%, well above market rates of interest. They note: "despite our extensive attempts to encourage credibility, the subjects might have doubted that we would actually follow through on the payments" (p. 1613). Thus, their estimate of a time preference rate may be biased upwards by incorporation of a risk premium of some unknown amount. Furthermore, variation in this risk premium by socio-demographic characteristics could have generated the observed variation in discount rates, even if there is no variation in pure time preference rates. Frederick et al. (2002) conjecture that "(i)f these confounding factors were adequately controlled, we suspect that many intertemporal choices or judgments would imply much lower—indeed, possibly even zero—rates of time preference" (p. 389).

With respect to the rate of growth of per capita consumption, the Moore et al prediction that per capita consumption will increase by 1.9 percent a year seems particularly optimistic. Stern (2006), for example, assumes that g is 1.3, and Dasgupta (2008) believes that g is trending downward toward zero. Finally, respected economists have come to wildly different conclusions about the appropriate value for the elasticity of the marginal utility of consumption. Stern (2006) and Nordhaus (2007) assume that ε is equal to 1.0, but Dasgupta (2008) argues that the appropriate value for ε is at least 3.0. All this illustrates the difficulties that one encounters when trying to produce a credible estimate of the public sector discount rate without using data on the performance of the actual economy.

Following earlier literature on the STP approach, Moore et al propose to take into account any private investment that is displaced by public investment using a shadow price that converts a dollar of private investment into its contemporaneous "consumption equivalent". However the concept of a shadow price of capital applied to multi-period projects is predicated on the

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[5] For a broader (but still partial) review of findings on time preference heterogeneity, see the many references Frederick et al, (2003) and in, Anderson and Gugerty (2009).

dubious assumption that the private sector behaves myopically with respect to the project, following a simple (Keynesian) rule of saving a constant proportion of any change in disposable income that arises period by period on account of the project. For projects with multi-period costs the methodology behind the STP approach is invalid if the private sector behaves rationally and has the same information about the project's benefits and costs as the policy maker.[6]

In the end, Moore et al conclude that calculating the appropriate shadow price of capital (and the appropriate marginal rate of return in the private sector) is essentially irrelevant on the grounds that most, if not all, public investment is financed by (income) taxes that primarily impact consumption rather than investment simply because consumption is a much greater proportion of the economy than investment. The STP approach then becomes a license for the government to undertake any project whose present value of benefits minus costs is positive when discounted at the STP rate despite the availability of projects in the private sector that offer significantly higher expected rates of return.[7]

The authors claim that the SOC approach recommended by Burgess and Zerbe (2011) and Zerbe (2011), where (constant dollar values of) benefits and costs are discounted at a rate reflecting the economic opportunity cost of borrowed funds is "not favored by most interested economists", and is in any event "conceptually incorrect". With respect to the first point, we

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[6] For further details see Burgess (2013b).

[7] It should also be mentioned that the financial data that Moore et al use to estimate the marginal rate of return of 6.79% depends upon assumptions about the aggregate debt/equity ratio, the inflation rate etc., and it is highly sensitive to business cycle swings (because capital is valued at market prices rather than at replacement cost). It is also less comprehensive than desired, i.e. it does not reflect the historical average performance of capital in the economy as a whole. A better estimate of the real rate of return to capital in the private sector uses national income accounts data. See Jenkins and Kuo (2010).

do not feel that the appropriate social discount rate is to be derived from a poll.[8] With respect to the second point, the authors make no attempt to explain why (in their view) the SOC procedure that Burgess and Zerbe (2011) propose is "conceptually incorrect".[9] Indeed, they make no attempt to address the problems with the STP approach that we identify. The only criticism of the SOC approach that they present is that the assumption that the marginal source of funding for all projects is the capital market (rather than an increase in taxes) is inappropriate because if it were true the level of outstanding debt would explode. But this is nonsense: it mistakenly equates a marginal source of funding with an average source. The reality is that the agency of government that sets tax rates is different from the agency that approves project expenditures. Because project expenditures are typically under-estimated, government borrowing becomes the means for bridging the funding gap. The recent alarming increase in the debt/GDP ratio in the U.S. is prima facie evidence that the level of outstanding government debt is NOT set independently of project expenditures that are then all financed by taxes.

