PLAN ROBUSTNESS

1.0 INTRODUCTION

This exhibit discusses the approach of the Integrated Power System Plan (the "IPSP" or the "Plan") to meeting requirements across a variety of potential circumstances and presents results to demonstrate the Plan's robustness.

2.0 RESOURCE REQUIREMENTS

Q. How will the IPSP meet resource requirements?

A. The IPSP meets requirements through the combination of existing, committed and planned resources1. It does so by identifying specific priorities in the near term and developing options for the mid term. Examples of options and opportunities include:

- out-of-province purchases;
- taking advantage of greater success in capturing Conservation potential;
- greater availability of renewables such as bioenergy, solar and waterpower;
- the emergence of developing technologies such as fuel cells and gasification;
- greater use of existing technologies such as storage;
- the potential to redevelop existing contracts for natural gas-fired facilities;
- potential for expansion or conversion at existing sites; and
- the potential for greater flexibility around nuclear refurbishments.

The Plan will be updated periodically to address changes in circumstances. Examples of changes in circumstances include changes in forecast demand and forecast resource requirements, greater or lesser success in implementing planned projects, and changes in the availability of existing and/or forecast planned resources.

[1] Existing and committed resources as of June 1 2007 are summarized in Exhibit D-3-1. In addition to existing and committed resources, the Plan includes contributions from planned Conservation, renewable, natural gas-fired and nuclear resources. As described in Exhibit D-3-1, planned resources are those that are neither existing nor committed.

Given the above, the Plan is developed in recognition of - among other things - uncertainty, risk and alternative possibilities for meeting evolving resource requirements. The Plan is not a static forecast of future resource development, but is adaptable across a variety of circumstances.

The following paragraphs will outline several scenarios that are intended to illustrate a range of possible futures. The scenarios together illustrate the range of potential resource requirements over the planning horizon as well as how those requirements could be met. The capability of meeting requirements across a variety of potential futures is indicative of Plan robustness.

Q. How does the Plan propose to meet resource requirements under reference conditions?

A. Two ways of meeting Ontario's resource requirements over time and under a particular set of reference conditions are illustrated in Exhibit D-9-1. These variations of what is termed the "reference plan" are referred to as "Case 1A" and "Case 1B". Case 1A assumes the refurbishment of Pickering B, and Case 1B assumes that it is not refurbished.

Q. How does the Plan propose to meet resource requirements under conditions that differ from those assumed in Cases 1A and 1B?

A. Three cases were formulated to test how the Plan can be adapted to meet requirements under different conditions:

- Cases 2A and 2B: Higher load growth;
- Cases 3A and 3B: Higher Conservation; and
- Cases 4A and 4B: No development of northern renewables.

The purpose of analyzing the above cases is to determine what decisions are required and how soon they have to be made. The cases demonstrate that the Plan can respond

in the short term with the resources specified for the reference case, and that it will not be necessary to procure additional resources by 2010 if any of these cases becomes more likely.

Each case was developed for conditions in which Pickering B was assumed to be refurbished (the A cases) and for conditions in which Pickering B was assumed not to be refurbished (the B cases).

3.0 CASE 2

Q. Was a case of higher demand considered?

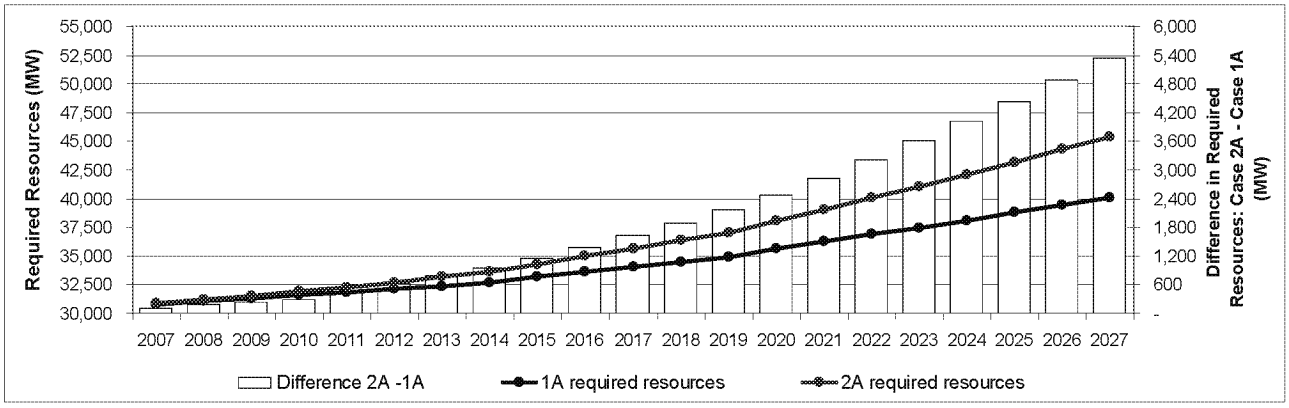
A. Yes. Cases 2A and 2B present a higher demand case where the annual average growth rate in peak demand was assumed to be 1.9% compared to the1.2% in the reference forecast. Figure 1 and

A. Table 1 illustrate that the total resource requirement (peak demand plus planning reserve) by 2015 is about 1,200 MW greater, and by 2027 is about 5,400 MW greater in the higher demand case than it is in case 1A. The largest increase in requirements in the higher demand case is seen to occur in the period beyond 2015. The difference between the two forecasts is approximately 4,500 MW and 25 TWh by 2027.

Possible Plan adjustments that can meet these cases are illustrated in Figure 2, Figure 3, Table 2, Table 3, Table 8, and Table 9. In both Cases 2A and 2B, it is seen that resource requirements can be met until about 2015 with the resources planned to meet reference load forecast conditions. Coal-fired generation would continue to provide insurance until the end of 2014 under the high load-growth cases. Beyond 2014, additional resources would be required. These additional requirements after 2014 are met with 1,200 MW of resources in 2016 growing to over 5,000 MW by 2027, including 3,000 MW of additional (for now) unspecified resources by 2027 as well as about 2,000 MW of additional natural gas-fired resources (relative to the cases developed for reference load conditions). Like Case 1B, Case 2B also requires additional bridging resources in the mid term as a consequence of the non-

refurbishment of Pickering B. The additional resources are required starting in 2016, and there is therefore no need to procure them by the end of 2010.

Figure 1: Comparison of Resource Requirements under Reference and Higher Growth Scenarios (MW)



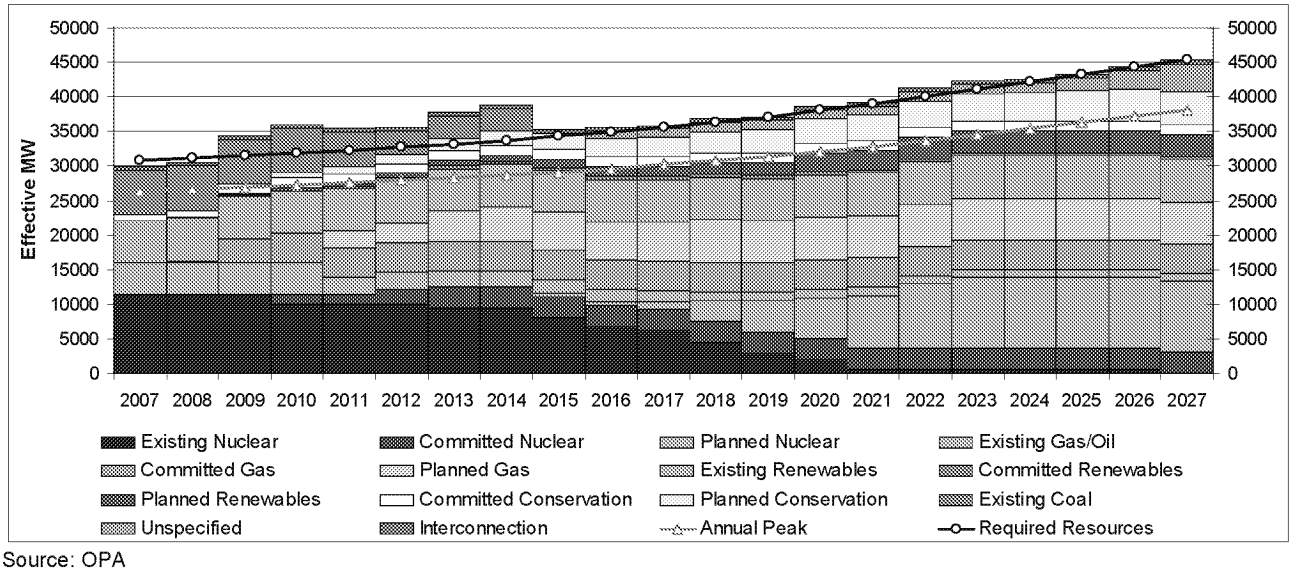
Source: OPA

Table 1: Comparison of Resource Requirements under Reference and Higher Growth Scenarios (MW)

MW	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
1A required resources	30,750	31,022	31,296	31,573	31,830	32,088	32,349	32,611	33,157	33,580	34,008	34,441	34,880	35,624	36,228	36,843	37,468	38,103	38,750	39,407	40,076
2A required resources	30,860	31,189	31,521	31,856	32,274	32,697	33,125	33,559	34,290	34,957	35,638	36,332	37,039	38,080	39,050	40,045	41,065	42,111	43,184	44,284	45,413
Difference 2A -1A	110	167	224	283	444	609	777	948	1,133	1,378	1,630	1,891	2,159	2,456	2,822	3,202	3,597	4,008	4,434	4,877	5,337

Source: OPA

Figure 2: Case 2A Cumulative Resources (Effective MW)



Source: OPA

Table 2: Case 2A Cumulative Resources (Effective MW)

Effective MW	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Existing Nuclear	11,419	11,419	11,419	9,879	9,879	9,879	9,363	9,363	8,050	6,686	6,170	4,487	2,792	1,911	515	515	515	515	515	515	0
Committed Nuclear	0	0	0	1,500	1,500	2,270	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040
Planned Nuclear	0	0	0	0	0	0	0	0	516	516	1,032	3,045	4,593	5,990	7,673	9,368	10,249	10,249	10,249	10,249	10,249
Existing Gas/Oil	4,578	4,578	4,578	4,578	2,473	2,473	2,308	2,308	2,004	1,897	1,691	1,236	1,236	1,236	1,236	1,105	1,105	1,105	1,105	1,105	1,105
Committed Gas	0	281	3,431	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267
Planned Gas	0	0	0	0	2,455	2,905	4,507	5,057	5,361	5,467	5,673	6,129	6,129	6,129	6,129	6,129	6,129	6,129	6,129	6,129	6,129
Existing Renewables	6,129	6,129	6,129	6,129	6,129	6,129	6,129	6,129	6,129	6,129	6,129	6,129	6,129	6,129	6,129	6,129	6,129	6,129	6,129	6,129	6,129
Committed Renewables	4	115	317	408	408	408	408	408	408	408	408	408	408	408	408	408	408	408	408	408	408
Planned Renewables	11	25	58	58	303	584	742	982	1,143	1,491	1,529	1,638	1,871	2,662	2,770	3,135	3,135	3,157	3,255	3,255	3,255
Committed Conservation	755	1,006	1,375	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407
Planned Conservation	0	0	0	755	1,084	1,413	1,741	2,070	2,398	2,614	2,878	3,146	3,358	3,560	3,722	3,884	4,043	4,206	4,354	4,583	4,811
Existing Coal	6,434	6,434	6,434	6,434	4,969	3,293	3,293	3,293	0	0	0	0	0	0	0	0	0	0	0	0	0
Unspecified	0	0	0	0	0	0	0	0	0	1,100	1,100	1,350	1,350	1,350	1,350	1,350	1,350	1,350	1,850	2,700	3,850
Interconnection	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	750
Annual Peak	26,376	26,657	26,941	27,228	27,585	27,946	28,312	28,683	29,059	29,625	30,201	30,789	31,389	32,000	32,815	33,651	34,508	35,388	36,289	37,214	38,162
Required Resources	30,860	31,189	31,521	31,856	32,274	32,697	33,125	33,559	34,290	34,957	35,638	36,332	37,039	38,080	39,050	40,045	41,065	42,111	43,184	44,284	45,413

Source: OPA

Table 3: Case 2A Cumulative Resources (Installed MW)

Installed MW	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Existing Nuclear	11,419	11,419	11,419	9,879	9,879	9,879	9,363	9,363	8,050	6,686	6,170	4,487	2,792	1,911	515	515	515	515	515	515	0
Committed Nuclear	0	0	0	1,500	1,500	2,270	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040
Planned Nuclear	0	0	0	0	0	0	0	0	516	516	1,032	3,045	4,593	5,990	7,673	9,368	10,249	10,249	10,249	10,249	10,249
Existing Gas/Oil	5,103	5,103	5,103	5,103	2,998	2,998	2,833	2,833	2,529	2,422	2,216	1,761	1,761	1,761	1,761	1,630	1,630	1,630	1,630	1,630	1,630
Committed Gas	0	281	3,431	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267
Planned Gas	0	0	0	0	2,455	2,905	4,507	5,057	5,361	5,467	5,673	6,129	6,129	6,129	6,129	6,129	6,129	6,129	6,129	6,129	6,129
Existing Renewables	8,258	8,258	8,258	8,258	8,258	8,258	8,258	8,258	8,258	8,258	8,258	8,258	8,258	8,258	8,258	8,258	8,258	8,258	8,258	8,258	8,258
Committed Renewables	5	331	1,158	1,415	1,415	1,415	1,415	1,415	1,415	1,415	1,415	1,415	1,415	1,415	1,415	1,415	1,415	1,415	1,415	1,415	1,415
Planned Renewables	16	36	81	81	855	1,260	1,729	2,335	2,692	3,278	3,380	3,837	4,129	5,599	5,746	6,247	6,247	6,276	6,411	6,411	6,411
Committed Conservation	755	1,006	1,375	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407
Planned Conservation	0	0	0	755	1,084	1,413	1,741	2,070	2,398	2,614	2,878	3,146	3,358	3,560	3,722	3,884	4,043	4,206	4,354	4,583	4,811
Existing Coal	6,434	6,434	6,434	6,434	4,969	3,293	3,293	3,293	0	0	0	0	0	0	0	0	0	0	0	0	0
Unspecified	0	0	0	0	0	0	0	0	0	1,100	1,100	1,350	1,350	1,350	1,350	1,350	1,350	1,350	1,850	2,700	3,850
Interconnection	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	750
Annual Peak	26,376	26,657	26,941	27,228	27,585	27,946	28,312	28,683	29,059	29,625	30,201	30,789	31,389	32,000	32,815	33,651	34,508	35,388	36,289	37,214	38,162
Required Resources	30,860	31,189	31,521	31,856	32,274	32,697	33,125	33,559	34,290	34,957	35,638	36,332	37,039	38,080	39,050	40,045	41,065	42,111	43,184	44,284	45,413

Source: OPA

Q. What is the estimated energy production under Case 2A?

A. Energy production and Conservation under Case 2A is summarized in Table 4 and Table 5. By 2027, nuclear resources produce 98 TWh, renewables and Conservation resources generate/conserve 94 TWh, and gas-fired resources produce 28 TWh.

Table 4: Case 2A Energy Production (TWh)

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Conservation	4	5	9	12	13	15	17	19	20	21	22	23	24	25	26	27	28	28	30	31
Renewables	38	40	41	43	45	46	48	49	51	51	53	54	59	60	62	62	63	63	63	63
Nuclear	83	80	80	82	90	92	90	85	74	74	77	74	78	81	93	101	101	101	102	98
Gas	15	17	18	18	18	19	19	23	27	27	26	28	23	25	20	19	19	21	24	28
Coal	29	29	27	22	16	15	16	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	168	171	176	176	183	188	190	177	172	174	177	179	185	191	202	210	211	213	218	220

Source: OPA

Table 5: Case 2A Energy Production as Percentage of Total

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Conservation	2%	3%	5%	7%	7%	8%	9%	11%	12%	12%	12%	13%	13%	13%	13%	13%	13%	13%	14%	14%
Renewables	22%	23%	24%	24%	25%	25%	25%	28%	30%	30%	30%	30%	32%	31%	31%	30%	30%	29%	29%	29%
Nuclear	49%	47%	45%	47%	49%	49%	47%	48%	43%	43%	43%	41%	42%	43%	46%	48%	48%	47%	47%	45%
Gas	9%	10%	10%	10%	10%	10%	10%	13%	15%	16%	15%	16%	13%	13%	10%	9%	9%	10%	11%	13%
Coal	17%	17%	16%	12%	9%	8%	8%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Total	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

Source: OPA

Q. How do the resources in Case 2A compare to those in Case 1A?

A. Table 6 shows that Case 2A has more gas-fired resources (including "unspecified") than Case 1A in order to meet higher demands. Additional gas-fired capacity (1,200 MW) begins in 2016 and reaches just over 5,000 MW by 2027.

Table 6: Comparison of Case 2A to Case 1A (Installed MW)

Installed MW	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Conservation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Renewables	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gas	0	0	0	0	0	0	0	0	0	107	313	768	768	1,293	1,293	1,818	1,818	1,818	1,818	1,818	1,818
Unspecified	0	0	0	0	0	0	0	0	0	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1,600	2,450	3,200
Total	0	0	0	0	0	0	0	0	0	1,207	1,413	1,868	1,868	2,393	2,393	2,918	2,918	2,918	3,418	4,268	5,018

Source: OPA

Q. How does energy production under Case 2A compare to production under Case 1A?

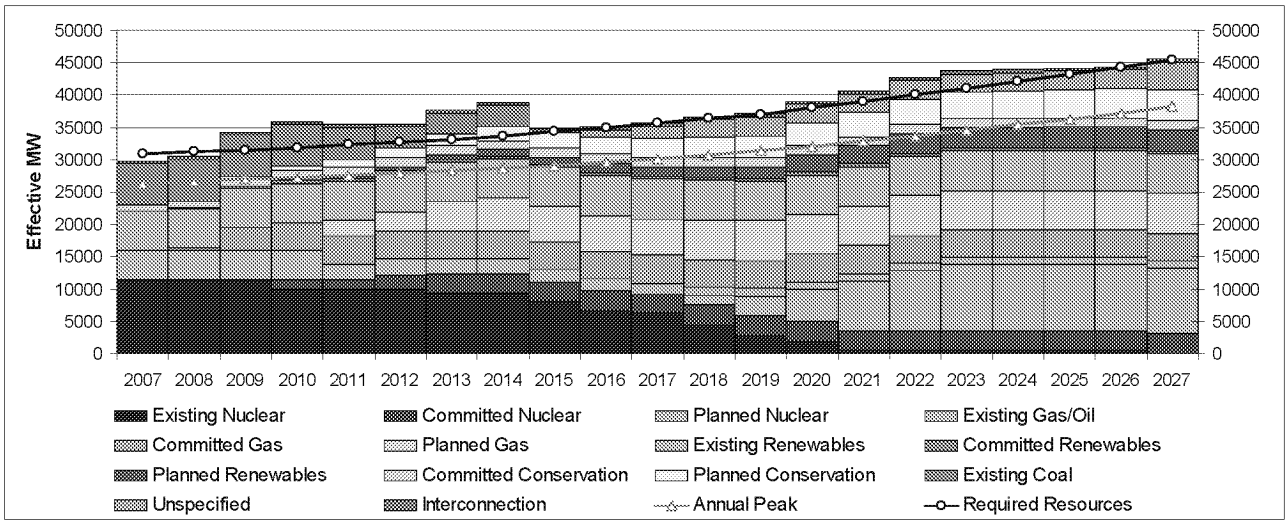
A. Table 7 illustrates that Case 2A sees more production from natural gas-fired resources than Case 1A. By 2027, Case 2A sees 10 TWh more gas-fired production. In addition, Case 2A sees a larger amount of imports.

Table 7: Comparison of Case 2A to Case 1A (TWh)

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Conservation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Renewables	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gas	0	0	0	0	1	1	1	1	3	4	4	5	4	5	4	5	5	6	7	10
Coal	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Imports	0	0	0	1	1	0	1	2	3	3	3	4	5	5	4	4	5	6	7	8

Source: OPA

Figure 3: Case 2B Cumulative Resources (Effective MW)



Source: OPA

Table 8: Case 2B Cumulative Resources (Effective MW)

Effective MW	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Existing Nuclear	11,419	11,419	11,419	9,879	9,879	9,879	9,363	9,363	8,050	6,686	6,170	4,487	2,792	1,911	515	515	515	515	515	515	0
Committed Nuclear	0	0	0	1,500	1,500	2,270	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040
Planned Nuclear	0	0	0	0	0	0	0	0	0	0	0	1,497	3,045	4,926	7,609	9,304	10,185	10,185	10,185	10,185	10,185
Existing Gas/Oil	4,578	4,578	4,578	4,578	2,473	2,473	2,308	2,308	2,004	1,897	1,691	1,236	1,236	1,236	1,236	1,105	1,105	1,105	1,105	1,105	1,105
Committed Gas	0	281	3,431	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267
Planned Gas	0	0	0	0	2,455	2,905	4,507	5,057	5,361	5,467	5,673	6,129	6,129	6,129	6,129	6,129	6,129	6,129	6,129	6,129	6,129
Existing Renewables	6,129	6,129	6,129	6,129	6,129	6,129	6,129	6,129	6,129	6,129	6,129	6,129	6,129	6,129	6,129	6,129	6,129	6,129	6,129	6,129	6,129
Committed Renewables	4	115	317	408	408	408	408	408	408	408	408	408	408	408	408	408	408	408	408	408	408
Planned Renewables	11	25	58	58	303	584	742	982	1,143	1,491	1,529	1,638	1,871	2,662	2,770	3,135	3,135	3,157	3,255	3,255	3,255
Committed Conservation	755	1,006	1,375	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407
Planned Conservation	0	0	0	755	1,084	1,413	1,741	2,070	2,398	2,614	2,878	3,146	3,358	3,560	3,722	3,884	4,043	4,206	4,354	4,583	4,811
Existing Coal	6,434	6,434	6,434	6,434	4,969	3,293	3,293	3,293	0	0	0	0	0	0	0	0	0	0	0	0	0
Unspecified	0	0	0	0	0	0	0	0	0	1,100	1,980	2,730	2,855	2,855	2,855	2,855	2,855	2,855	2,855	2,855	4,255
Interconnection	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500
Annual Peak	26,376	26,657	26,941	27,228	27,585	27,946	28,312	28,683	29,059	29,625	30,201	30,789	31,389	32,000	32,815	33,651	34,508	35,388	36,289	37,214	38,162
Required Resources	30,860	31,189	31,521	31,856	32,274	32,697	33,125	33,559	34,290	34,957	35,638	36,332	37,039	38,080	39,050	40,045	41,065	42,111	43,184	44,284	45,413

Source:

Table 9: Case 2B Cumulative Resources (Installed MW)

Installed MW	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Existing Nuclear	11,419	11,419	11,419	9,879	9,879	9,879	9,363	9,363	8,050	6,686	6,170	4,487	2,792	1,911	515	515	515	515	515	515	0
Committed Nuclear	0	0	0	1,500	1,500	2,270	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040
Planned Nuclear	0	0	0	0	0	0	0	0	0	0	0	1,497	3,045	4,926	7,609	9,304	10,185	10,185	10,185	10,185	10,185
Existing Gas/Oil	5,103	5,103	5,103	5,103	2,998	2,998	2,833	2,833	2,529	2,422	2,216	1,761	1,761	1,761	1,761	1,630	1,630	1,630	1,630	1,630	1,630
Committed Gas	0	281	3,431	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267
Planned Gas	0	0	0	0	2,455	2,905	4,507	5,057	5,361	5,467	5,673	6,129	6,129	6,129	6,129	6,129	6,129	6,129	6,129	6,129	6,129
Existing Renewables	8,258	8,258	8,258	8,258	8,258	8,258	8,258	8,258	8,258	8,258	8,258	8,258	8,258	8,258	8,258	8,258	8,258	8,258	8,258	8,258	8,258
Committed Renewables	5	331	1,158	1,415	1,415	1,415	1,415	1,415	1,415	1,415	1,415	1,415	1,415	1,415	1,415	1,415	1,415	1,415	1,415	1,415	1,415
Planned Renewables	16	36	81	81	855	1,260	1,729	2,335	2,692	3,278	3,380	3,837	4,129	5,599	5,746	6,247	6,247	6,276	6,411	6,411	6,411
Committed Conservation	755	1,006	1,375	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407
Planned Conservation	0	0	0	755	1,084	1,413	1,741	2,070	2,398	2,614	2,878	3,146	3,358	3,560	3,722	3,884	4,043	4,206	4,354	4,583	4,811
Existing Coal	6,434	6,434	6,434	6,434	4,969	3,293	3,293	3,293	0	0	0	0	0	0	0	0	0	0	0	0	0
Unspecified	0	0	0	0	0	0	0	0	0	1,100	1,980	2,730	2,855	2,855	2,855	2,855	2,855	2,855	2,855	2,855	4,255
Interconnection	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500
Annual Peak	26,376	26,657	26,941	27,228	27,585	27,946	28,312	28,683	29,059	29,625	30,201	30,789	31,389	32,000	32,815	33,651	34,508	35,388	36,289	37,214	38,162
Required Resources	30,860	31,189	31,521	31,856	32,274	32,697	33,125	33,559	34,290	34,957	35,638	36,332	37,039	38,080	39,050	40,045	41,065	42,111	43,184	44,284	45,413

Source:

Q. What is the estimated energy production under Case 2B?

A. Energy production and Conservation under Case 2B is summarized in Table 4 and Table 11. By 2027, nuclear resources produce 100 TWh, renewables and Conservation resources generate/conserve 94 TWh, and gas-fired resources produce 27 TWh.

Table 10: Case 2B Energy Production (TWh)

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Conservation	4	5	9	12	13	15	17	19	20	21	22	23	24	25	26	27	28	28	30	31
Renewables	38	40	41	43	45	46	48	49	51	51	53	54	59	60	62	62	62	63	63	63
Nuclear	83	80	80	82	90	92	90	82	71	68	66	64	71	81	95	102	103	102	104	100
Gas	15	17	18	18	18	19	19	23	28	29	29	32	27	27	20	19	19	20	22	27
Coal	29	29	27	22	16	15	16	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	168	171	176	176	183	188	190	173	170	170	170	172	181	193	202	210	212	214	219	221

Source: OPA

Table 11: Case 2B Energy Production as Percentage of Total

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Conservation	2%	3%	5%	7%	7%	8%	9%	11%	12%	12%	13%	13%	13%	13%	13%	13%	13%	13%	14%	14%
Renewables	22%	23%	24%	24%	25%	25%	25%	29%	30%	30%	31%	31%	33%	31%	31%	30%	29%	29%	29%	29%
Nuclear	49%	47%	45%	47%	49%	49%	47%	47%	42%	40%	39%	37%	39%	42%	47%	49%	49%	48%	48%	46%
Gas	9%	10%	10%	10%	10%	10%	10%	13%	16%	17%	17%	18%	15%	14%	10%	9%	9%	9%	10%	12%
Coal	17%	17%	16%	12%	9%	8%	8%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Total	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

Source: OPA

Q. How does energy production under Case 2B compare to production under Case 1B?

A. Table 12 illustrates that Case 2B sees more production from natural gas-fired resources than Case 1B. By 2027, Case 2B sees 9 TWh more gas-fired production. In addition, Case 2B sees a larger amount of imports.

Table 12: Comparison of Case 2B to Case 1B (TWh)

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Conservation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Renewables	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gas	0	0	0	0	1	1	1	1	2	3	4	5	4	4	4	4	4	5	6	9
Coal	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Imports	0	0	0	1	1	0	1	2	3	3	3	4	5	4	4	4	5	6	6	8

Source: OPA

Q. How does energy production under Case 2B compare to production under Case 2A?

A. As illustrated in Table 13, Case 2B sees less production from nuclear resources than Case 2A. Case 2B sees more natural gas-fired production. Imports are greater between 2015 and 2020, though decrease as of 2021.

Table 13: Comparison of Case 2B to Case 2A (TWh)

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Conservation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Renewables	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Nuclear	0	0	0	0	0	0	0	-4	-4	-7	-10	-10	-7	0	1	1	2	1	2	2
Gas	0	0	0	0	0	0	0	0	1	2	3	4	3	2	-1	-1	-1	-1	-1	-2
Coal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Imports	0	0	0	0	0	0	0	2	1	2	5	4	1	-2	0	0	-1	0	-1	-1

Source: OPA

Q. How does energy production under Case 2B compare to production under Case 1A?

A. As shown in Table 14, the combined impact of higher than forecast demands and no Pickering B refurbishment results in increased production from gas-fired generation and increased imports during the period 2015 to 2021. During the period after 2021, Case 2B has higher gas-fired production, nuclear production and imports than Case 1A.

Table 14: Comparison of Case 2B to Case 1A (TWh)

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Conservation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Renewables	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Nuclear	0	0	0	0	0	0	0	-4	-4	-7	-10	-10	-7	0	1	1	2	1	2	2
Gas	0	0	0	0	1	1	1	1	4	6	8	9	8	7	4	4	4	5	6	8
Coal	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Imports	0	0	0	1	1	0	1	3	4	5	8	8	6	3	4	4	5	6	6	7

Source: OPA

Q. Do the energy production simulations conducted for Cases 2A and 2B result in any unsupplied demand?

A. No. Cases 2A and 2B do not result in any unsupplied demand.

Q. What do Cases 2A and 2B demonstrate?

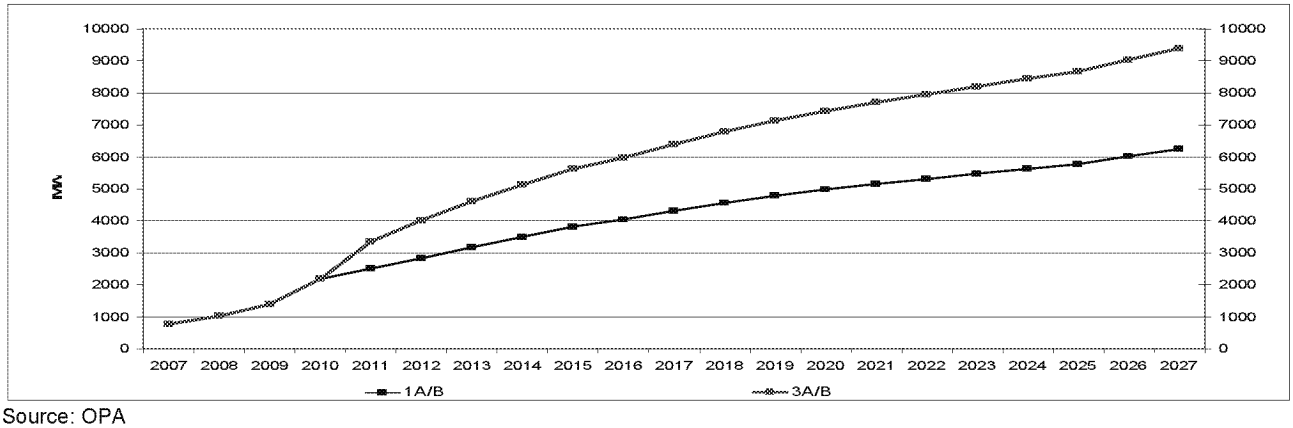
A. Cases 2A and 2B demonstrate that it is feasible to adapt the Plan to reliably meet higher requirements. In the near- to mid term, additional requirements can be met by resources committed and planned under reference conditions as well as by somewhat greater use of imports. In the longer term, increased requirements can be met through additional resources as well as increased imports.

4.0 CASE 3

Q. Was a higher Conservation case considered?

A. Yes. Cases 3A and 3B see about 9,400 MW and 46 TWh of Conservation by the end of the Plan period, compared to the 6,200 MW and 31 TWh of Conservation represented in the other cases. Conservation totals in each of the scenarios are compared in Figure 4, Figure 5, Table 15, and Table 16. It will be seen in Figure 4 and Figure 7 that the forecast annual peak demand net of Conservation under the higher Conservation scenarios is about 24,000 MW by 2027 compared to just over 27,000 MW under the reference Conservation scenarios. Annual energy demand net of Conservation is about 150 TWh by 2027 under the higher Conservation scenario compared to about 165 TWh by 2027 under the reference scenario.

Figure 4: Comparison of Conservation under Reference and Higher Conservation Scenarios (MW)



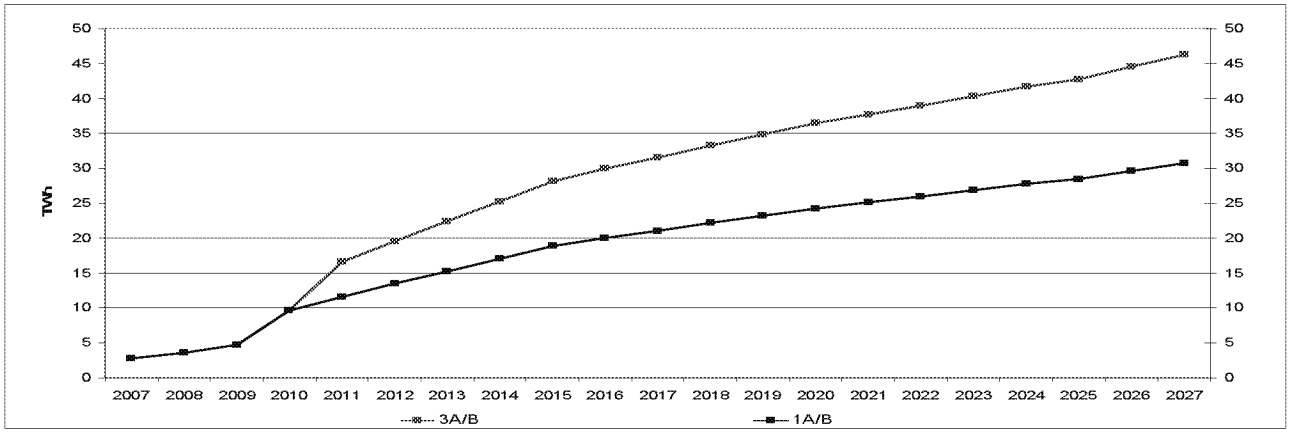
Source: OPA

Table 15: Comparison of Conservation under Reference and Higher Conservation Scenarios (MW)

MW	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Higher Conservation	755	1,006	1,375	2,162	3,331	4,006	4,589	5,105	5,618	5,954	6,362	6,777	7,106	7,420	7,673	7,925	8,172	8,426	8,656	9,015	9,373
Reference Conservation	755	1,006	1,375	2,162	2,491	2,820	3,148	3,477	3,805	4,021	4,285	4,553	4,765	4,967	5,129	5,291	5,450	5,613	5,761	5,990	6,218

Source: OPA

Figure 5: Comparison of Conservation under Reference and Higher Conservation Scenarios (TWh)



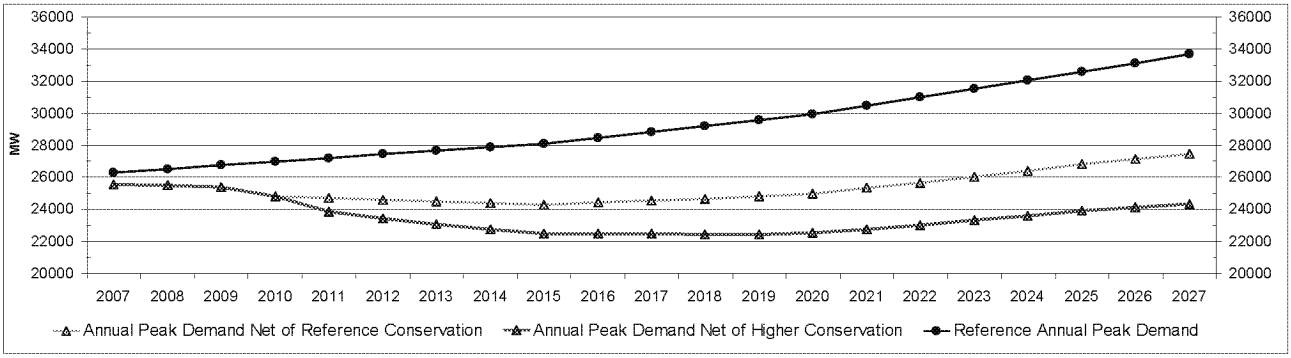
Source: OPA

Table 16: Comparison of Conservation under Reference and Higher Conservation Scenarios (TWh)

TWh	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Higher Conservation	3	4	5	10	17	19	22	25	28	30	32	33	35	36	38	39	40	42	43	44	46
Reference Conservation	3	4	5	10	12	13	15	17	19	20	21	22	23	24	25	26	27	28	28	30	31

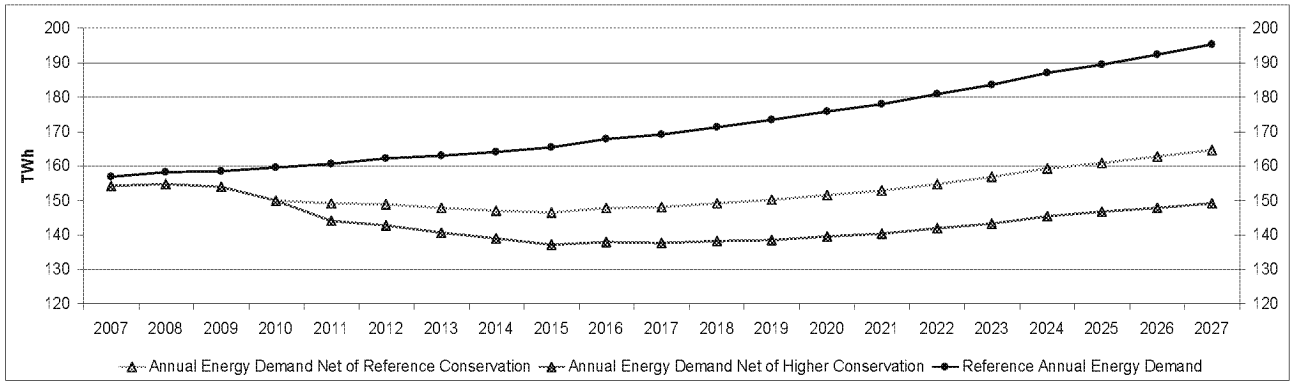
Source:

Figure 6: Annual Peak Demand under Reference and Higher Conservation Scenarios



Source:

Figure 7: Annual Energy Demand under Reference and Higher Conservation Scenarios



Source:

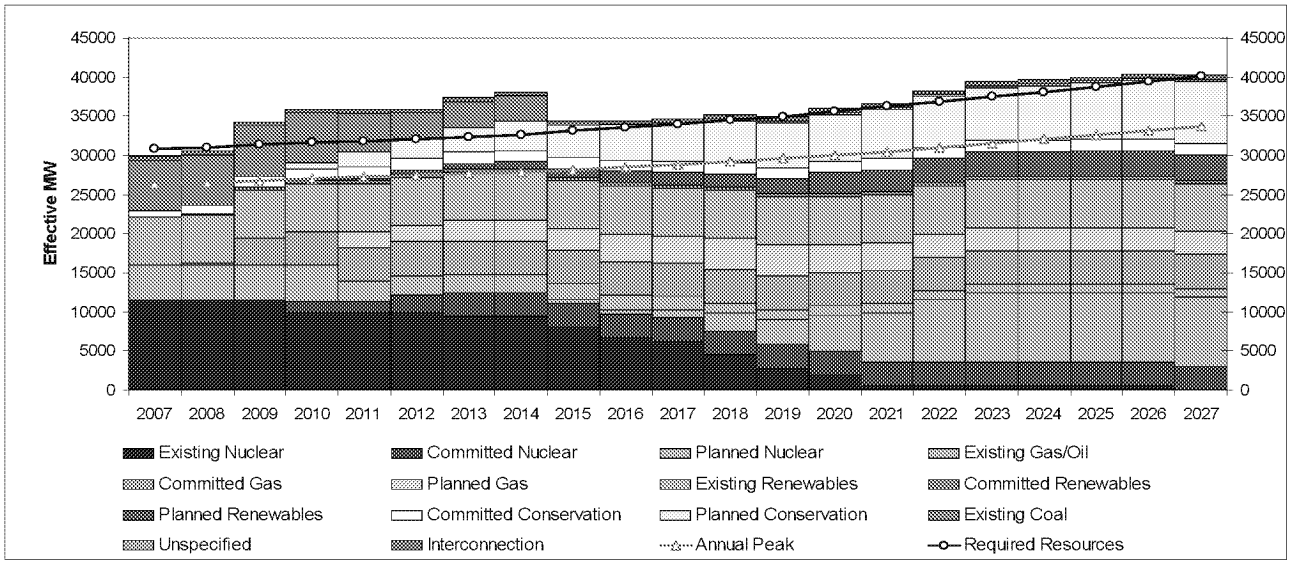
Q. What is the purpose of considering a higher Conservation case?