While it is true that certain types of government expenditures- those that provide pure public goods rather than marketable private goods- must **ultimately** be financed by taxes, many projects are self-financing (i.e. they require no tax increase) because they generate sufficient revenue via user fees or from the sale of their output. Projects that are financed ultimately by taxes are typically financed **initially** by borrowing with taxes deferred to better coincide with when benefits are received. Treating the capital market as the marginal source of funds is a

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[8] The authors do not list these interested economists. They cite Cole, a lawyer, inappropriately as an authority as follows: "Indeed, Cole (2010), originally a member of the Scientific Committee reviewing these principles and standards notes that "not one of those three [commissioned white papers] supports the high discount rates recommended in Professor Zerbe's report." This is incorrect. Only one paper was commissioned to address directly the issue of the discount rate and this was the Burgess paper. Other papers briefly addressed this issue in the context of broader issues but simply cited other literature. Cole resigned from both the Scientific Committee and indeed from the Benefit-Cost Society reportedly (telephone call between Zerbe and Cole) as a result of our acceptance of the Burgess view. Cole's reaction was that of an advocate committed to low discount rates, not a scientist; such an approach is ascientific.

[9] The Burgess and Zerbe view has been presented more formally by Burgess (2013a)

convention that allows project evaluation to be separated from tax policy. Rather than a specific project benefiting from, or being disadvantaged by, the use of a specific tax, all projects are evaluated on a level playing field.

More fundamentally, the authors fail to recognize that the SOC criterion measures the impact of the project on the government's budget when the private sector is kept at pre-project utility. Conceptually, the private sector is kept at pre-project utility by the government inducing the private sector to willingly postpone consumption and/or divert saving from private investment into government bonds to finance the project's costs and, whether through ordinary market transactions or (in the case of pure public goods) through (lump sum) taxes, appropriating the private sector's willingness to pay for the project's benefits. This is in contrast with the STP/SPC criterion that purports to measure the project's impact on social welfare (measured at the present value of consumption discounted at the STP rate) when the government balances its budget in each period by collecting sufficient tax revenue to cover the project's cost in that period.

It follows that the appropriate measure of the SOC rate is the social opportunity cost of **borrowed** funds, not the social opportunity cost of funds raised by an increase in the income tax or some other broad based tax. Admittedly, It is empirically challenging to arrive at reliable estimates of the weights that enter into the SOC measure (i.e. the proportions of an increment of borrowed funds that displace investment versus consumption and, in an open economy, net exports), but the consensus of those who have looked carefully at the matter is that investment is much more sensitive to the rate of return than consumption or net exports, so the bulk of an increment in borrowed funds displaces investment.

If the private sector is as well informed about the project's benefits and costs as the policy maker it is in a matter of indifference whether one chooses to measure the project's impact on the government's budget (present value of government revenue discounted at the SOC rate) holding the private sector at pre-project utility or to measure the project's impact on social welfare (present value of consumption discounted at the STP rate) when the government maintains inter-temporal budget balance. However, the STP procedure fails to measure the project's impact on social welfare with the government's inter-temporal budget balanced. A recent paper by Liu (2011) shows the conceptual flaw in the STP procedure applied to projects with multi-period costs. The problem arises because the STP procedure assumes that the shadow price of capital for any project is the same no matter when the project's expenditure occurs. Thus a dollar of project expenditure that occurs in period 0 is supposed to have the same contemporaneous consumption equivalent as a dollar of project expenditure that occurs in any other period. For a multi-period project, expenditure in each period is treated by the private sector as an unanticipated shock even though the time stream of expected project expenditures is well known to the policy maker. While the notion that the private sector behaves as a rational, forward looking utility maximizing agent is certainly contestable, the myopic behavior represented by a constant marginal propensity to save in the STP approach is even more problematic.