A. The purpose of exploring a higher Conservation case is to test how the Plan could adapt to meet a lower demand requirement.

Q. What are possible adaptations of the Plan under a higher Conservation case?

Possible adaptations are referred to as Cases 3A and 3B and are illustrated in Figure 8, Figure 9,Table 17, Table 18, Table 23 and Table 24. In brief, the additional Conservation could either reduce and/or defer the requirement for about 3,200 MW and 15 TWh of planned resources over the long term. In the near- to medium term, this can result in greater potential for reduction in the amount of existing natural gas-fired generation resources (e.g., as they reach end-of-service or end of contractual term). In the same timeframe, the additional Conservation could also reduce and/or defer the requirement for new gas-fired generation and could advance the closure of some coal-fired units. In the longer term, the additional 15 TWh of Conservation could reduce and/or defer the requirement for nuclear resources, whether in the form of refurbishments or new-build. The reduction in nuclear generation starts in 2018, with sufficient lead time to be addressed in the next IPSP.

Figure 8: Case 3A Cumulative Resources (Effective MW)



Source: OPA

Table 17: Case 3A Cumulative Resources (Effective MW)

Effective MW	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Existing Nuclear	11,419	11,419	11,419	9,879	9,879	9,879	9,363	9,363	8,050	6,686	6,170	4,487	2,792	1,911	515	515	515	515	515	515	0
Committed Nuclear	0	0	0	1,500	1,500	2,270	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040
Planned Nuclear	0	0	0	0	0	0	0	0	516	516	1,032	2,345	3,193	4,590	6,273	7,968	8,849	8,849	8,849	8,849	8,849
Existing Gas/Oil	4,578	4,578	4,578	4,578	2,473	2,473	2,308	2,308	2,004	1,897	1,691	1,236	1,236	1,236	1,236	1,105	1,105	1,105	1,105	1,105	1,105
Committed Gas	0	281	3,431	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267
Planned Gas	0	0	0	0	2,105	2,105	2,691	2,691	2,691	3,491	3,491	4,041	4,041	3,516	3,516	2,991	2,991	2,991	2,991	2,991	2,991
Existing Renewables	6,129	6,129	6,129	6,129	6,129	6,129	6,129	6,129	6,129	6,129	6,129	6,129	6,129	6,129	6,129	6,129	6,129	6,129	6,129	6,129	6,129
Committed Renewables	4	115	317	408	408	408	408	408	408	408	408	408	408	408	408	408	408	408	408	408	408
Planned Renewables	11	25	58	58	303	584	742	982	1,143	1,491	1,529	1,638	1,871	2,662	2,770	3,135	3,135	3,157	3,255	3,255	3,255
Committed Conservation	755	1,006	1,375	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407
Planned Conservation	0	0	0	755	1,924	2,599	3,182	3,698	4,211	4,547	4,955	5,370	5,699	6,013	6,266	6,518	6,765	7,019	7,249	7,608	7,966
Existing Coal	6,434	6,434	6,434	6,434	4,969	3,293	3,293	3,293	0	0	0	0	0	0	0	0	0	0	0	0	0
Unspecified	0	0	0	0	0	0	0	0	0	0	0	250	250	250	250	250	250	250	250	250	250
Interconnection	500	500	500	500	500	500	500	500	500	500	500	500	580	500	500	500	500	500	500	500	500
Annual Peak	26,282	26,515	26,749	26,986	27,205	27,426	27,648	27,873	28,099	28,457	28,820	29,187	29,559	29,936	30,444	30,960	31,485	32,020	32,563	33,115	33,677
Required Resources	30,750	31,022	31,296	31,573	31,830	32,088	32,349	32,611	33,157	33,580	34,008	34,441	34,880	35,624	36,228	36,843	37,468	38,103	38,750	39,407	40,076

Source:

Table 18: Case 3A Cumulative Resources (Installed MW)

Installed MW	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Existing Nuclear	11,419	11,419	11,419	9,879	9,879	9,879	9,363	9,363	8,050	6,686	6,170	4,487	2,792	1,911	515	515	515	515	515	515	0
Committed Nuclear	0	0	0	1,500	1,500	2,270	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040
Planned Nuclear	0	0	0	0	0	0	0	0	516	516	1,032	2,345	3,193	4,590	6,273	7,968	8,849	8,849	8,849	8,849	8,849
Existing Gas/Oil	5,103	5,103	5,103	5,103	2,998	2,998	2,833	2,833	2,529	2,422	2,216	1,761	1,761	1,761	1,761	1,630	1,630	1,630	1,630	1,630	1,630
Committed Gas	0	281	3,431	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267
Planned Gas	0	0	0	0	2,105	2,105	2,691	2,691	2,691	3,491	3,491	4,041	4,041	3,516	3,516	2,991	2,991	2,991	2,991	2,991	2,991
Existing Renewables	8,258	8,258	8,258	8,258	8,258	8,258	8,258	8,258	8,258	8,258	8,258	8,258	8,258	8,258	8,258	8,258	8,258	8,258	8,258	8,258	8,258
Committed Renewables	5	331	1,158	1,415	1,415	1,415	1,415	1,415	1,415	1,415	1,415	1,415	1,415	1,415	1,415	1,415	1,415	1,415	1,415	1,415	1,415
Planned Renewables	16	36	81	81	855	1,260	1,729	2,335	2,692	3,278	3,380	3,837	4,129	5,599	5,746	6,247	6,247	6,276	6,411	6,411	6,411
Committed Conservation	755	1,006	1,375	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407
Planned Conservation	0	0	0	755	1,924	2,599	3,182	3,698	4,211	4,547	4,955	5,370	5,699	6,013	6,266	6,518	6,765	7,019	7,249	7,608	7,966
Existing Coal	6,434	6,434	6,434	6,434	4,969	3,293	3,293	3,293	0	0	0	0	0	0	0	0	0	0	0	0	0
Unspecified	0	0	0	0	0	0	0	0	0	0	0	250	250	250	250	250	250	250	250	250	250
Interconnection	500	500	500	500	500	500	500	500	500	500	500	500	580	500	500	500	500	500	500	500	500
Annual Peak	26,282	26,515	26,749	26,986	27,205	27,426	27,648	27,873	28,099	28,457	28,820	29,187	29,559	29,936	30,444	30,960	31,485	32,020	32,563	33,115	33,677
Required Resources	30,750	31,022	31,296	31,573	31,830	32,088	32,349	32,611	33,157	33,580	34,008	34,441	34,880	35,624	36,228	36,843	37,468	38,103	38,750	39,407	40,076

Source:

Q. What is the estimated energy production under Case 3A?

Energy production and Conservation under Case 3A is summarized in Table 19 and Table 20. By 2027, nuclear resources produce 87 TWh (or 41% of total energy production/Conservation), renewables and Conservation resources generate/conserve 109 TWh (or 52% of total energy production/Conservation), and gas-fired resources produce 16 TWh.

Table 19: Case 3A Energy Production (TWh)

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Conservation	4	5	10	17	19	22	25	28	30	32	33	35	36	38	39	40	42	43	45	46
Renewables	38	40	41	43	45	46	48	49	51	52	53	54	60	60	62	62	63	63	63	63
Nuclear	83	80	80	82	90	92	90	85	74	74	72	64	68	71	83	91	91	91	91	87
Gas	15	17	18	17	17	17	17	20	21	20	18	20	18	19	15	13	13	13	15	16
Coal	29	28	27	21	14	13	14	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	168	170	176	180	185	191	193	183	176	178	176	173	182	188	199	207	208	210	213	213

Source:

Table 20: Case 3A Energy Production as Percentage of Total

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Conservation	2%	3%	5%	9%	11%	12%	13%	15%	17%	18%	19%	20%	20%	20%	20%	19%	20%	20%	21%	22%
Renewables	22%	24%	24%	24%	24%	24%	25%	27%	29%	29%	30%	31%	33%	32%	31%	30%	30%	30%	30%	30%
Nuclear	49%	47%	45%	46%	48%	48%	46%	47%	42%	42%	41%	37%	37%	38%	42%	44%	44%	43%	43%	41%
Gas	9%	10%	10%	9%	9%	9%	9%	11%	12%	11%	10%	12%	10%	10%	7%	6%	6%	6%	7%	8%
Coal	17%	17%	15%	12%	8%	7%	7%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Total	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

Source:

Q. How do the resources in Case 3A compare to those in Case 1A?

A. As shown in Table 21, the impact of higher Conservation is a reduction in the amount of gas-fired resources beginning in 2011 and a reduction in the amount of nuclear generation beginning in 2018. As of 2019, and for the remainder of the Plan period, gas-fired generation is reduced by 1,319 MW and nuclear generation is reduced by 1,400 MW.

Table 21: Comparison of Case 3A to Case 1A (Installed MW)

Installed MW	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Conservation	0	0	0	0	840	1,186	1,441	1,628	1,813	1,933	2,077	2,224	2,341	2,453	2,544	2,634	2,722	2,813	2,895	3,025	3,155
Renewables	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Nuclear	0	0	0	0	0	0	0	0	0	0	0	-700	-1,400	-1,400	-1,400	-1,400	-1,400	-1,400	-1,400	-1,400	-1,400
Gas	0	0	0	0	-350	-800	-1,815	-2,365	-2,669	-1,869	-1,869	-1,319	-1,319	-1,319	-1,319	-1,319	-1,319	-1,319	-1,319	-1,319	-1,319
Coal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Unspecified	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-400
Total	0	0	0	0	490	386	-374	-737	-857	63	208	205	-378	-267	-176	-86	3	93	176	306	35

Source: OPA

Q. How does energy production under Case 3A compare to production under Case 1A?

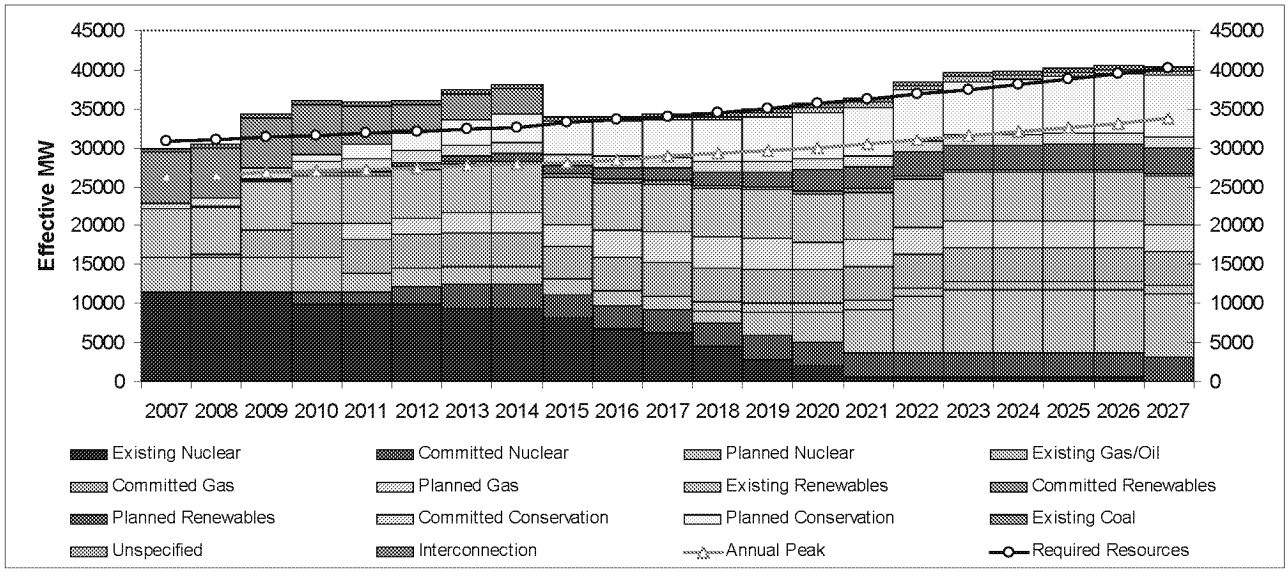
A. Table 22 illustrates that Case 3A sees 15 TWh more Conservation than Case 1A. By 2027, Case 3A also sees about 11 TWh less nuclear production, 2 TWh less gas-fired production, and fewer imports.

Table 22: Comparison of Case 3A to Case 1A (TWh)

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Conservation	0	0	1	5	6	7	8	9	10	10	11	12	12	13	13	13	14	14	15	15
Renewables	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Nuclear	0	0	0	0	0	0	0	0	0	0	-5	-10	-10	-10	-10	-10	-11	-11	-11	-11
Gas	0	0	0	-1	-1	-1	-1	-2	-3	-3	-3	-3	-1	-1	-1	-2	-1	-2	-2	-2
Coal	0	0	0	-1	-1	-1	-2	0	0	0	0	0	0	0	0	0	0	0	0	0
Imports	0	0	0	-2	-1	0	-1	-2	-3	-4	-1	1	-1	-1	0	0	0	0	-1	-1

Source:

Figure 9: Case 3B Cumulative Resources (Effective MW)



Source: OPA

Table 23: Case 3B Cumulative Resources (Effective MW)

Effective MW	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Existing Nuclear	11,419	11,419	11,419	9,879	9,879	9,879	9,363	9,363	8,050	6,686	6,170	4,487	2,792	1,911	515	515	515	515	515	515	0
Committed Nuclear	0	0	0	1,500	1,500	2,270	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040
Planned Nuclear	0	0	0	0	0	0	0	0	0	0	0	1,497	3,045	3,926	5,609	7,304	8,185	8,185	8,185	8,185	8,185
Existing Gas/Oil	4,578	4,578	4,578	4,578	2,473	2,473	2,308	2,308	2,004	1,897	1,691	1,236	1,236	1,236	1,236	1,105	1,105	1,105	1,105	1,105	1,105
Committed Gas	0	281	3,431	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267
Planned Gas	0	0	0	0	2,105	2,105	2,691	2,691	2,691	3,491	4,041	4,041	4,041	3,516	3,516	3,516	3,516	3,516	3,516	3,516	3,516
Existing Renewables	6,129	6,129	6,129	6,129	6,129	6,129	6,129	6,129	6,129	6,129	6,129	6,129	6,129	6,129	6,129	6,129	6,129	6,129	6,129	6,129	6,129
Committed Renewables	4	115	317	408	408	408	408	408	408	408	408	408	408	408	408	408	408	408	408	408	408
Planned Renewables	11	25	58	58	303	584	742	982	1,143	1,491	1,529	1,638	1,871	2,662	2,770	3,135	3,135	3,157	3,255	3,255	3,255
Committed Conservation	755	1,006	1,375	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407
Planned Conservation	0	0	0	755	1,924	2,599	3,182	3,698	4,211	4,547	4,955	5,370	5,699	6,013	6,266	6,518	6,765	7,019	7,249	7,608	7,966
Existing Coal	6,434	6,434	6,434	6,434	4,969	3,293	3,293	3,293	0	0	0	0	0	0	0	0	0	0	0	0	0
Unspecified	0	0	0	0	0	0	0	0	0	0	200	450	450	600	600	600	600	600	600	600	600
Interconnection	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500
Annual Peak	26,282	26,515	26,749	26,986	27,205	27,426	27,648	27,873	28,099	28,457	28,820	29,187	29,559	29,936	30,444	30,960	31,485	32,020	32,563	33,115	33,677
Required Resources	30,750	31,022	31,296	31,573	31,830	32,088	32,349	32,611	33,157	33,580	34,008	34,441	34,880	35,624	36,228	36,843	37,468	38,103	38,750	39,407	40,076

Source:

Table 24: Case 3B Cumulative Resources (Installed MW)

Installed MW	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Existing Nuclear	11,419	11,419	11,419	9,879	9,879	9,879	9,363	9,363	8,050	6,686	6,170	4,487	2,792	1,911	515	515	515	515	515	515	0
Committed Nuclear	0	0	0	1,500	1,500	2,270	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040
Planned Nuclear	0	0	0	0	0	0	0	0	0	0	0	1,497	3,045	3,926	5,609	7,304	8,185	8,185	8,185	8,185	8,185
Existing Gas/Oil	5,103	5,103	5,103	5,103	2,998	2,998	2,833	2,833	2,529	2,422	2,216	1,761	1,761	1,761	1,761	1,630	1,630	1,630	1,630	1,630	1,630
Committed Gas	0	281	3,431	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267
Planned Gas	0	0	0	0	2,105	2,105	2,691	2,691	2,691	3,491	4,041	4,041	4,041	3,516	3,516	3,516	3,516	3,516	3,516	3,516	3,516
Existing Renewables	8,258	8,258	8,258	8,258	8,258	8,258	8,258	8,258	8,258	8,258	8,258	8,258	8,258	8,258	8,258	8,258	8,258	8,258	8,258	8,258	8,258
Committed Renewables	5	331	1,158	1,415	1,415	1,415	1,415	1,415	1,415	1,415	1,415	1,415	1,415	1,415	1,415	1,415	1,415	1,415	1,415	1,415	1,415
Planned Renewables	16	36	81	81	855	1,260	1,729	2,335	2,692	3,278	3,380	3,837	4,129	5,599	5,746	6,247	6,247	6,276	6,411	6,411	6,411
Committed Conservation	755	1,006	1,375	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407
Planned Conservation	0	0	0	755	1,924	2,599	3,182	3,698	4,211	4,547	4,955	5,370	5,699	6,013	6,266	6,518	6,765	7,019	7,249	7,608	7,966
Existing Coal	6,434	6,434	6,434	6,434	4,969	3,293	3,293	3,293	0	0	0	0	0	0	0	0	0	0	0	0	0
Unspecified	0	0	0	0	0	0	0	0	0	0	200	450	450	600	600	600	600	600	600	600	600
Interconnection	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500
Annual Peak	26,282	26,515	26,749	26,986	27,205	27,426	27,648	27,873	28,099	28,457	28,820	29,187	29,559	29,936	30,444	30,960	31,485	32,020	32,563	33,115	33,677
Required Resources	30,750	31,022	31,296	31,573	31,830	32,088	32,349	32,611	33,157	33,580	34,008	34,441	34,880	35,624	36,228	36,843	37,468	38,103	38,750	39,407	40,076

Source:

Q. What is the estimated energy production under Case 3B?

A. Energy production and Conservation under Case 3B is summarized in Table 25 and Table 26. By 2027, nuclear resources produce 85 TWh, renewables and Conservation resources generate/conserve 109 TWh, and gas-fired resources produce 17 TWh.