Even if one were to accept the constant marginal propensity to save assumption of the STP approach, a simple argument shows that the STP criterion fails to ensure that scarce tax dollars are spent in the most productive way. Suppose that a project requires C0 dollars in period 0 and yields benefits worth B1 dollars in period 1, and that the private sector treats a dollar's worth of benefits just like a lump sum transfer of a dollar. According to the STP criterion the project is worthwhile if $B1\ (1\text{-}s + sV)/(1+r) - C0\ (1\text{-}s+sV) > 0$, where r is the STP rate, V is the shadow price of capital and s is the marginal propensity to save. A worthy project must increase the present value of the private sector's consumption stream discounted at the STP rate. The procedure assumes that the project's cost is financed by an increase in the income tax and a proportion represents displaced investment, which is converted into its consumption equivalent by multiplying by V.[10] Because the project's benefits are "just like income" a dollar of benefits has the same consumption equivalent as a dollar of costs. It is therefore unnecessary to apply a shadow price to any investment displaced or induced (because the conversion parameter for a dollar of costs is equal to the conversion parameter for a dollar of benefits). The project is worthwhile according to the STP criterion if net benefits are positive when discounted at the STP rate.

The problem with this result is that it ignores alternative uses of the tax revenue that yield higher returns. It is important to recognize that **these alternatives are available even if the government is unable to invest directly in the private sector** for political reasons as long as part of the private sector's wealth is held as government debt.[11] Suppose the funds collected for the project are used instead to reduce the outstanding government debt. Debt at the beginning of period 1 will be reduced by C0 dollars, which will "crowd in" C0 dollars of private

[10] An income tax is assumed to be equivalent to a lump sum tax in the STP approach because there is no accounting for the efficiency cost of the tax.

[11] Bradford (1975) and Lind (1982) rule out the rate of return in the private sector as the relevant opportunity cost for public investment whenever direct government investment in the economy is not feasible on political or other grounds, but they neglect the ability of the government to induce additional private investment through debt redemption.

investment and increase capital income tax revenue by $\tau\rho C0$ dollars, where τ is the capital income tax rate and ρ is the pre-tax rate of return (assumed to be exogenous). In addition, debt service costs will be reduced by r dollars so the government will be able to reduce the income tax in period 1 by $(1+r + \tau\rho)\ C0 = (1+\rho)\ C0$ dollars (note that $\rho(1-\tau) = r$) while maintaining inter-temporal budget balance. The private sector will prefer the project costing C0 dollars and yielding benefits worth B1 to spending the funds on debt reduction yielding benefits worth C0 $(1+ \rho)$ only if $B1/(1+\rho) > C0$. This is the SOC criterion. Thus the Moore et al approach fails to take into account the opportunity cost of funds, the most fundamental requirement of a correct approach.[12]

It is important to note that the above argument does not depend upon the existence of a capital income tax. Thus suppose the wedge between the STP rate and the rate of return to capital reflects a "defective telescope" whereby the representative individual's rate of impatience exceeds the social rate. If the rate of return in the private sector is ρ then government bonds must also offer savers this rate of return. So when the government uses a dollar of tax revenue to redeem a dollar of debt it will "crowd in" a dollar of private capital whether or not there is a tax on capital income.[13] Since the government's borrowing rate must equal ρ the tax increase of one dollar in period 0 will make possible a $1+\rho$ dollar tax cut in period 1 while holding the level of public expenditure fixed. The private sector will prefer a one dollar project yielding benefits worth B1 to debt reduction only if $B1 > 1+\rho$.

So far we have ignored inter-generational effects. For projects with effects that span many generations, Moore et al recommend a discount rate that declines through time. In our view the appropriate discount rate for any government project, whether or not it has inter-generational effects, is the SOC rate. While it is conceivable that the rate of return to capital in

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[12] Moore et al do not regard debt reduction as an alternative use of tax dollars. Debt problems are presumably solved by economic growth, not by diverting taxes to debt reduction. But debt problems arise because project expenditures exceed tax revenue. Since the cost of debt is the SOC rate and debt results because spending exceeds tax revenue, spending going forward should only be approved if it satisfies the SOC criterion.

[13] Government debt displaces private capital one for one only if the rate of return to capital in the private sector is exogenous. In the general (closed economy) case government debt will displace both private investment and consumption so the appropriate SOC rate is a weighted average of ρ and r.

the private sector may decline in the future, thereby lowering the appropriate SOC rate, there is no evidence that the rate of return to capital is trending downward at the moment. Until there is such evidence we recommend using a constant social discount rate in the range of 6% to 8% for all government projects.

It is worth emphasizing that discounting benefits and costs at the STP rate in an inter-generational context will result in some projects being accepted that fail the Kaldor-Hicks compensation test. In our simple example of a project that costs C0 dollars in period 0 and yields benefits worth B1 dollars in period 1, unless the project passes the SOC criterion it will not be possible for the project to make all generations better off. Thus to ensure that those currently living are not adversely affected the project must be debt financed. The debt is purchased by the current young generation who are owed principal plus interest. Suppose the project benefits the next young generation whose willingness to pay is B1. The debt that is issued to fund the project diverts saving from private investment that would yield a rate of return of ρ. If there is a capital income tax and government bonds are tax exempt the government can borrow at rate r, but it will also lose capital income tax revenue of $\tau\rho$. To compensate the current young generation the government must repay the debt they purchased with interest plus make up for the loss of capital income tax revenue (presumed to fund existing programs such as retirement benefits). The government can raise taxes on the next young generation by as much as their willingness to pay for the project's benefits before leaving them worse off. Therefore the project satisfies the K-H compensation test only if $B1 > C0\ (1+r+\tau\rho)$. This is the SOC criterion.

Conclusion: There is perhaps no issue in benefit-cost analysis more urgent than coming to some agreement, even if rough, on the appropriate discount rate to be used for government spending. Our hope is that the present article, and the recent article by Burgess (2013a), will contribute to this agreement. Our further hope is that Moore et al will come to agree with us.

The discounting procedure recommended by Moore et al is conceptually flawed. It fails to ensure that worthy projects represent the best available use of tax dollars, and it fails to identify projects that can produce potential Pareto improvements. They claim that it is wrong to treat the marginal source of funds for all projects as the capital market, and they continue to maintain that all projects should be viewed as tax financed rather than debt financed despite the obvious fact that this is not historical reality. They don't realize that treating the capital market as the marginal source of funds is merely a reflection of the fact that the SOC criterion looks at the project's impact on the government's budget holding the private sector at pre-project utility. If the project can result in an increase in the present discounted value of government revenue (discounted at the SOC rate) while the private sector is held at pre-project utility then the project is worthwhile undertaking.

In fact, the SOC criterion applies whether or not "Ricardian Equivalence" holds. If RE holds the private sector recognizes that deferring a (lump sum) tax increase to a future date to fund a project does not affect the worthiness of a project. Moore et al clearly believe that RE does not hold because they claim that it matters whether a project is (lump sum) tax financed or debt financed, and specifically that it will be easier to satisfy the STP criterion if the project is tax financed. Our point is that even if one could fool the public by the choice between tax finance and debt finance it would still be necessary to consider whether the use of scarce tax dollars on the project is superior to using those tax dollars to pay down the debt, and this comparison results in the SOC criterion!

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TAB 13

ECONOMIC ANALYSIS OF GAS-FIRED AND NUCLEAR GENERATION RESOURCES

1.0 SUMMARY

This paper outlines the results, methodology and data used to determine the requirements for base load and peaking resources in the Integrated Power System Plan (the "IPSP" or the "Plan"). The results are similar to those presented in the Supply Mix Advice report released December 9, 2005.