Table 25: Case 3B Energy Production (TWh)

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Conservation	4	5	10	17	19	22	25	28	30	32	33	35	36	38	39	40	42	43	45	46
Renewables	38	40	41	43	45	46	48	49	52	52	53	54	60	60	62	62	63	63	63	63
Nuclear	83	80	80	82	90	92	90	82	71	68	66	64	64	67	80	87	88	87	89	85
Gas	15	17	18	17	17	17	17	19	22	22	21	22	21	22	15	14	13	14	15	17
Coal	29	28	27	21	14	13	14	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	168	170	176	180	185	191	193	179	175	173	173	175	181	187	196	204	206	207	211	211

Source:

Table 26: Case 3B Energy Production as Percentage of Total

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Conservation	2%	3%	5%	9%	11%	12%	13%	16%	17%	18%	19%	20%	20%	20%	20%	20%	20%	21%	21%	22%
Renewables	22%	24%	24%	24%	24%	24%	25%	28%	30%	30%	31%	31%	33%	32%	32%	31%	30%	30%	30%	30%
Nuclear	49%	47%	45%	46%	48%	48%	46%	46%	41%	39%	38%	36%	35%	36%	41%	43%	43%	42%	42%	40%
Gas	9%	10%	10%	9%	9%	9%	9%	11%	13%	13%	12%	13%	11%	12%	8%	7%	7%	7%	7%	8%
Coal	17%	17%	15%	12%	8%	7%	7%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Total	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

Source:

Q. How does energy production under Case 3B compare to production under Case 1B?

A. Table 27 illustrates that Case 3B sees up to 15 TWh more Conservation than Case 1B. By 2027, Case 3B also sees about 16 TWh less nuclear production and 1 TWh less gas-fired production. During the mid term, Case 3B sees fewer imports.

Table 27: Comparison of Case 3B to Case 1B (TWh)

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Conservation	0	0	1	5	6	7	8	9	10	10	11	12	12	13	13	13	14	14	15	15
Renewables	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	-7	-14	-14	-14	-15	-15	-16	-16
Gas	0	0	0	-1	-1	-1	-1	-2	-3	-4	-4	-5	-2	-1	-1	-1	-1	-1	-1	-1
Coal	0	0	0	-1	-1	-1	-2	0	0	0	0	0	0	0	0	0	0	0	0	0
Imports	0	0	0	-2	-1	0	-1	-3	-4	-4	-4	-4	-2	1	0	0	0	0	0	0

Source:

Q. How does energy production under Case 3B compare to production under Case 3A?

A. As illustrated in Table 28, Case 3B sees less production from nuclear resources than Case 3A. Case 3B sees more natural gas-fired production and generally higher imports.

Table 28: Comparison of Case 3B to Case 3A (TWh)

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Conservation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Renewables	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Nuclear	0	0	0	0	0	0	0	-4	-4	-7	-6	0	-4	-4	-3	-4	-3	-3	-2	-3
Gas	0	0	0	0	0	0	0	-1	2	2	3	2	3	3	1	1	0	1	1	1
Coal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Imports	0	0	0	0	0	0	0	1	1	1	1	-1	0	0	1	0	0	0	0	0

Source:

Q. Do the energy production simulations conducted for Cases 3A and 3B result in any unsupplied demand?

A. No. Cases 3A and 3B do not result in any unsupplied demand.

Q. What do Cases 3A and 3B demonstrate?

A. Cases 3A and 3B demonstrate that it is feasible to adapt the Plan to reliably meet lower demand requirements. In the near- to mid term, adaptations can include advancing the reduction in coal–fired generation, and deferring or avoiding the requirement for planned natural gas-fired projects. In the mid- to longer term, adaptations can include fewer imports, and deferring or avoiding the requirement for planned nuclear resources.

5.0 CASE 4

Q. Was a case considered where major transmission required to incorporate northern renewables was not implemented?

A. Yes. Cases 4A and 4B explore how resource requirements and directed renewable targets could be met in the event that transmission required to incorporate northern renewables is not implemented. The transmission in question is sometimes referred to as the "North-South Tie" and is discussed in detail in Exhibit E-3-1. The consequence of not implementing the North-South Tie would be the inability to incorporate at least 2,000 MW of planned northern hydroelectric potential (around the Moose River Basin and Albany River) and at least 500 MW of planned wind potential (around the Lake Superior region)2. The 2,500 MW of installed northern renewable capacity would amount to about 1,600 MW in effective terms.

Q. What is the purpose of considering a "No North-South Tie" case?

A. The purpose of considering a no North-South Tie scenario is to explore how the Plan could be adapted to meet requirements and directed renewables targets in the event that transmission to incorporate northern renewables is not developed or in the event of lower availability or feasibility of northern renewables.

[2] Additional amounts of northern renewable resources such as biomass could also be impacted under this scenario.

Q. What are possible adaptations of the Plan under a No North-South Tie case?

A. The essence of the response under this case is to replace the foregone renewables with an equivalent amount of installed renewable capacity as well as make up for any potential differences in load meeting capability.

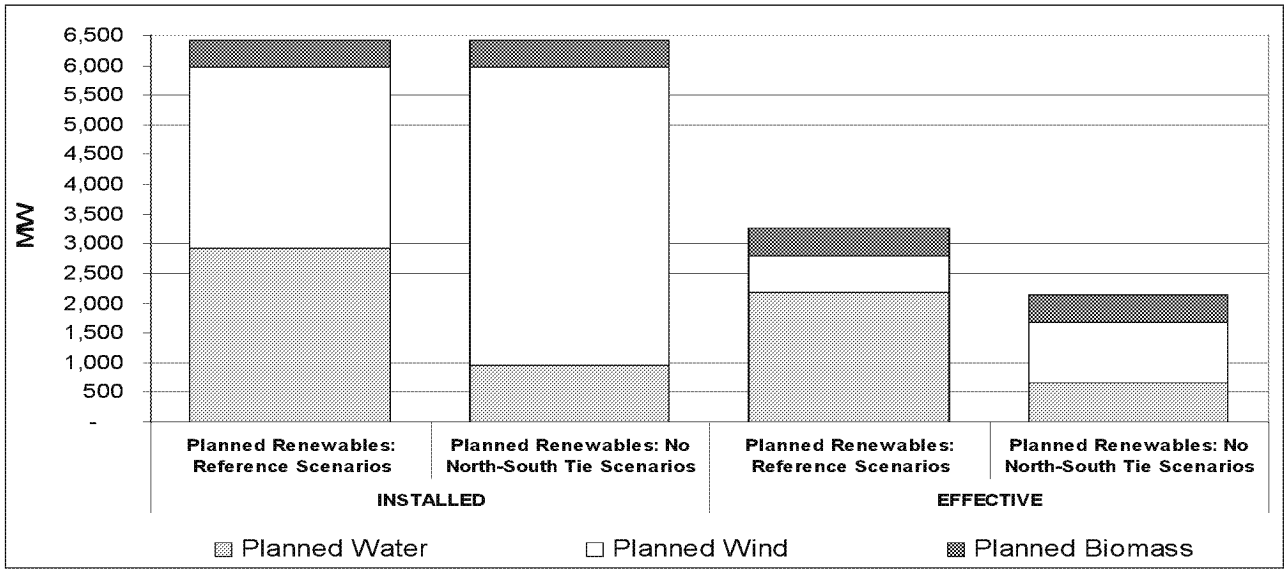
Cases 4A and 4B illustrate the 2,500 MW of northern water and wind resources as being replaced by 2,500 MW of wind resources developed in other areas of Ontario. Cases 4A and 4B would contain 2,000 MW fewer hydroelectric resources than cases 1A/B through 3A/B (for a total of about 8,800 MW by 2027) and would contain 2,000 MW more wind resources (for a total of about 6,700 MW by 2027). This is illustrated in Figure 10, Figure 11, and Figure 12 where planned renewables and total renewables under the reference and no North-South Tie scenarios are compared.

It is recognized that developing an additional 2,500 MW of wind power in areas outside of the northern parts of the province could represent a challenge in terms of feasibility and cost-effectiveness. As illustrated, there would need to be a high success rate (in the order of 100%) of implementing remaining wind potential identified in Exhibit E-2-2 (i.e., remaining potential beyond the potential already planned for under Cases 1A/B through 3A/B). There might also be a need to resort to less cost effective wind resources than those identified under Case 1A/B through 3A/B. In addition, higher penetrations of wind power into Ontario's power system might require additional investment in load following and ancillary service capability relative to that required under Cases 1A/B through 3A/B.

Since the 2,500 MW of replacement wind illustrated in Cases 4A and 4B has an estimated effective contribution of about 500 MW, another 1,100 MW or so of additional load meeting capability would be required. For simulation purposes, this additional capability is assumed to be provided by unspecified resources with capabilities and costs similar to those of a simple cycle natural gas-fired generator.

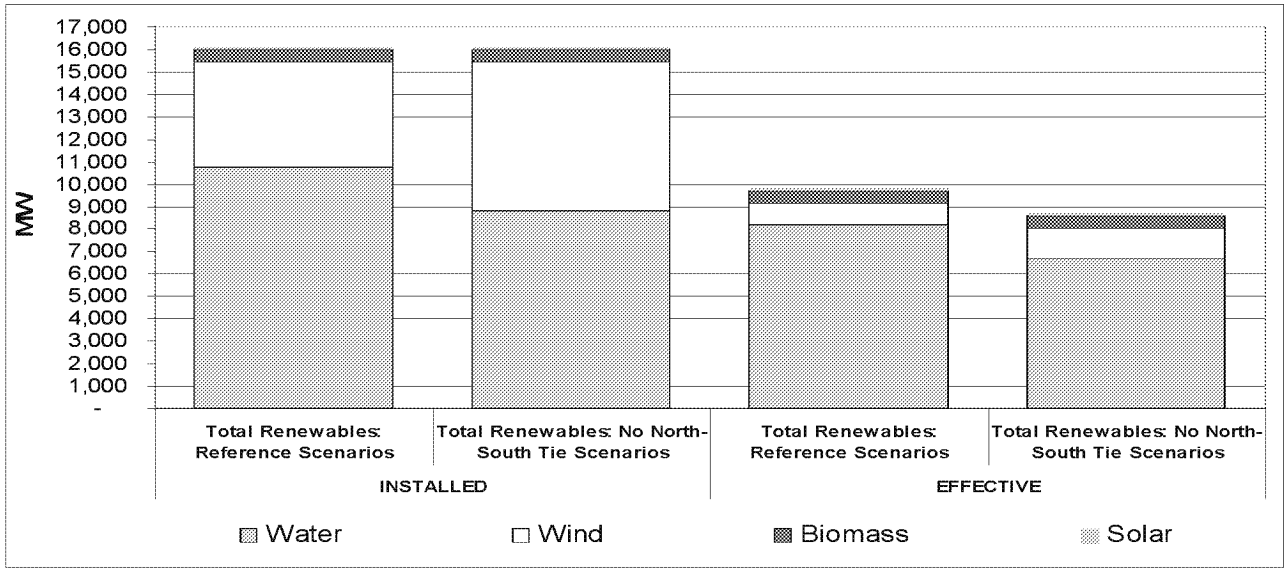
Resulting cumulative resources under Case 4A and 4B are illustrated in Figure 13, Figure 14, and Table 29 through Table 32 and Table 37 through Table 40 below. These changes all occur in 2016 or beyond, with sufficient lead time to make the necessary adjustments in the next IPSP.

Figure 10: Comparison of Planned Renewables under Reference and no-North-South Tie Scenarios (MW)



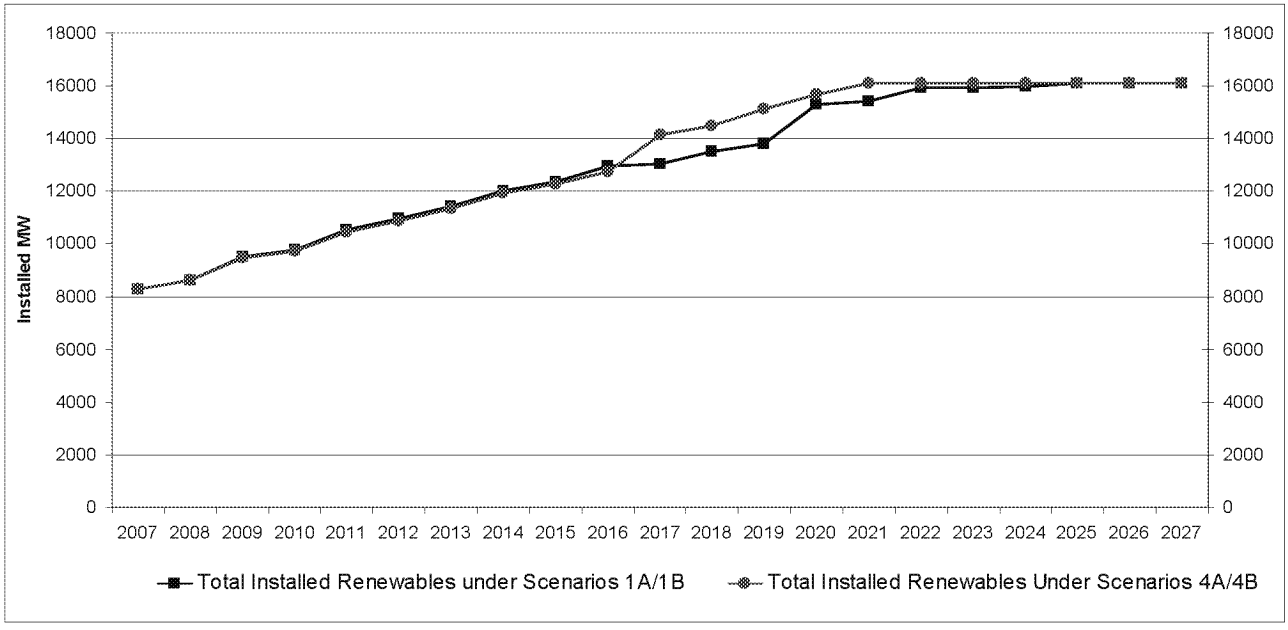
Source:

Figure 11: Comparison of Total Renewables under Reference and no-North-South Tie Scenarios (MW)



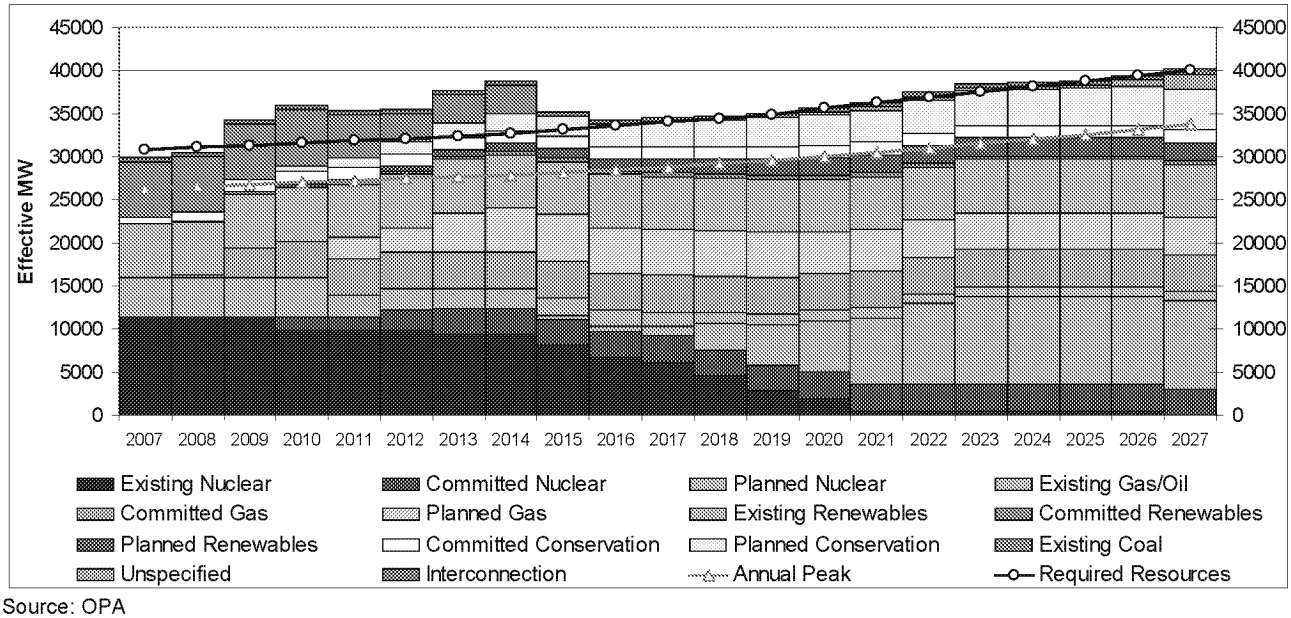
Source:

Figure 12: Comparison of Cumulative Total Renewables under Reference and no-North-South Tie Scenarios (Installed MW)



Source:

Figure 13: Case 4A Cumulative Resources (Effective MW)



Source: OPA

Table 29: Case 4A Cumulative Resources (Effective MW)

Effective MW	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Existing Nuclear	11,419	11,419	11,419	9,879	9,879	9,879	9,363	9,363	8,050	6,686	6,170	4,487	2,792	1,911	515	515	515	515	515	515	0
Committed Nuclear	0	0	0	1,500	1,500	2,270	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040
Planned Nuclear	0	0	0	0	0	0	0	0	516	516	1,032	3,045	4,593	5,990	7,673	9,368	10,249	10,249	10,249	10,249	10,249
Existing Gas/Oil	4,578	4,578	4,578	4,578	2,473	2,473	2,308	2,308	2,004	1,897	1,691	1,236	1,236	1,236	1,236	1,105	1,105	1,105	1,105	1,105	1,105
Committed Gas	0	281	3,431	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267
Planned Gas	0	0	0	0	2,455	2,905	4,507	5,057	5,361	5,361	5,361	5,361	5,361	4,836	4,836	4,311	4,311	4,311	4,311	4,311	4,311
Existing Renewables	6,129	6,129	6,129	6,129	6,129	6,129	6,129	6,129	6,129	6,129	6,129	6,129	6,129	6,129	6,129	6,129	6,129	6,129	6,129	6,129	6,129
Committed Renewables	4	115	317	408	408	408	408	408	408	408	408	408	408	408	408	408	408	408	408	408	408
Planned Renewables	11	25	58	58	303	584	742	982	1,143	1,364	1,660	1,740	1,880	2,074	2,161	2,161	2,161	2,161	2,161	2,161	2,161
Committed Conservation	755	1,006	1,375	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407
Planned Conservation	0	0	0	755	1,084	1,413	1,741	2,070	2,398	2,614	2,878	3,146	3,358	3,560	3,722	3,884	4,043	4,206	4,354	4,583	4,811
Existing Coal	6,434	6,434	6,434	6,434	4,969	3,293	3,293	3,293	0	0	0	0	0	0	0	0	0	0	0	0	0
Unspecified	0	0	0	0	0	0	0	0	0	0	0	0	50	350	350	350	350	350	350	750	1,725
Interconnection	500	500	500	500	500	500	500	500	500	500	500	500	500	500	505	500	500	500	500	500	500
Annual Peak	26,282	26,515	26,749	26,986	27,205	27,426	27,648	27,873	28,099	28,457	28,820	29,187	29,559	29,936	30,444	30,960	31,485	32,020	32,563	33,115	33,677
Required Resources	30,750	31,022	31,296	31,573	31,830	32,088	32,349	32,611	33,157	33,580	34,008	34,441	34,880	35,624	36,228	36,843	37,468	38,103	38,750	39,407	40,076

Source:

Table 30: Case 4A Cumulative Resources (Installed MW)

Installed MW	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Existing Nuclear	11,419	11,419	11,419	9,879	9,879	9,879	9,363	9,363	8,050	6,686	6,170	4,487	2,792	1,911	515	515	515	515	515	515	0
Committed Nuclear	0	0	0	1,500	1,500	2,270	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040
Planned Nuclear	0	0	0	0	0	0	0	0	516	516	1,032	3,045	4,593	5,990	7,673	9,368	10,249	10,249	10,249	10,249	10,249
Existing Gas/Oil	5,103	5,103	5,103	5,103	2,998	2,998	2,833	2,833	2,529	2,422	2,216	1,761	1,761	1,761	1,761	1,630	1,630	1,630	1,630	1,630	1,630
Committed Gas	0	281	3,431	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267
Planned Gas	0	0	0	0	2,455	2,905	4,507	5,057	5,361	5,361	5,361	5,361	5,361	4,836	4,836	4,311	4,311	4,311	4,311	4,311	4,311
Existing Renewables	8,258	8,258	8,258	8,258	8,258	8,258	8,258	8,258	8,258	8,258	8,258	8,258	8,258	8,258	8,258	8,258	8,258	8,258	8,258	8,258	8,258
Committed Renewables	5	331	1,158	1,415	1,415	1,415	1,415	1,415	1,415	1,415	1,415	1,415	1,415	1,415	1,415	1,415	1,415	1,415	1,415	1,415	1,415
Planned Renewables	16	36	81	81	855	1,260	1,729	2,335	2,692	3,104	4,492	4,826	5,461	6,035	6,456	6,456	6,456	6,456	6,456	6,456	6,456
Committed Conservation	755	1,006	1,375	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407
Planned Conservation	0	0	0	755	1,084	1,413	1,741	2,070	2,398	2,614	2,878	3,146	3,358	3,560	3,722	3,884	4,043	4,206	4,354	4,583	4,811
Existing Coal	6,434	6,434	6,434	6,434	4,969	3,293	3,293	3,293	0	0	0	0	0	0	0	0	0	0	0	0	0
Unspecified	0	0	0	0	0	0	0	0	0	0	0	0	50	350	350	350	350	350	350	750	1,725
Interconnection	500	500	500	500	500	500	500	500	500	500	500	500	500	500	505	500	500	500	500	500	500
Annual Peak	26,282	26,515	26,749	26,986	27,205	27,426	27,648	27,873	28,099	28,457	28,820	29,187	29,559	29,936	30,444	30,960	31,485	32,020	32,563	33,115	33,677
Required Resources	30,750	31,022	31,296	31,573	31,830	32,088	32,349	32,611	33,157	33,580	34,008	34,441	34,880	35,624	36,228	36,843	37,468	38,103	38,750	39,407	40,076

Source:

Table 31: Case 4A Cumulative Resources by Fuel Type (Installed MW)

Installed Total by Fuel	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Conservation	755	1,006	1,375	2,162	2,491	2,820	3,148	3,477	3,805	4,021	4,285	4,553	4,765	4,967	5,129	5,291	5,450	5,613	5,761	5,990	6,218
Wind	396	659	1,447	1,646	2,221	2,221	2,594	3,005	3,231	3,466	4,841	5,159	5,779	6,234	6,655	6,655	6,655	6,655	6,655	6,655	6,655
Biomass	79	89	89	89	89	150	190	233	301	462	475	488	492	539	539	539	539	539	539	539	539
Solar	0	29	68	88	88	88	88	88	88	88	88	88	88	88	88	88	88	88	88	88	88
Hydro	7,804	7,848	7,893	7,931	8,130	8,474	8,530	8,682	8,745	8,761	8,761	8,763	8,774	8,847	8,847	8,847	8,847	8,847	8,847	8,847	8,847
Nuclear	11,419	11,419	11,419	11,379	11,379	12,149	12,403	12,403	11,606	10,242	10,242	10,572	10,425	10,941	11,228	12,923	13,804	13,804	13,804	13,804	13,289
Gas/Oil	5,103	5,384	8,534	9,370	9,720	10,170	11,607	12,157	12,157	12,050	11,844	11,389	11,389	10,864	10,864	10,208	10,208	10,208	10,208	10,208	10,208
Coal	6,434	6,434	6,434	6,434	4,969	3,293	3,293	3,293	0	0	0	0	0	0	0	0	0	0	0	0	0
Interconnection	500	500	500	500	500	500	500	500	500	500	500	500	500	500	505	500	500	500	500	500	500
Unspecified	0	0	0	0	0	0	0	0	0	0	0	0	50	350	350	350	350	350	350	750	1,725

Source:

Table 32: Case 4A Cumulative Resources by Fuel Type (Effective MW)

Effective Total by Fuel	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Conservation	755	1,006	1,375	2,162	2,491	2,820	3,148	3,477	3,805	4,021	4,285	4,553	4,765	4,967	5,129	5,291	5,450	5,613	5,761	5,990	6,218
Wind	82	136	298	339	457	457	534	619	666	714	997	1,063	1,191	1,284	1,371	1,371	1,371	1,371	1,371	1,371	1,371
Biomass	79	89	89	89	89	150	190	233	301	462	475	488	492	539	539	539	539	539	539	539	539
Solar	0	29	68	88	88	88	88	88	88	88	88	88	88	88	88	88	88	88	88	88	88
Hydro	5,983	6,015	6,048	6,079	6,206	6,425	6,467	6,579	6,625	6,637	6,637	6,638	6,647	6,700	6,700	6,700	6,700	6,700	6,700	6,700	6,700
Nuclear	11,419	11,419	11,419	11,379	11,379	12,149	12,403	12,403	11,606	10,242	10,242	10,572	10,425	10,941	11,228	12,923	13,804	13,804	13,804	13,804	13,289
Gas/Oil	4,578	4,859	8,009	8,845	9,195	9,645	11,082	11,632	11,632	11,525	11,319	10,864	10,864	10,339	10,339	9,683	9,683	9,683	9,683	9,683	9,683
Coal	6,434	6,434	6,434	6,434	4,969	3,293	3,293	3,293	0	0	0	0	0	0	0	0	0	0	0	0	0
Interconnection	500	500	500	500	500	500	500	500	500	500	500	500	500	500	505	500	500	500	500	500	500
Unspecified	0	0	0	0	0	0	0	0	0	0	0	0	50	350	350	350	350	350	350	750	1,725

Source:

Q. What is the estimated energy production under Case 4A?

A. Energy production and Conservation under Case 4A is summarized in Table 33 and Table 34. By 2027, nuclear resources produce 98 TWh, renewables and Conservation resources generate/conserve 92 TWh, and gas-fired resources produce 19 TWh.

Table 33: Case 4A Energy Production (TWh)

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Conservation	4	5	9	12	13	15	17	19	20	21	22	23	24	25	26	27	28	28	30	31
Renewables	38	40	41	43	45	46	48	49	51	54	55	57	60	60	61	61	61	61	61	61
Nuclear	83	80	80	82	90	92	90	85	74	74	77	74	78	81	93	101	101	101	102	98
Gas	15	17	18	18	18	19	19	22	24	23	21	22	19	20	17	15	15	16	17	19
Coal	29	28	27	21	16	15	15	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	168	170	175	176	182	187	188	175	169	172	175	176	181	187	197	204	205	206	209	209

Source: OPA

Table 34: Case 4A Energy Production as Percentage of Total

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Conservation	2%	3%	5%	7%	7%	8%	9%	11%	12%	12%	13%	13%	13%	13%	13%	13%	14%	14%	14%	15%
Renewables	22%	24%	24%	24%	25%	25%	25%	28%	30%	31%	32%	32%	33%	32%	31%	30%	30%	30%	29%	29%
Nuclear	49%	47%	45%	47%	49%	49%	48%	49%	44%	43%	44%	42%	43%	43%	47%	50%	49%	49%	49%	47%
Gas	9%	10%	10%	10%	10%	10%	10%	13%	14%	13%	12%	13%	11%	11%	8%	7%	7%	8%	8%	9%
Coal	17%	17%	16%	12%	9%	8%	8%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Total	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

Source: OPA

Q. How do the resources in Case 4A compare to those in Case 1A?

A. In Case 4A, installed resources are higher than in Case 1A for the period from 2017 to 2027. This is because more wind capacity is required in the south to compensate for the loss of hydroelectric capacity in the north. Additional "unspecified" gas-fired generation is also required beginning in 2020 to supplement wind in the south.

Table 35: Comparison of Case 4A to Case 1A (Installed MW)

Installed Total by Fuel	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Conservation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	0	0	0	0	0	0	0	0	0	0	1,300	1,182	1,656	1,549	1,970	1,970	1,970	1,970	1,970	1,970	1,970
Biomass	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hydro	0	0	0	0	0	0	0	0	0	-174	-188	-193	-324	-1,112	-1,259	-1,760	-1,760	-1,789	-1,924	-1,924	-1,924
Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Coal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Unspecified	0	0	0	0	0	0	0	0	0	0	0	-250	-200	100	100	100	100	100	100	500	1,075
Total	0	0	0	0	0	0	0	0	0	-174	1,112	739	1,132	537	811	310	310	281	146	546	1,121

Source: OPA

Q. How does energy production under Case 4A compare to production under Case 1A?

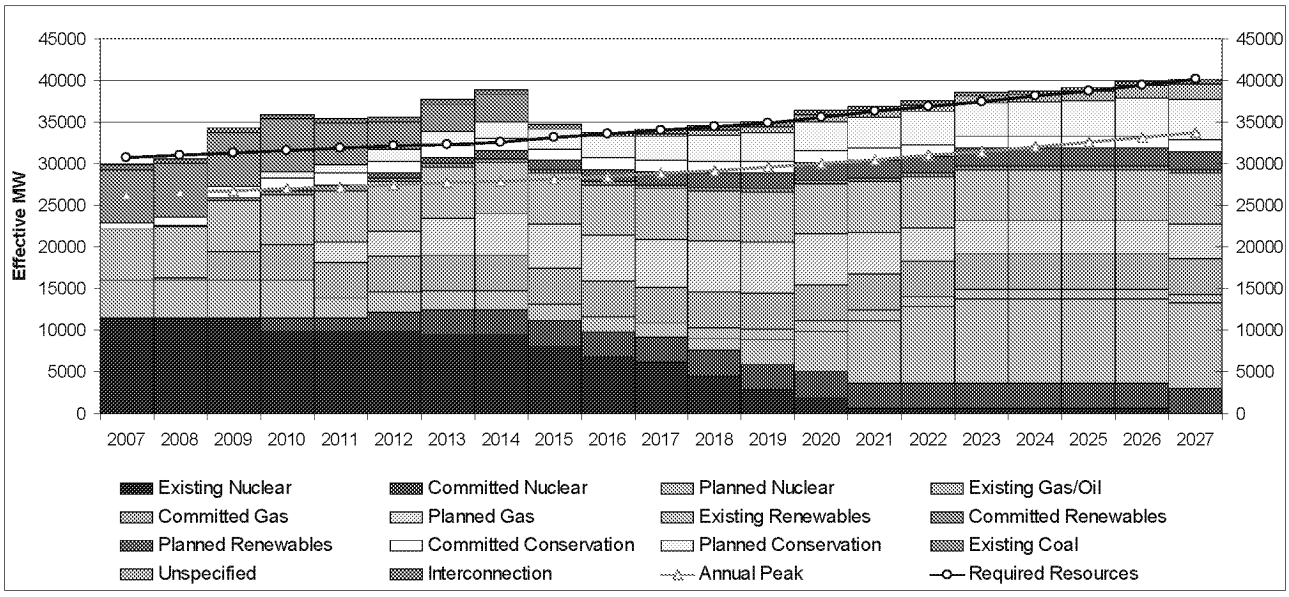
A. Case 4A sees about 2 TWh less renewable production by 2027 than Case 1A. Also by 2027, Case 4A sees higher levels of natural gas-fired production and imports.

Table 36: Comparison of Case 4A to Case 1A (TWh)

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Conservation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Renewables	0	0	0	0	0	0	0	0	0	3	2	3	0	1	-1	-1	-1	-2	-2	-2
Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gas	0	0	0	0	0	0	0	0	0	-1	-1	-1	0	0	0	1	1	1	1	1
Coal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Imports	0	0	0	0	0	0	0	0	0	-1	-1	-1	0	0	0	0	0	1	1	1

Source: OPA

Figure 14: Case 4B Cumulative Resources (Effective MW)



Source: OPA

Table 37: Case 4B Cumulative Resources (Effective MW)

Effective MW	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Existing Nuclear	11,419	11,419	11,419	9,879	9,879	9,879	9,363	9,363	8,050	6,686	6,170	4,487	2,792	1,911	515	515	515	515	515	515	0
Committed Nuclear	0	0	0	1,500	1,500	2,270	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040
Planned Nuclear	0	0	0	0	0	0	0	0	0	0	0	1,497	3,045	4,926	7,609	9,304	10,185	10,185	10,185	10,185	10,185
Existing Gas/Oil	4,578	4,578	4,578	4,578	2,473	2,473	2,308	2,308	2,004	1,897	1,691	1,236	1,236	1,236	1,236	1,105	1,105	1,105	1,105	1,105	1,105
Committed Gas	0	281	3,431	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267
Planned Gas	0	0	0	0	2,455	2,905	4,507	5,057	5,361	5,467	5,673	6,129	6,129	6,129	5,079	4,029	4,029	4,029	4,029	4,029	4,160
Existing Renewables	6,129	6,129	6,129	6,129	6,129	6,129	6,129	6,129	6,129	6,129	6,129	6,129	6,129	6,129	6,129	6,129	6,129	6,129	6,129	6,129	6,129
Committed Renewables	4	115	317	408	408	408	408	408	408	408	408	408	408	408	408	408	408	408	408	408	408
Planned Renewables	11	25	58	58	303	584	742	982	1,143	1,364	1,660	1,740	1,880	2,074	2,161	2,161	2,161	2,161	2,161	2,161	2,161
Committed Conservation	755	1,006	1,375	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407
Planned Conservation	0	0	0	755	1,084	1,413	1,741	2,070	2,398	2,614	2,878	3,146	3,358	3,560	3,722	3,884	4,043	4,206	4,354	4,583	4,811
Existing Coal	6,434	6,434	6,434	6,434	4,969	3,293	3,293	3,293	0	0	0	0	0	0	0	0	0	0	0	0	0
Unspecified	0	0	0	0	0	0	0	0	0	0	325	575	825	825	825	825	825	825	1,125	1,575	1,925
Interconnection	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500
Annual Peak	26,282	26,515	26,749	26,986	27,205	27,426	27,648	27,873	28,099	28,457	28,820	29,187	29,559	29,936	30,444	30,960	31,485	32,020	32,563	33,115	33,677
Required Resources	30,750	31,022	31,296	31,573	31,830	32,088	32,349	32,611	33,157	33,580	34,008	34,441	34,880	35,624	36,228	36,843	37,468	38,103	38,750	39,407	40,076

Source: OPA

Table 38: Case 4B Cumulative Resources (Installed MW)

Installed MW	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Existing Nuclear	11,419	11,419	11,419	9,879	9,879	9,879	9,363	9,363	8,050	6,686	6,170	4,487	2,792	1,911	515	515	515	515	515	515	0
Committed Nuclear	0	0	0	1,500	1,500	2,270	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040
Planned Nuclear	0	0	0	0	0	0	0	0	0	0	0	1,497	3,045	4,926	7,609	9,304	10,185	10,185	10,185	10,185	10,185
Existing Gas/Oil	5,103	5,103	5,103	5,103	2,998	2,998	2,833	2,833	2,529	2,422	2,216	1,761	1,761	1,761	1,761	1,630	1,630	1,630	1,630	1,630	1,630
Committed Gas	0	281	3,431	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267	4,267
Planned Gas	0	0	0	0	2,455	2,905	4,507	5,057	5,361	5,467	5,673	6,129	6,129	6,129	5,079	4,029	4,029	4,029	4,029	4,029	4,160
Existing Renewables	8,258	8,258	8,258	8,258	8,258	8,258	8,258	8,258	8,258	8,258	8,258	8,258	8,258	8,258	8,258	8,258	8,258	8,258	8,258	8,258	8,258
Committed Renewables	5	331	1,158	1,415	1,415	1,415	1,415	1,415	1,415	1,415	1,415	1,415	1,415	1,415	1,415	1,415	1,415	1,415	1,415	1,415	1,415
Planned Renewables	16	36	81	81	855	1,260	1,729	2,335	2,692	3,104	4,492	4,826	5,461	6,035	6,456	6,456	6,456	6,456	6,456	6,456	6,456
Committed Conservation	755	1,006	1,375	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407	1,407
Planned Conservation	0	0	0	755	1,084	1,413	1,741	2,070	2,398	2,614	2,878	3,146	3,358	3,560	3,722	3,884	4,043	4,206	4,354	4,583	4,811
Existing Coal	6,434	6,434	6,434	6,434	4,969	3,293	3,293	3,293	0	0	0	0	0	0	0	0	0	0	0	0	0
Unspecified	0	0	0	0	0	0	0	0	0	0	325	575	825	825	825	825	825	825	1,125	1,575	1,925
Interconnection	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500
Annual Peak	26,282	26,515	26,749	26,986	27,205	27,426	27,648	27,873	28,099	28,457	28,820	29,187	29,559	29,936	30,444	30,960	31,485	32,020	32,563	33,115	33,677
Required Resources	30,750	31,022	31,296	31,573	31,830	32,088	32,349	32,611	33,157	33,580	34,008	34,441	34,880	35,624	36,228	36,843	37,468	38,103	38,750	39,407	40,076

Source: OPA

Table 39: Case 4B Cumulative Resources by Fuel Type (Installed MW)

Installed Total by Fuel	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Conservation	755	1,006	1,375	2,162	2,491	2,820	3,148	3,477	3,805	4,021	4,285	4,553	4,765	4,967	5,129	5,291	5,450	5,613	5,761	5,990	6,218
Wind	396	659	1,447	1,646	2,221	2,221	2,594	3,005	3,231	3,466	4,841	5,159	5,779	6,234	6,655	6,655	6,655	6,655	6,655	6,655	6,655
Biomass	79	89	89	89	89	150	190	233	301	462	475	488	492	539	539	539	539	539	539	539	539
Solar	0	29	68	88	88	88	88	88	88	88	88	88	88	88	88	88	88	88	88	88	88
Hydro	7,804	7,848	7,893	7,931	8,130	8,474	8,530	8,682	8,745	8,761	8,761	8,763	8,774	8,847	8,847	8,847	8,847	8,847	8,847	8,847	8,847
Nuclear	11,419	11,419	11,419	11,379	11,379	12,149	12,403	12,403	11,090	9,726	9,210	9,024	8,877	9,877	11,164	12,859	13,740	13,740	13,740	13,740	13,225
Gas/Oil	5,103	5,384	8,534	9,370	9,720	10,170	11,607	12,157	12,157	12,157	12,157	12,157	12,157	12,157	11,107	9,926	9,926	9,926	9,926	9,926	10,057
Coal	6,434	6,434	6,434	6,434	4,969	3,293	3,293	3,293	0	0	0	0	0	0	0	0	0	0	0	0	0
Interconnection	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500
Unspecified	0	0	0	0	0	0	0	0	0	0	325	575	825	825	825	825	825	825	1,125	1,575	1,925

Source: OPA

Table 40: Case 4B Cumulative Resources by Fuel Type (Effective MW)

Effective Total by Fuel	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Conservation	755	1,006	1,375	2,162	2,491	2,820	3,148	3,477	3,805	4,021	4,285	4,553	4,765	4,967	5,129	5,291	5,450	5,613	5,761	5,990	6,218
Wind	82	136	298	339	457	457	534	619	666	714	997	1,063	1,191	1,284	1,371	1,371	1,371	1,371	1,371	1,371	1,371
Biomass	79	89	89	89	89	150	190	233	301	462	475	488	492	539	539	539	539	539	539	539	539
Solar	0	29	68	88	88	88	88	88	88	88	88	88	88	88	88	88	88	88	88	88	88
Hydro	5,983	6,015	6,048	6,079	6,206	6,425	6,467	6,579	6,625	6,637	6,637	6,638	6,647	6,700	6,700	6,700	6,700	6,700	6,700	6,700	6,700
Nuclear	11,419	11,419	11,419	11,379	11,379	12,149	12,403	12,403	11,090	9,726	9,210	9,024	8,877	9,877	11,164	12,859	13,740	13,740	13,740	13,740	13,225
Gas/Oil	4,578	4,859	8,009	8,845	9,195	9,645	11,082	11,632	11,632	11,632	11,632	11,632	11,632	11,632	10,582	9,401	9,401	9,401	9,401	9,401	9,532
Coal	6,434	6,434	6,434	6,434	4,969	3,293	3,293	3,293	0	0	0	0	0	0	0	0	0	0	0	0	0
Interconnection	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500
Unspecified	0	0	0	0	0	0	0	0	0	0	325	575	825	825	825	825	825	825	1,125	1,575	1,925

Source: OPA

Q. What is the estimated energy production under Case 4B?

A. Energy production and Conservation under Case 4B is summarized in Table 41 and Table 42. By 2027, nuclear resources produce 100 TWh, renewables and Conservation resources generate/conserve 92 TWh, and gas-fired resources produce 19 TWh.