2.0 INTRODUCTION

An efficient power system requires a balance of resource capabilities to meet the daily and seasonal requirements for capacity, energy, operating reserve, and other services, and do so in the most economic manner. This balance of resource capabilities will require a proper allocation of supply between baseload, intermediate and peak supply components. As discussed in the original Supply Mix Advice report, these resource components can be defined as follows:

A baseload plant generally has higher fixed costs and has a relatively low portion of its total costs as variable costs, such as hydroelectric and nuclear generators, for example. Its overall economics improve the more it is used as its high fixed cost is spread over a greater level of output. A resource with baseload capability is well suited for meeting the portion of load that exists much of the time, and for continuous operation at constant rates of production[1]. Some baseload resources, such as nuclear, require relatively long start-up and shut-down times and have limited ability to increase or reduce output in response to short-term variations in demand. Some types of hydroelectric, on the other hand, are typically much more capable of responding to short-term variations in demand.

[1] Exceptions to this generalization include wind power, run-of-the-river hydro, and some cogeneration. These resources are used whenever they are available, such as when the wind blows, when the river runs, or when steam is required (in the case of a cogeneration facility).

Peaking resources have the opposite characteristics of baseload plant, with fixed costs that are relatively low and variable costs that are high. Peaking resources are therefore attractive for meeting load that is present for a relatively small portion of the time. A peaking resource is capable of ramping up very quickly to meet brief spikes in demand throughout the day or night. Peaking generation is also capable of providing power and energy on short notice, for example taking up the "slack" resulting from an unexpected loss of another generation resource. Simple-cycle gas turbines ("SCGT") and hydroelectric with storage capability are examples of peaking resources.

Intermediate resources, as the name suggests, have characteristics that lie between the baseload and peaking plants. An intermediate resource is capable of increasing its output in response to daily demand swings. The morning and early evening rush hours are examples of such swings, and can account for changes of 5,000 MW or more within several hours. Coal-fired generation and combined-cycle gas turbines ("CCGT") are examples of intermediate resources that typically will have relatively higher marginal costs (fuelling) and greater flexibility than base load plants.

This report will analyze the economics of various generation resource technologies to estimate the proper allocation of supply between baseload, intermediate and peak supply components for the Ontario power system.

3.0 ECONOMIC EVALUATION METHODOLOGY

A method used throughout the development of the Plan, is to compare the costs of alternative generation resources on the basis of their Levelized Unit Energy Cost ("LUEC"). LUEC is the average cost of the energy produced from an electric power generator over its service life, considering all the costs in the lifecycle of the plant, including its construction, operation and fueling, and decommissioning costs. In the definition that the OPA has adopted, LUEC is the price (escalating at the rate of inflation) that would have to be charged for each MWh produced over the lifetime of a generator that would provide the revenue stream with the same present value as the direct costs of construction, operation and decommissioning of the plant.

For the calculation of LUEC of a project with construction cost, K (including financing costs as valued at the date of service start-up), annual energy production, Q, at real annual cost, C (including fuel, operations and maintenance valued in constant dollars of the year at service start-up) in each of the L years of service life, and real (net of inflation) discount rate of r, the LUEC is estimated as:[2]

$$\text{LUEC} = (K \times r / Q) \div \{ 1 - (1+r)^{-L} \} + (C/Q)$$

The LUEC is expressed in constant (real, net-of-inflation) dollars of the base year in which service begins, per Megawatt-hour of energy produced.

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[2] More generally, the LUEC may be estimated for a generator with annually varying capital modification cost, annually varying production cost and volume, and decommissioning cost

The calculation of LUEC involves accumulating the generator's discounted cashflow costs to a total present value (PV) of construction, operating and post-service costs, and then "averaging" that PV over the generator's total production.

The first step is to calculate the present value (PV) of the generator's lifecycle cost:

$$PV = \sum (\text{capital.cost}_m + \text{operating cost}_m + \text{capital modification cost}_m + \text{decommissioning cost}_m) \times \text{discount factor}_m$$

On the right-hand side of the above expression:
The costs may be expressed in terms of constant real dollars of a base year, or , alternatively,in terms of escalated dollars including inflation. With the discount factor correspondingly expressed in real or escalated terms, the present value result is identical.
The capital cost in the above formula is the cost of design, engineering, construction and commissioning, *excluding* the allowance for interest or other financing costs during construction. The operating cost includes the cost of fuel, routine maintenance, and administration for the generator. The sum $\sum$ of the annual products of capital cost and discount factor is used in a way that is analogous to the generator's *gross* asset value including the cost of financing during construction.

The second step is to calculate the LUEC as a "present value average" of the PV cost over the lifecycle energy production. This is done by dividing the PV into the "volume present value" of the generator's lifecycle energy production:

$$\text{LUEC} = PV \div \sum (\text{annual energy production volume}_n) \times \text{real discount factor}_n$$

In the above expression, the real discount factor (which excludes the effect of inflation) must be valued at 1 in the year of service start-up. The real discount factor$_n$ in year n is equal to the real discount factor$_{n-1}$ in year (n-1) divided by (1+real discount rate)
If the annual energy production volume has the same value Q each year, and if the real discount rate has the same value r each year, then

$$\text{LUEC} = (PV \times r/Q) \div [1 - (1+r)^{-L}] \}$$

The LUEC of a generator is sensitive to the amount of energy it produces. The more energy, the lower the LUEC, as the capital costs are spread over a larger amount of energy.

In addition, the value of the LUEC is sensitive to the discount rate: a higher (or lower) discount rate raises (or lowers) the LUEC just as higher (or lower) financing affects overall costs.

3.1 Need for a Discount Rate

As described in the previous section, a discount rate contributes to the determination of a project's net present value ("NPV"). The reason for discounting is to represent the generally-accepted proposition that a dollar in a future year is worth less than a dollar in the current year. Put another way, "People prefer to consume a given amount of resources now rather than in the future."[3] Accordingly, the present value of a stream of future cash flows is the sum of successively discounted yearly cash flows.

Different discount rates are used to evaluate private and public investments in the economy:

- Businesses use their own measures of Return on Equity ("ROE") or Weighted Average Cost of Capital ("WACC") after-tax rates to discount investment costs and private returns accruing to them on an after-tax basis in unregulated markets;
- Regulatory agencies allow utilities to earn a specified rate of return on capital, depending on the utility's deemed conditions of capital structure and risk;
- Households postpone some consumption in favor of savings, depending on interest rates on bank savings accounts, RRSPs, or other personal savings vehicles;
- Governments undertake (or mandate) projects of infrastructural, environmental, or health and safety enhancement in the wider public interest, assessing project merit in terms of the long-term return to current and future generations of society as a whole, using a Social Discount Rate ("SDR");

The resulting LUEC is expressed as a per MWh cost in constant dollars of the year of service start-up.

[3] by Moore, Boardman, Greenberg (p.75)

- In the Ontario Ministry of Finance paper, "The Social Discount Rate for Ontario Government Projects" (January 2007), P. Spiro recommends using 5% as the real SDR. This value is calculated based on estimates of Canadian corporations' Weighted Average Cost of Capital -- with an adjustment to represent corporate returns *before* deducting Ontario income tax, but *after* deducting Federal income tax.

3.2 Appropriateness of Social Discount Rate for the IPSP

SDR is normally applied to investments to serve the wider public interest, such as public infrastructure, or projects for environmental or health and safety enhancement. The benefits of such projects are widespread and cannot be restricted to any identified specified group of users. In the same way, such projects are not associated with "market returns" flowing to specified project owners. By contrast, business investments, which are evaluated through ROE and WACC rates, are designed to service specified customers, and yield the consequent market returns to the project's shareholders and creditors.