Table 41: Case 4B Energy Production (TWh)

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Conservation	4	5	9	12	13	15	17	19	20	21	22	23	24	25	26	27	28	28	30	31
Renewables	38	40	41	43	45	46	48	49	51	54	55	57	60	60	61	61	61	61	61	61
Nuclear	83	80	80	82	90	92	90	82	71	68	66	64	71	81	95	102	103	102	104	100
Gas	15	17	18	18	18	19	19	22	26	26	25	26	23	23	16	15	15	15	17	19
Coal	29	28	27	21	16	15	15	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	168	170	175	176	182	187	188	172	167	169	168	170	178	190	198	205	207	207	211	211

Source: OPA

Table 42: Case 4B Energy Production as Percentage of Total

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Conservation	2%	3%	5%	7%	7%	8%	9%	11%	12%	12%	13%	14%	14%	13%	13%	13%	13%	14%	14%	15%
Renewables	22%	24%	24%	24%	25%	25%	25%	29%	30%	32%	33%	33%	34%	32%	31%	30%	30%	29%	29%	29%
Nuclear	49%	47%	45%	47%	49%	49%	48%	48%	42%	40%	39%	37%	40%	43%	48%	50%	50%	49%	49%	48%
Gas	9%	10%	10%	10%	10%	10%	10%	13%	15%	15%	15%	15%	13%	12%	8%	7%	7%	7%	8%	9%
Coal	17%	17%	16%	12%	9%	8%	8%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Total	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

Source: OPA

Q. How does energy production under Case 4B compare to production under Case 1B?

A. Case 4B sees about 2 TWh less renewable production by 2027 than Case 1A. Also by 2027, Case 4B sees higher levels of natural gas-fired production and imports.

Table 43: Comparison of Case 4B: Case 1B (TWh)

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Conservation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Renewables	0	0	0	0	0	0	0	0	0	3	2	3	0	1	-1	-1	-1	-2	-2	-2
Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gas	0	0	0	0	0	0	0	0	0	-1	-1	-1	0	0	0	1	1	1	1	1
Coal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Imports	0	0	0	0	0	0	0	0	0	-1	-1	-1	0	0	0	0	0	0	0	1

Source: OPA

Q. How does energy production under Case 4B compare to production under Case 4A?

A. As illustrated in Table 44, Case 4B sees less production from nuclear resources than Case 2A between 2015 and 2020, but sees more nuclear production between 2022 and 2027. Case 2B sees more natural gas-fired production between 2016 and 2021 and more imports between 2015 and 2020.

Imports are greater between 2015 and 2020, though decrease as of 2021.

Table 44: Comparison of Case 4B: Case 4A (TWh)

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Conservation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Renewables	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Nuclear	0	0	0	0	0	0	0	-4	-4	-7	-10	-10	-7	0	1	1	2	1	2	2
Gas	0	0	0	0	0	0	0	0	2	3	4	4	4	3	0	0	0	0	0	0
Coal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Imports	0	0	0	0	0	0	0	1	1	2	4	4	1	-1	0	0	0	0	-1	-1

Source: OPA

Q. Do the energy production simulations for Cases 4A and 4B result in any unsupplied demand?

A. No. Cases 4A and 4B do not result in any unsupplied demand.

Q. What do Cases 4A and 4B demonstrate?

A. Cases 4A and 4B demonstrate that it is feasible to adapt the Plan to reliably meet requirements under circumstances in which major transmission to incorporate northern renewables is not implemented. Cases 4A and 4B also demonstrate that waterpower resources provide a higher effective capacity contribution compared to wind resources.

Q. What is the estimated range of requirements across the scenarios?

A. The cases described above and in Exhibit D-9-1 suggest a range of potential requirements for different resource types, depending on the particular set of conditions. This range of requirements is summarized in Table 45 from the perspective of installed capacity (MW) and energy (TWh).

Table 45: Range of Resource Requirements across eight Scenarios

Resource	Range (Installed MW)	Range (TWh)
Conservation	6,200 - 9,400	31 - 46
Renewables	15,700 - 16,000	61 - 63
Nuclear	11,000 - 13,300	89 - 104
Natural Gas	8,900 - 12,000	13 - 32
Unspecified	250 - 4,300	

Source: OPA

Q. Range of Requirements for Installed Capacity (MW)

Cases with no Pickering B refurbishment typically see a larger requirement for both natural gas-fired and unspecified resources. Cases with higher load growth also result in additional requirements.

In contrast, a lower requirement for natural gas-fired and unspecified resources is seen in cases in which Pickering B is refurbished as well as in those cases which are premised on either reference load and conservation forecasts or on higher amounts of Conservation. The same is true with respect to nuclear resources: lower demand growth and/or higher Conservation could either defer or reduce nuclear requirements. Conversely, higher demand growth could result in additional nuclear requirements.

The ranges outlined in Table 45 reflect requirements across the eight discrete cases described. While the ranges relate to the specific uncertainties described in the scenarios, they are also expected to address, to varying degrees, other uncertainties not specifically considered. However, it is important to recognize that requirements could be greater or lesser in the event that a number of the discrete conditions or perturbations occur simultaneously.

Moreover, resource requirements can also vary as a result of less success in the implementation of committed and planned resources (whether in terms of timing, quantities, or both) and poorer operational performance of existing, committed and planned resources.

Q. Range of Requirements for Energy (TWh)

Table 46, Table 47 and Figure 15 through Figure 20 summarize the range of energy production and imports across the eight cases.

It will be seen that cases with no Pickering B refurbishment result in up to 10 TWh less nuclear production per year between 2015 and 2020. Consequently, they see higher production from natural gas-fired resources in addition to higher amounts of imports. Beyond 2020 or so, cases with no Pickering B refurbishment see about 2 TWh more output from nuclear resources, as the non-refurbished units are eventually replaced with new units.

Cases where Pickering B is refurbished show relatively lower amounts of gas-fired production than cases in which Pickering B is not refurbished, but still see significantly higher amounts of gas-fired production relative to today's levels. This is because even though nuclear production under the "A" cases is higher than nuclear production under the "B" cases, total nuclear production under the "A" cases between 2015 and 2020 is still about 10 TWh less than it is today.

Cases with higher load growth also see greater energy production from gas-fired resources and imports, as do cases with lower production from renewables. In contrast, cases with higher Conservation see lower production from gas-fired resources and imports. Confidence related to estimates of imports is lower than confidence related to estimates of production from Ontario-based resources, as discussed below.

In general, the above results suggest that the amount of production from natural gas-fired resources is contingent on the performance of Conservation, renewable, and nuclear resources as well as on load growth. In effect, natural gas resources and imports are shown to provide the future swing capability that has historically been provided by coal.

Table 48 through Table 55 further illustrate that utilization (as indicated by annual capacity factors) of gas-fired resources is sensitive to the availability of Conservation, renewable and nuclear resources as well as to rate of load growth. Among the gas-fired

resources, utilization of combined cycle plant in particular is seen to show the widest range of swing or variability, depending on the particular scenario. In this sense, combined cycle plant represents the most significant source of "energy insurance" among the resources considered.[3] It may be worth exploring the possibility of deriving some of this energy insurance from Combined Heat and Power ("CHP") resources, particularly for conditions which see lower amounts of baseload production.

As with the installed capacity ranges identified in Table 45, the energy production ranges identified in Table 46 reflect requirements across the eight discrete cases described. It is once again worth noting that requirements could be greater or lesser in the event that a number of the discrete conditions occur at the same time or wherever there might be less success in the implementation of committed and planned resources and/or poorer operational performance of existing, committed and planned resources.

Q. How should results related to imports be interpreted?

Confidence related to estimates of imports is lower than confidence related to estimates of production from Ontario-based resources. Estimating imports requires assumptions about specific conditions within neighbouring markets over long periods of time, resulting in a considerable margin of uncertainty around specific results.

A. Figure 20 illustrates maximum and minimum levels of imports across the eight cases. Uncertainty around imports in the period to 2014 is further increased by the fact that both coal-fired resources and coal replacement resources are represented for purposes of production simulation. In practice, it is expected that coal-fired resources will be removed from service as sufficient replacement resources are implemented. Uncertainty around imports in the mid- to long term is increased by uncertainty related to long term demand growth and resource implementation and performance. Results

[3] It will be seen that CCGT and SCGT utilization is relatively low in the period when coal is still in service (i.e., prior to the end of 2014), though reaches higher levels beyond 2015. It is likely that estimates of gas-fired utilization prior to 2015 are somewhat understated, on account of both coal-fired resources and planned resources being simulated as simultaneously in-service. In practice it is expected that the requirement for insurance resource such as coal would be reduced once planned resources are implemented. This might tend to increase utilization of resources such as CCGT and SCGT.

around imports should be interpreted directionally, for example, as illustrating greater requirement for imports during periods of lower expected energy production capability (such as between 2015 and 2020).

Table 46: Range of Energy Production across eight Scenarios (TWh)

		2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Conservation	Min	4	5	9	12	13	15	17	19	20	21	22	23	24	25	26	27	28	28	30	31
	Max	4	5	10	17	19	22	25	28	30	32	33	35	36	38	39	40	42	43	45	46
Renewables	Min	38	40	41	43	45	46	48	49	51	51	53	53	59	60	61	61	61	61	61	61
	Max	38	40	41	43	45	46	48	49	52	54	55	57	60	60	62	62	63	63	63	63
Nuclear	Min	83	80	80	82	90	92	90	82	71	68	66	64	64	67	80	87	88	87	89	85
	Max	83	80	80	82	90	92	90	85	74	74	77	74	78	81	95	102	103	102	104	100
Gas	Min	15	17	18	17	17	17	17	19	21	20	18	20	18	19	15	13	13	13	15	16
	Max	15	17	18	18	18	19	19	23	28	29	29	32	27	27	20	19	19	21	24	28
Coal	Min	29	28	27	21	14	13	14	0	0	0	0	0	0	0	0	0	0	0	0	0
	Max	29	29	27	22	16	15	16	0	0	0	0	0	0	0	0	0	0	0	0	0
Imports	Min	7	5	4	4	2	1	1	2	5	6	8	8	7	6	3	2	2	2	2	3
	Max	8	6	4	6	3	2	2	7	12	14	16	18	14	12	8	6	8	9	10	12

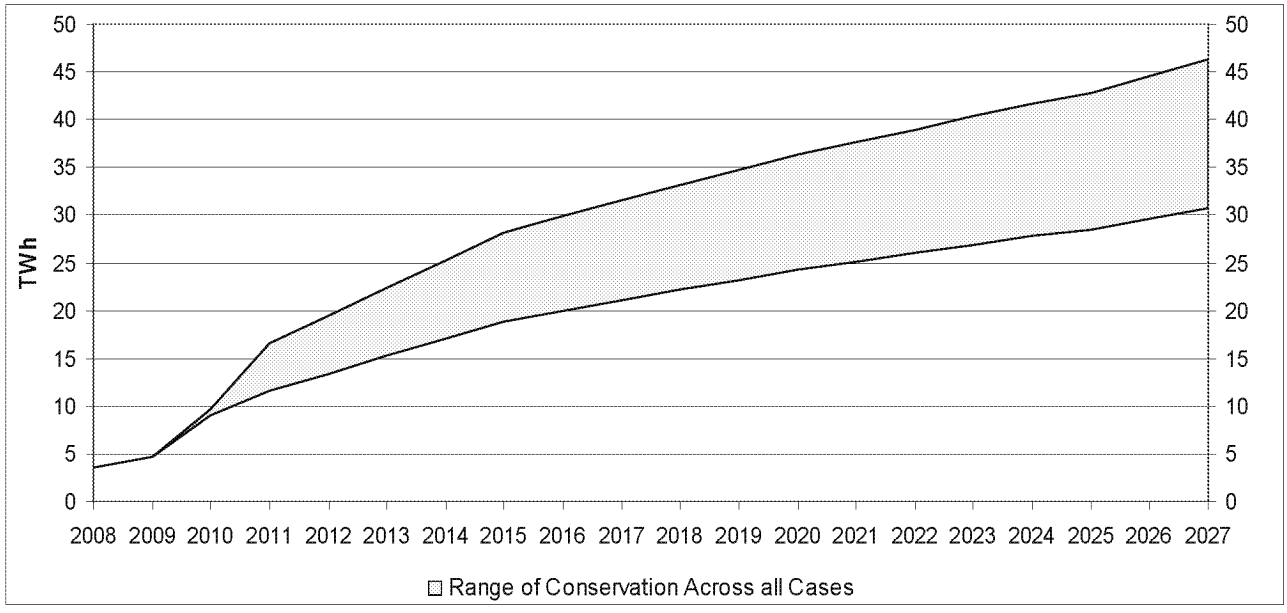
Source: OPA

Table 47: Energy Production across eight Scenarios (TWh)

		2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Conservation	1A	4	5	9	12	13	15	17	19	20	21	22	23	24	25	26	27	28	28	30	31
	1B	4	5	9	12	13	15	17	19	20	21	22	23	24	25	26	27	28	28	30	31
	2A	4	5	9	12	13	15	17	19	20	21	22	23	24	25	26	27	28	28	30	31
	2B	4	5	9	12	13	15	17	19	20	21	22	23	24	25	26	27	28	28	30	31
	3A	4	5	10	17	19	22	25	28	30	32	33	35	36	38	39	40	42	43	45	46
	3B	4	5	10	17	19	22	25	28	30	32	33	35	36	38	39	40	42	43	45	46
	4A	4	5	9	12	13	15	17	19	20	21	22	23	24	25	26	27	28	28	30	31
	4B	4	5	9	12	13	15	17	19	20	21	22	23	24	25	26	27	28	28	30	31
Renewables	1A	38	40	41	43	45	46	48	49	51	51	53	54	59	60	62	62	62	63	63	63
	1B	38	40	41	43	45	46	48	49	51	51	53	53	59	60	62	62	62	63	63	63
	2A	38	40	41	43	45	46	48	49	51	51	53	54	59	60	62	62	63	63	63	63
	2B	38	40	41	43	45	46	48	49	51	51	53	54	59	60	62	62	62	63	63	63
	3A	38	40	41	43	45	46	48	49	51	52	53	54	60	60	62	62	63	63	63	63
	3B	38	40	41	43	45	46	48	49	52	52	53	54	60	60	62	62	63	63	63	63
	4A	38	40	41	43	45	46	48	49	51	54	55	57	60	60	61	61	61	61	61	61
	4B	38	40	41	43	45	46	48	49	51	54	55	57	60	60	61	61	61	61	61	61
Nuclear	1A	83	80	80	82	90	92	90	85	74	74	77	74	78	81	93	101	101	101	102	98
	1B	83	80	80	82	90	92	90	82	71	68	66	64	71	81	95	102	103	102	104	100
	2A	83	80	80	82	90	92	90	85	74	74	77	74	78	81	93	101	101	101	102	98
	2B	83	80	80	82	90	92	90	82	71	68	66	64	71	81	95	102	103	102	104	100
	3A	83	80	80	82	90	92	90	85	74	74	72	64	68	71	83	91	91	91	91	87
	3B	83	80	80	82	90	92	90	82	71	68	66	64	64	67	80	87	88	87	89	85
	4A	83	80	80	82	90	92	90	85	74	74	77	74	78	81	93	101	101	101	102	98
	4B	83	80	80	82	90	92	90	82	71	68	66	64	71	81	95	102	103	102	104	100
Gas	1A	15	17	18	18	18	19	19	22	24	23	22	23	19	20	16	15	14	15	16	18
	1B	15	17	18	18	18	19	19	22	26	26	25	27	23	23	16	15	14	15	16	18
	2A	15	17	18	18	18	19	19	23	27	27	26	28	23	25	20	19	19	21	24	28
	2B	15	17	18	18	18	19	19	23	28	29	29	32	27	27	20	19	19	20	22	27
	3A	15	17	18	17	17	17	17	20	21	20	18	20	18	19	15	13	13	13	15	16
	3B	15	17	18	17	17	17	17	19	22	22	21	22	21	22	15	14	13	14	15	17
	4A	15	17	18	18	18	19	19	22	24	23	21	22	19	20	17	15	15	16	17	19
	4B	15	17	18	18	18	19	19	22	26	26	25	26	23	23	16	15	15	15	17	19
Coal	1A	29	28	27	21	16	14	15	0	0	0	0	0	0	0	0	0	0	0	0	0
	1B	29	28	27	21	16	14	15	0	0	0	0	0	0	0	0	0	0	0	0	0
	2A	29	29	27	22	16	15	16	0	0	0	0	0	0	0	0	0	0	0	0	0
	2B	29	29	27	22	16	15	16	0	0	0	0	0	0	0	0	0	0	0	0	0
	3A	29	28	27	21	14	13	14	0	0	0	0	0	0	0	0	0	0	0	0	0
	3B	29	28	27	21	14	13	14	0	0	0	0	0	0	0	0	0	0	0	0	0
	4A	29	28	27	21	16	15	15	0	0	0	0	0	0	0	0	0	0	0	0	0
	4B	29	28	27	21	16	15	15	0	0	0	0	0	0	0	0	0	0	0	0	0
Imports	1A	7	5	4	5	3	2	2	4	8	9	9	10	8	7	3	2	2	3	3	4
	1B	7	5	4	5	3	2	2	5	10	11	13	14	9	6	3	2	2	3	3	3
	2A	8	6	4	6	3	2	2	6	11	12	12	13	13	12	8	6	8	9	10	12
	2B	8	6	4	6	3	2	2	7	12	14	16	18	14	10	7	6	7	9	9	11
	3A	7	6	4	4	2	1	1	2	5	6	8	11	7	6	3	2	2	2	2	3
	3B	7	6	4	4	2	1	1	3	6	7	9	10	8	7	3	2	2	3	3	4
	4A	7	6	4	5	3	2	2	4	9	8	8	8	8	7	4	3	3	3	4	5
	4B	7	6	4	5	3	2	2	5	10	10	12	13	9	6	3	3	3	3	3	4

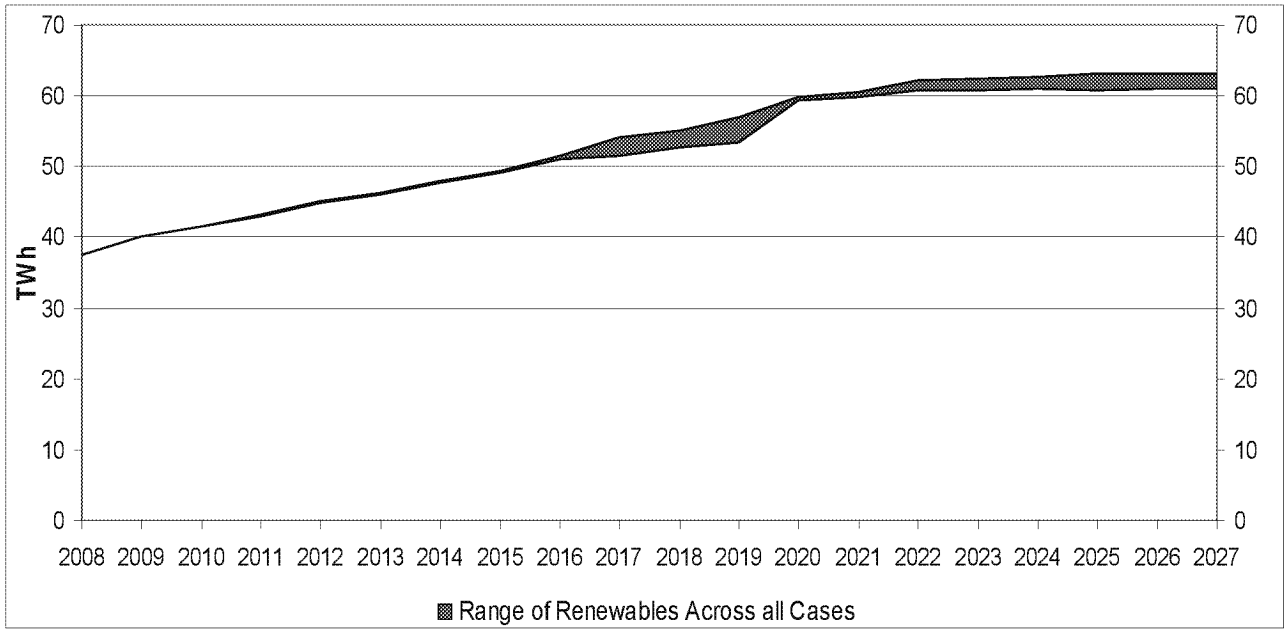
Source: OPA

Figure 15: Range of Conservation across eight Scenarios (TWh)