SDR is normally applied to projects whose effects include benefits, costs, and foregone opportunities that endure into the long-term and affect future generations. By contrast, business investments are usually designed to yield shorter-term benefits.

Electricity system-related investments, include transmission and distribution, and include renewables and Conservation funded by utilities, end-users and government. They have characteristics of both public and business investments.

The projects are generally undertaken in the wider public interest, and thus have characteristics of public infrastructural, environmental or health-related investments. As such, some of the benefits of such projects extend beyond specific services sold to identified customers, but are dispersed uncontrollably as societal benefits. Correspondingly, the project's financial value extends beyond the investor's returns, but includes also government tax revenues which are also a potential resource for public benefit.

The projects have long gestation periods, with much of the benefits yielded in the long-term and to future generations. In this way, such projects may be considered to require a wider range of criteria than that used for business decision-making.

The OPA uses a SDR for economic evaluation of the power system plan portfolio because it is assessing the portfolio of electricity-related projects in the public interest, taking into account infrastructural and environmental aspects with long-term implications for current and future generations.

3.3 OPA's Use of Social Discount Rate in the IPSP

The following summarizes the OPA's use of the SDR in the IPSP:

- The SDR reference value is 4% in real terms;
- For sensitivity analysis, 2% and 8% are used as alternative values for the real SDR;
- The same SDR is used to discount each cash flow cost of each existing and new supply- and demand-side facility in the Plan;
- A Plan which has a lower NPV cost is favoured over a Plan with a higher NPV cost assuming both plans meet Directive and system reliability requirements;
- Externalities are not monetized in the NPV system cost; and
- Income tax on the generator's profits is not included in the NPV of Plan costs.

3.4 Determination of the Value of Social Discount Rate for the IPSP

In determining the value of an SDR to assist in choosing between current economic benefits and long term economic benefits, the OPA considered the situation of an Ontario resident deferring current consumption in order to invest in an RRSP to provide for future consumption.

OPA estimated that a long-term Government of Canada bond providing a nominal 5 ½%-6% interest including 2% inflation, held for 6-25 years in an RRSP by an Ontario resident until retirement, yields a real after-tax return of 3 ½% - 4 ½% compounded annually. This means that the individual chooses to defer consumption in favour of gaining a net annual 3

½% - 4 ½% into the long-term. This is a reasonable proxy for an individual's Rate of Time Preference extending into the long-term, and a reasonable representation for the discount rate.

Accordingly, OPA has chosen its reference value for the real SDR as 4%. The 4% value is highly approximate[4], depends on specific assumptions, and is meant to represent the "aggregate" of individuals' Rates of Time Preference.

Due to the wide range of authoritative estimates for the SDR, it is prudent to examine the degree to which the economic preference for the recommended projects would be affected by SDRs of lower or higher value than the reference 4% real rate. Accordingly, where appropriate, the OPA tests sensitivity using 2% as a lower SDR value, and 8% as a higher SDR value.

3.5 Consistency with Ontario Energy Board's Direction

The OPA uses a "real" net-of-inflation discount rate applied to costs expressed in "real" dollars-of-base-year. The OEB's guidance is to use a discount rate applied to costs expressed in "dollars-of-the-year". With the appropriate discount rates, these two methods are completely equivalent, and provide identical NPV estimates expressed in dollars of a single base year.

For example, the OPA's practice of applying a "real" discount rate of 4% to "real" costs expressed in dollars-of-base-year produces exactly the same NPV estimate as does applying a "nominal" discount rate of 6.08% to costs expressed in "escalated dollars-of-the-year" including inflation assumed at 2%.

The OPA applies its discount rate to all applicable costs and savings associated with every existing facility and new project in the IPSP, and so satisfies the OEB's requirement that the NPV include all applicable costs.