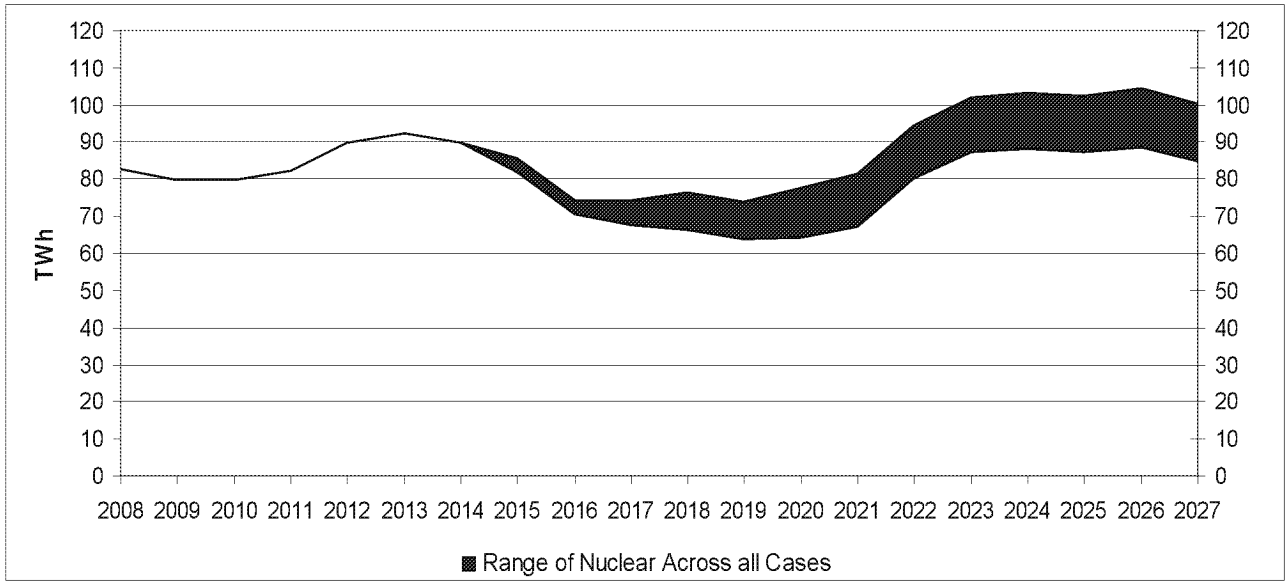
Source: OPA

Figure 16: Range of Renewable Production across eight Scenarios (TWh)



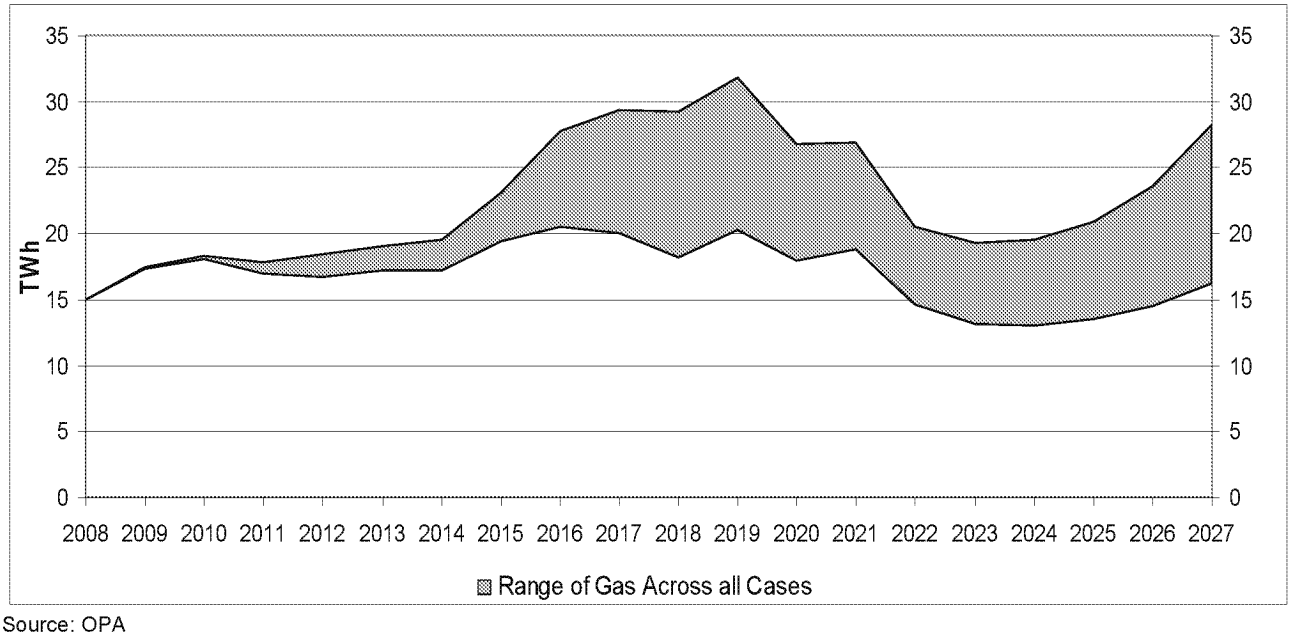
Source: OPA

Figure 17: Range of Nuclear Production across eight Scenarios (TWh)



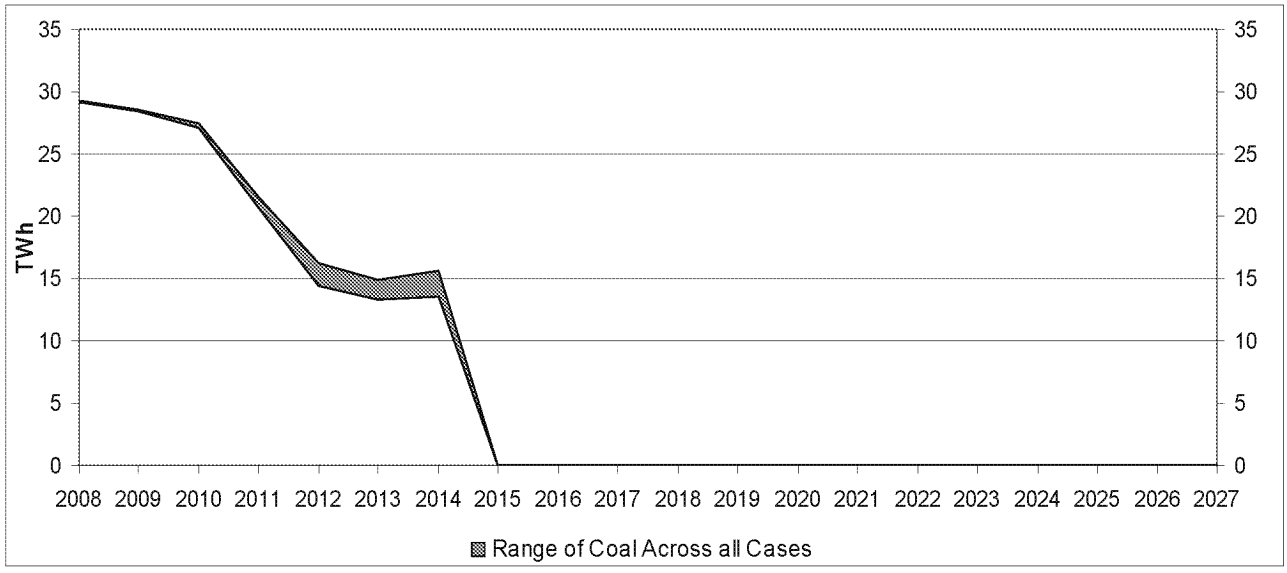
Source: OPA

Figure 18: Range of Natural Gas-Fired Production across eight Scenarios (TWh)



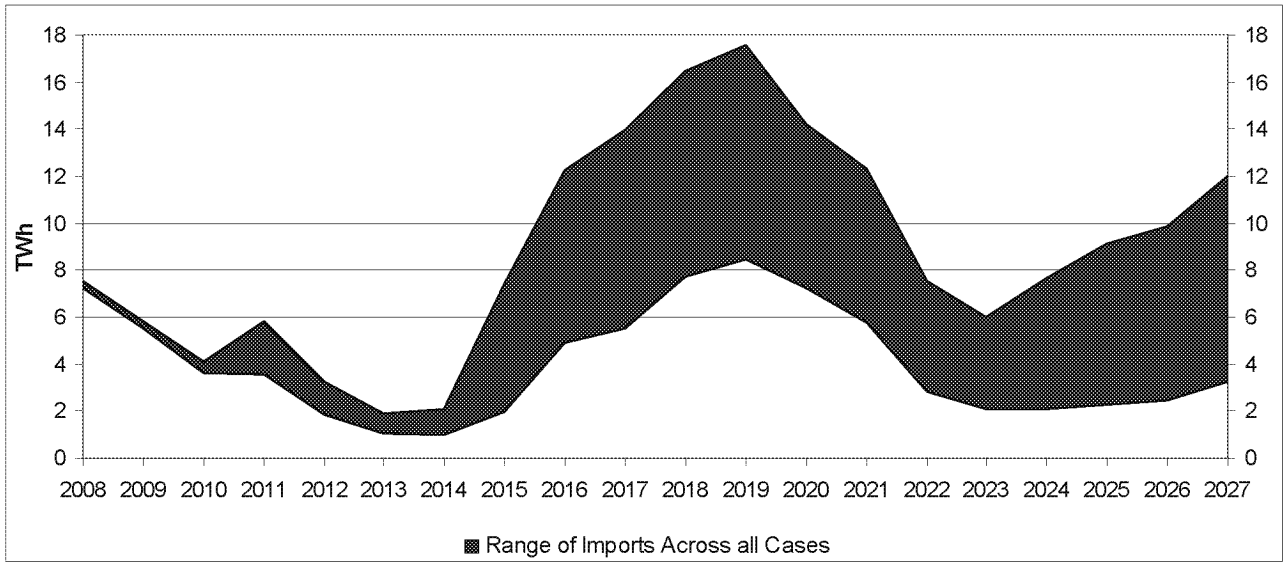
Source: OPA

Figure 19: Range of Coal-Fired Production across eight Scenarios (TWh)



Source: OPA

Figure 20: Range of Imports across eight Scenarios (TWh)



Source: OPA

Table 48: Annual Capacity Factor – Case 1A

Capacity Factors	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Coal	53%	51%	49%	50%	56%	51%	53%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Nuclear - Existing	83%	81%	81%	83%	85%	85%	83%	85%	83%	83%	83%	81%	81%	83%	83%	84%	84%	84%	84%	88%
Nuclear - New	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	80%	80%	81%	83%	84%	85%	86%	88%	89%	90%
Hydro	62%	62%	63%	61%	61%	62%	61%	61%	60%	60%	60%	60%	59%	59%	58%	59%	59%	59%	59%	59%
OPG LX	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Bio-Energy	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%
CCGT	20%	11%	9%	8%	8%	7%	7%	17%	21%	23%	25%	27%	20%	22%	17%	15%	14%	15%	17%	20%
Cogen	42%	44%	43%	43%	43%	41%	41%	41%	41%	41%	41%	41%	41%	41%	41%	41%	41%	41%	41%	41%
SCGT	0%	0%	0%	1%	1%	0%	0%	2%	4%	5%	5%	6%	5%	5%	2%	1%	1%	2%	2%	4%
Conservation	40%	39%	39%	43%	45%	46%	47%	48%	49%	49%	50%	50%	51%	51%	51%	51%	51%	51%	51%	51%
HQ_Inter	0%	8%	4%	5%	3%	4%	4%	4%	13%	13%	16%	16%	15%	15%	11%	11%	9%	9%	11%	11%
NUG	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%
NUG_Disp	0%	0%	0%	0%	0%	0%	0%	7%	15%	18%	20%	25%	18%	15%	9%	6%	7%	9%	11%	18%
Solar	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%
Wind	28%	28%	28%	28%	28%	28%	28%	27%	29%	28%	28%	28%	28%	28%	28%	28%	28%	28%	28%	28%

Source: OPA

Table 49: Annual Capacity Factor – Case 1B

Capacity Factors	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Coal	53%	51%	49%	50%	56%	51%	53%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Nuclear - Existing	83%	81%	81%	83%	85%	85%	83%	85%	83%	84%	84%	83%	83%	85%	85%	85%	86%	85%	86%	86%
Nuclear - New	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	80%	80%	81%	81%	83%	84%	86%	86%	89%	90%
Hydro	62%	62%	63%	61%	61%	62%	61%	61%	60%	60%	60%	60%	59%	59%	58%	59%	59%	59%	59%	59%
OPG LX	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	1%	1%	0%	0%	0%	0%	0%	0%	0%	0%
Bio-Energy	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%
CCGT	20%	11%	9%	8%	8%	7%	7%	16%	24%	27%	30%	33%	26%	27%	17%	15%	14%	15%	17%	20%
Cogen	42%	44%	43%	43%	43%	41%	41%	41%	41%	41%	41%	41%	41%	41%	41%	41%	41%	41%	41%	41%
SCGT	0%	0%	0%	1%	1%	0%	0%	2%	4%	7%	8%	9%	6%	5%	1%	1%	1%	1%	1%	3%
Conservation	40%	39%	39%	43%	45%	46%	47%	48%	49%	49%	50%	50%	51%	51%	51%	51%	51%	51%	51%	51%
HQ_Inter	0%	8%	4%	5%	3%	4%	4%	4%	14%	14%	19%	19%	17%	17%	10%	10%	9%	9%	10%	10%
NUG	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%
NUG_Disp	0%	0%	0%	0%	0%	0%	0%	9%	23%	28%	34%	38%	30%	25%	8%	6%	7%	9%	10%	17%
Solar	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%
Wind	28%	28%	28%	28%	28%	28%	28%	27%	29%	28%	28%	28%	28%	28%	28%	28%	28%	28%	28%	28%

Source: OPA

Table 50: Annual Capacity Factor – Case 2A

Capacity Factors	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Coal	53%	52%	50%	51%	58%	53%	55%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Nuclear - Existing	83%	81%	81%	83%	85%	85%	83%	85%	83%	83%	83%	81%	81%	83%	83%	84%	84%	84%	84%	88%
Nuclear - New	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	80%	80%	81%	83%	84%	85%	86%	88%	89%	90%
Hydro	62%	62%	63%	61%	61%	62%	61%	61%	60%	60%	60%	60%	59%	59%	58%	59%	59%	59%	59%	59%
OPG LX	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Bio-Energy	73%	73%	73%	73%	73%	73%	73%	73%	73%	73%	73%	73%	73%	73%	73%	73%	73%	73%	73%	73%
CCGT	21%	11%	10%	8%	10%	8%	9%	19%	21%	24%	27%	29%	22%	24%	20%	18%	18%	20%	23%	26%
Cogen	42%	44%	43%	43%	43%	41%	41%	41%	41%	41%	41%	41%	41%	41%	41%	41%	41%	41%	41%	41%
SCGT	0%	0%	0%	1%	1%	0%	0%	3%	3%	4%	4%	6%	5%	5%	3%	2%	4%	4%	5%	6%
Conservation	40%	39%	39%	43%	45%	46%	47%	48%	49%	49%	50%	50%	51%	51%	51%	51%	51%	51%	51%	51%
HQ_Inter	0%	8%	4%	5%	3%	4%	4%	4%	13%	13%	16%	16%	15%	15%	11%	11%	9%	9%	11%	11%
NUG	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%
NUG_Disp	0%	0%	0%	0%	0%	0%	1%	10%	11%	15%	18%	24%	18%	17%	12%	11%	14%	17%	23%	27%
Solar	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%
Wind	28%	28%	28%	28%	28%	28%	28%	28%	28%	28%	28%	28%	28%	28%	28%	28%	28%	28%	28%	28%

Source: OPA

Table 51: Annual Capacity Factor – Case 2B

Capacity Factors	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Coal	53%	52%	50%	51%	58%	53%	55%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Nuclear - Existing	83%	81%	81%	83%	85%	85%	83%	85%	83%	84%	84%	83%	83%	85%	85%	85%	86%	85%	86%	86%
Nuclear - New	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	80%	80%	81%	81%	83%	84%	86%	86%	89%	90%
Hydro	62%	62%	63%	61%	61%	62%	61%	61%	60%	60%	60%	60%	59%	59%	58%	59%	59%	59%	59%	59%
OPG LX	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	0%	0%	0%	0%	0%	0%	0%	0%
Bio-Energy	72%	72%	72%	72%	72%	72%	72%	72%	72%	72%	72%	72%	72%	72%	72%	72%	72%	72%	72%	72%
CCGT	21%	11%	10%	8%	10%	8%	9%	18%	27%	31%	35%	38%	30%	31%	22%	20%	20%	22%	24%	28%
Cogen	42%	44%	43%	43%	43%	41%	41%	41%	41%	41%	41%	41%	41%	41%	41%	41%	41%	41%	41%	41%
SCGT	0%	0%	0%	1%	1%	0%	0%	3%	5%	7%	8%	10%	8%	7%	3%	3%	4%	5%	7%	9%
Conservation	40%	39%	39%	43%	45%	46%	47%	48%	49%	49%	50%	50%	51%	51%	51%	51%	51%	51%	51%	51%
HQ_Inter	0%	8%	4%	5%	3%	4%	4%	4%	14%	14%	19%	19%	17%	17%	10%	10%	9%	9%	10%	10%
NUG	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%
NUG_Disp	0%	0%	0%	0%	0%	0%	1%	12%	29%	35%	41%	44%	38%	39%	21%	20%	21%	24%	30%	36%
Solar	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%
Wind	28%	28%	28%	28%	28%	28%	28%	28%	28%	28%	28%	28%	28%	28%	28%	28%	28%	28%	28%	28%

Source: OPA

Table 52: Annual Capacity Factor – Case 3A

Capacity Factors	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Coal	53%	51%	49%	49%	51%	47%	48%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Nuclear - Existing	83%	81%	81%	83%	85%	85%	83%	85%	83%	83%	83%	81%	81%	83%	83%	84%	84%	84%	84%	88%
Nuclear - New	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Hydro	62%	62%	63%	61%	61%	62%	61%	61%	60%	60%	60%	60%	59%	59%	58%	59%	59%	59%	59%	59%
OPG LX	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Bio-Energy	79%	78%	78%	78%	69%	64%	64%	77%	77%	76%	78%	79%	79%	79%	76%	72%	74%	73%	75%	77%
CCGT	20%	11%	9%	6%	6%	5%	5%	15%	18%	20%	22%	25%	21%	23%	17%	14%	13%	14%	17%	20%
Cogen	42%	44%	43%	43%	43%	41%	41%	41%	41%	41%	41%	41%	41%	41%	41%	41%	41%	41%	41%	41%
SCGT	0%	0%	0%	0%	0%	0%	0%	2%	2%	3%	4%	6%	4%	4%	1%	1%	1%	1%	1%	2%
Conservation	40%	39%	38%	42%	42%	42%	43%	44%	45%	45%	46%	46%	47%	47%	47%	47%	47%	47%	47%	47%
HQ_Inter	0%	8%	4%	5%	3%	4%	4%	4%	13%	13%	16%	16%	15%	15%	11%	11%	9%	9%	11%	11%
NUG	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%
NUG_Disp	0%	0%	0%	0%	0%	0%	0%	3%	5%	6%	8%	11%	9%	8%	4%	2%	3%	4%	4%	8%
Solar	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%
Wind	28%	28%	28%	28%	28%	28%	28%	28%	28%	28%	28%	28%	28%	28%	28%	28%	28%	28%	28%	28%

Source: OPA

Table 53: Annual Capacity Factor – Case 3B

Capacity Factors	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Coal	53%	51%	49%	49%	51%	47%	48%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Nuclear - Existing	83%	81%	81%	83%	85%	85%	83%	85%	83%	84%	84%	83%	83%	85%	85%	85%	86%	85%	86%	86%
Nuclear - New	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	80%	80%	81%	83%	84%	85%	86%	88%	89%	90%
Hydro	62%	62%	63%	61%	61%	62%	61%	61%	60%	60%	60%	60%	59%	59%	58%	59%	59%	59%	59%	59%
OPG LX	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Bio-Energy	79%	78%	78%	78%	69%	64%	64%	75%	80%	80%	80%	80%	80%	80%	77%	74%	75%	75%	76%	78%
CCGT	20%	11%	9%	6%	6%	5%	5%	14%	22%	24%	27%	29%	26%	29%	18%	15%	14%	15%	18%	20%
Cogen	42%	44%	43%	43%	43%	41%	41%	41%	41%	41%	41%	41%	41%	41%	41%	41%	41%	41%	41%	41%
SCGT	0%	0%	0%	0%	0%	0%	0%	0%	3%	5%	6%	7%	6%	6%	2%	1%	1%	2%	2%	3%
Conservation	40%	39%	38%	42%	42%	42%	43%	44%	45%	45%	46%	46%	47%	47%	47%	47%	47%	47%	47%	47%
HQ_Inter	0%	8%	4%	5%	3%	4%	4%	4%	13%	13%	16%	16%	15%	15%	11%	11%	9%	9%	11%	11%
NUG	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%
NUG_Disp	0%	0%	0%	0%	0%	0%	0%	3%	9%	11%	13%	16%	14%	14%	5%	4%	4%	5%	5%	9%
Solar	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%
Wind	28%	28%	28%	28%	28%	28%	28%	28%	28%	28%	28%	28%	28%	28%	28%	28%	28%	28%	28%	28%

Source: OPA

Table 54: Annual Capacity Factor – Case 4A

Capacity Factors	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Coal	53%	51%	49%	50%	56%	52%	53%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Nuclear - Existing	83%	81%	81%	83%	85%	85%	83%	85%	83%	83%	83%	81%	81%	83%	83%	84%	84%	84%	84%	88%
Nuclear - New	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	80%	80%	81%	83%	84%	85%	86%	88%	89%	90%
Hydro	51%	51%	53%	52%	52%	52%	51%	51%	51%	51%	51%	52%	53%	53%	53%	53%	53%	53%	53%	54%
OPG LX	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Bio-Energy	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%
CCGT	20%	11%	9%	8%	8%	7%	7%	17%	21%	22%	24%	26%	20%	22%	18%	16%	15%	16%	18%	21%
Cogen	42%	44%	43%	43%	43%	41%	41%	41%	41%	41%	41%	41%	41%	41%	41%	41%	41%	41%	41%	41%
SCGT	0%	0%	0%	1%	1%	0%	0%	2%	4%	4%	4%	5%	5%	5%	2%	2%	2%	3%	3%	6%
Conservation	40%	39%	39%	43%	45%	46%	47%	48%	49%	49%	50%	50%	51%	51%	51%	51%	51%	51%	51%	51%
HQ_Inter	0%	8%	4%	5%	3%	4%	4%	4%	13%	13%	16%	16%	15%	15%	11%	11%	9%	9%	11%	11%
NUG	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%
NUG_Disp	0%	0%	0%	0%	0%	0%	0%	7%	15%	16%	18%	22%	19%	15%	10%	8%	10%	12%	14%	21%
Solar	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%
Wind	28%	28%	28%	28%	28%	28%	28%	28%	28%	27%	28%	28%	28%	27%	28%	28%	28%	28%	28%	28%

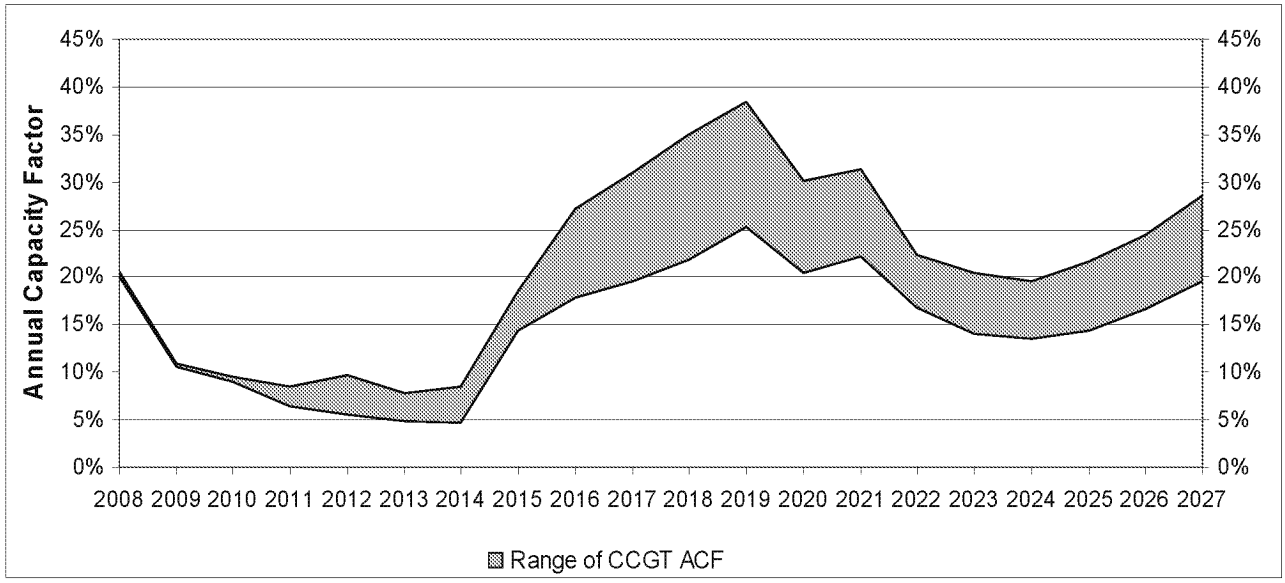
Source: OPA

Table 55: Annual Capacity Factor – Case 4B

Capacity Factors	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Coal	53%	51%	49%	50%	56%	52%	53%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Nuclear - Existing	83%	81%	81%	83%	85%	85%	83%	85%	83%	84%	84%	83%	83%	85%	85%	85%	86%	85%	86%	86%
Nuclear - New	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	80%	80%	81%	81%	83%	84%	86%	86%	89%	90%
Hydro	51%	51%	53%	52%	52%	52%	51%	51%	51%	51%	51%	52%	53%	53%	53%	53%	53%	53%	53%	54%
OPG LX	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	1%	1%	0%	0%	0%	0%	0%	0%	0%
Bio-Energy	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%
CCGT	20%	11%	9%	8%	8%	7%	7%	16%	24%	26%	29%	32%	27%	27%	18%	15%	14%	16%	18%	20%
Cogen	42%	44%	43%	43%	43%	41%	41%	41%	41%	41%	41%	41%	41%	41%	41%	41%	41%	41%	41%	41%
SCGT	0%	0%	0%	1%	1%	0%	0%	2%	4%	6%	7%	8%	6%	5%	2%	1%	2%	2%	2%	4%
Conservation	40%	39%	39%	43%	45%	46%	47%	48%	49%	49%	50%	50%	51%	51%	51%	51%	51%	51%	51%	51%
HQ_Inter	0%	8%	4%	5%	3%	4%	4%	4%	14%	14%	19%	19%	17%	17%	10%	10%	9%	9%	10%	10%
NUG	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%
NUG_Disp	0%	0%	0%	0%	0%	0%	0%	9%	23%	26%	32%	35%	30%	26%	10%	8%	9%	11%	12%	20%
Solar	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%
Wind	28%	28%	28%	28%	28%	28%	28%	28%	28%	27%	28%	28%	28%	27%	28%	28%	28%	28%	28%	28%

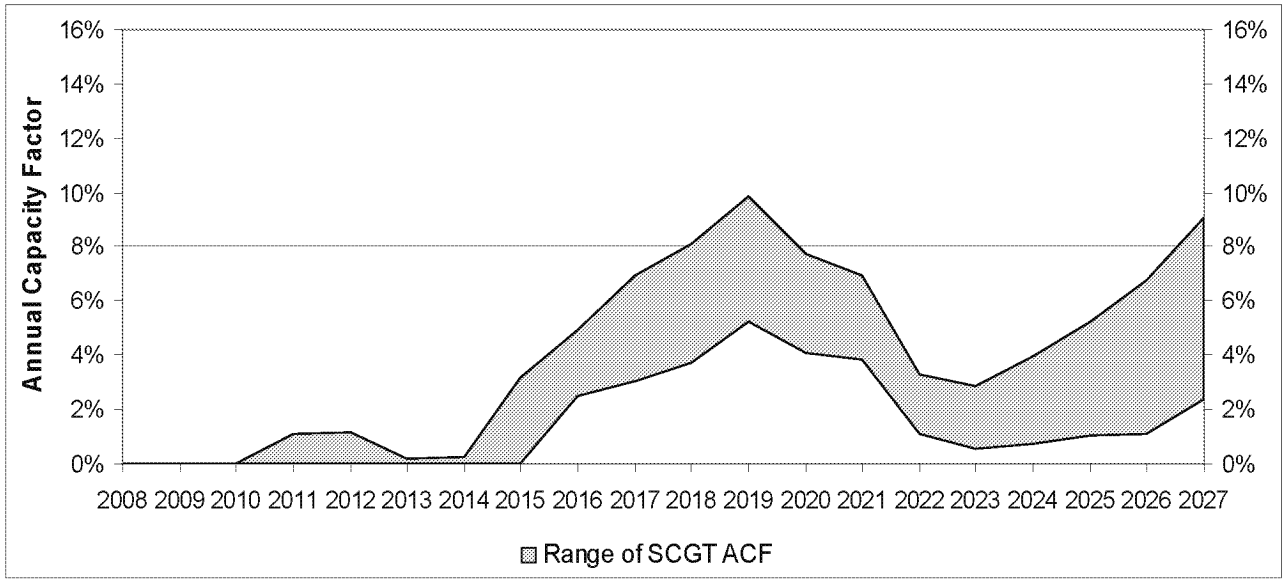
Source: OPA

Figure 21: Range of CCGT Capacity Factors across eight Scenarios



Source: OPA

Figure 22: Range of SCGT Capacity Factors across eight Scenarios



Source: OPA

Q. How do the cases relate to the Integrated Power System Plan?

The IPSP has been developed to address resource requirements across a variety of potential circumstances or conditions. The Plan was developed both according to a set

of assumed reference conditions (e.g., as related to load forecast, Conservation uptake, implementing transmission, etc.) as well as in recognition of uncertainties related to those assumed conditions. Illustrations of scenarios and possible adaptations have been discussed above, and have suggested a range of potential resource requirements as well as a variety of ways of meeting those requirements over the long term.

In addition to recognizing these broader uncertainties, the IPSP also recognizes risk around implementation of committed and planned resources as well as the ongoing performance of existing, committed and planned resources. As discussed in Exhibit D-2-1, Attachment 2, these kinds of risks are to be addressed in the near- to mid term by retaining all or part of Ontario's existing coal-fired resources in-service to the end of 2014. Beyond 2014, these additional risks are to be managed both through the development and maintenance of options and, as discussed in Exhibit D-2-1, Attachment 3, through additional levels of planning reserve as appropriate.

Q. What is the role of options in the Integrated Power System Plan?

A. Options are developed to provide adaptive capability. Without options, the ability to adapt in face of uncertainty, risk and opportunity could be compromised or at least be limited to responses which are feasible in short-order, though which may not be the most attractive over the long run. Certain options such as the development of additional natural gas-fired generation entail relatively short lead-times and may thus be attractive candidates in the short term. Options around natural gas-fired generation include development of new facilitates, expansion of existing facilities, and extending the service of existing facilities that would otherwise have been deregistered.

Other options require longer lead-times, such as laying the groundwork for potential out-of-province purchases, nuclear refurbishments, new-build nuclear, major transmission, additional hydroelectric potential, energy storage, and emerging end-use or generation technologies. It is the intent of the Plan to foster options and to provide for sufficient flexibility to permit the exercise of these options should they turn out to be feasible and attractive.

Q. How does system operability relate to plan robustness?

A. Meeting ongoing resource requirements includes ensuring power system operability. The Plan will need to retain the capability of providing for system operability across a range of possible conditions, particularly in recognition of uncertainties related to longer term load requirements and success in resource implementation and performance.

It is expected that ongoing requirements for system operability will be supported by flexible resources such as intermediate and peaking Conservation, peaking hydropower, and simple cycle and combined cycle turbine natural gas-fired generation, and the considerable interconnection capability with other jurisdictions. Options for additional flexibility may include additional levels of flexible Conservation and renewables, enhancing operating ranges of combined cycle and CHP resources, better forecasting of wind resources, wind generator output controls and storage technologies. Plan updates will reflect ongoing consideration of system operability requirements. Operating implications of the Plan will be regularly assessed.

Q. What are some key implications of the cases' results?

A. The cases demonstrate that the Plan is compliant with the Directive under a reasonable range of conditions associated with the key plan elements of forecast demand (Scenarios 2A and 2B), Conservation (Scenarios 3A and 3B), renewable supply (Scenarios 4A and 4B) and nuclear availability (Cases A and B for each scenario).

The cases illustrate that lower resource availability and performance will tend to increase the requirement for other types of resources as well as increase the utilization of fossil-fired resources and imports. This is particularly evident in the period 2015 to 2020, which has less nuclear. Plan robustness is demonstrated as resource requirements are met across all cases. It is not expected that any additional resources will have to be acquired by 2010 to meet these cases.

Managing risk over the course of the plan will be supported by the use of existing resources including interconnections, by developing appropriate levels of planning

reserve, and by the development and use of options. In the near- to mid term, planning reserve includes retaining coal-fired resources in service until the end of 2014. In the mid- to longer term, options include continuing to explore the potential for purchases from outside of the province, opportunities for greater uptake in Conservation and renewable potential, flexibility around nuclear restoration, redevelopment of existing arrangements with natural gas-fired facilities, expansions and/or conversion at existing sites, development of storage capability, and greater use of emerging technologies. All of the above will be facilitated by ongoing monitoring, evaluation, coordination and planning.

PLAN COST

1.0 INTRODUCTION

This exhibit presents the cost of the Integrated Power System Plan (the "IPSP" or the "Plan") from two perspectives: overall plan costs, and impact on customer costs. These terms are defined as follows:

- Overall Plan Cost - The overall cost of the Plan was determined using the same methodology presented in the Supply Mix Report. This analysis included the summing of cash flows of all the proposed Conservation spending and supply investments, and the cost of energy production from existing plants over the forecast period. These Plan costs, along with other economic benchmarks, were calculated for the two cases in the IPSP and are presented along with the results for Monte Carlo simulation analysis. Monte Carlo analysis simulates the behavior of complex systems by incorporating uncertainty into input assumptions, and providing a range of possible outcomes rather than the single point estimate provided by most spreadsheet based models; and
- Impact on Customer Cost - The potential impact of the Plan on customer cost is evaluated in the cost to customer analysis. This evaluation is used to estimate the impact of the Plan on an average customer's bill using the major cost components that are paid by customers: the electricity commodity, conservation, transmission, wholesale market charges, debt retirement charges, and distribution.

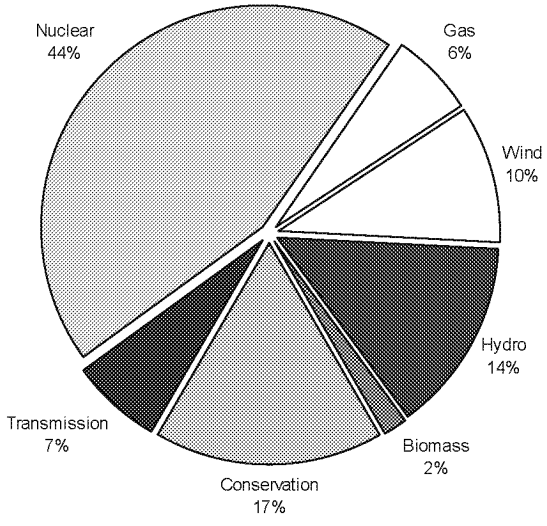
2.0 OVERALL PLAN COST

Q. What is the Plan cost?

A. The cost of Case 1A, which assumes that Pickering B is refurbished, is determined by summing the cash flows of Conservation, investment in new transmission assets plus all the planned additions to generation. To estimate the cost of the Plan, the same model that was used for the analysis in the Supply Mix Report, the Portfolio Screening Model ("PSM") was used. The PSM allows for simulation of the generation system over the twenty year Plan period, and provides cash flows in aggregate and year by year.

Expenditures for Conservation, new transmission assets and planned generation for Case 1A total $59.4 billion over the Plan period. The total spending on each of these three components, plus a breakdown of planned generation by major technology type is outlined in Figure 1.

Figure 1: Case 1A Aggregate Planned Generation, Transmission and Conservation Spending 2008-2027 (2007 $Billions)



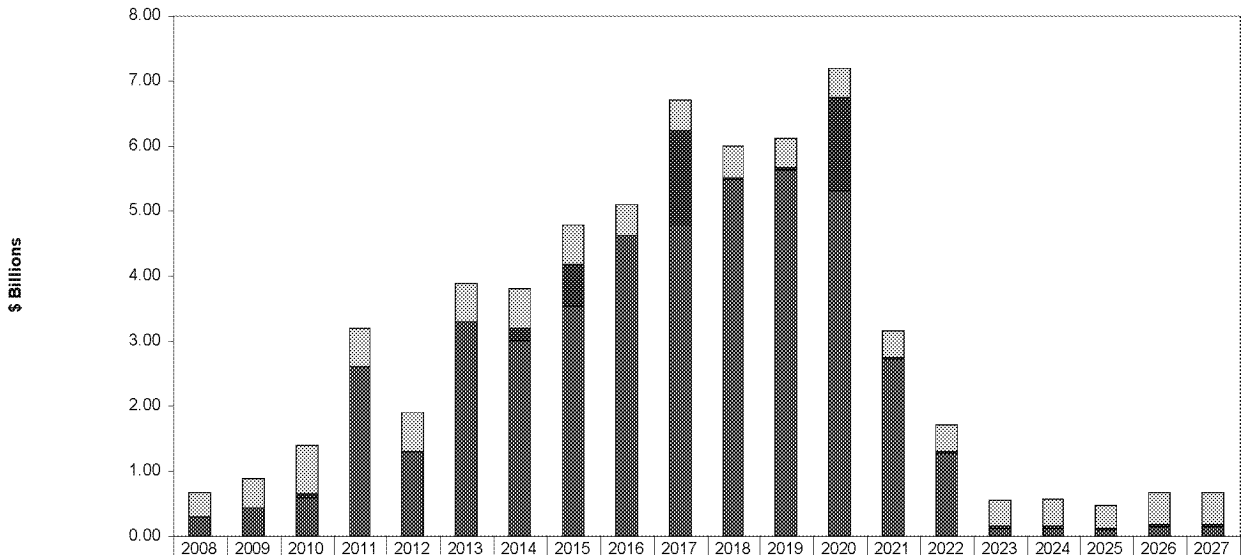
	2007 $ Billions
Conservation	9.9
Transmission	4.0
Nuclear	26.5
Gas	3.6
Wind	6.0
Hydro	8.4
Biomass	1.0
Total	59.4

Source: OPA

Q. What is the annual expenditure profile of the components of the Plan cost?

The annual profile for capital expenditures associated with planned generation assets, new transmission investments and Conservation initiatives for Case 1A is outlined in Figure 2.

Figure 2: Annual Capital Expenditures (Case 1A) (2007 $Billions)

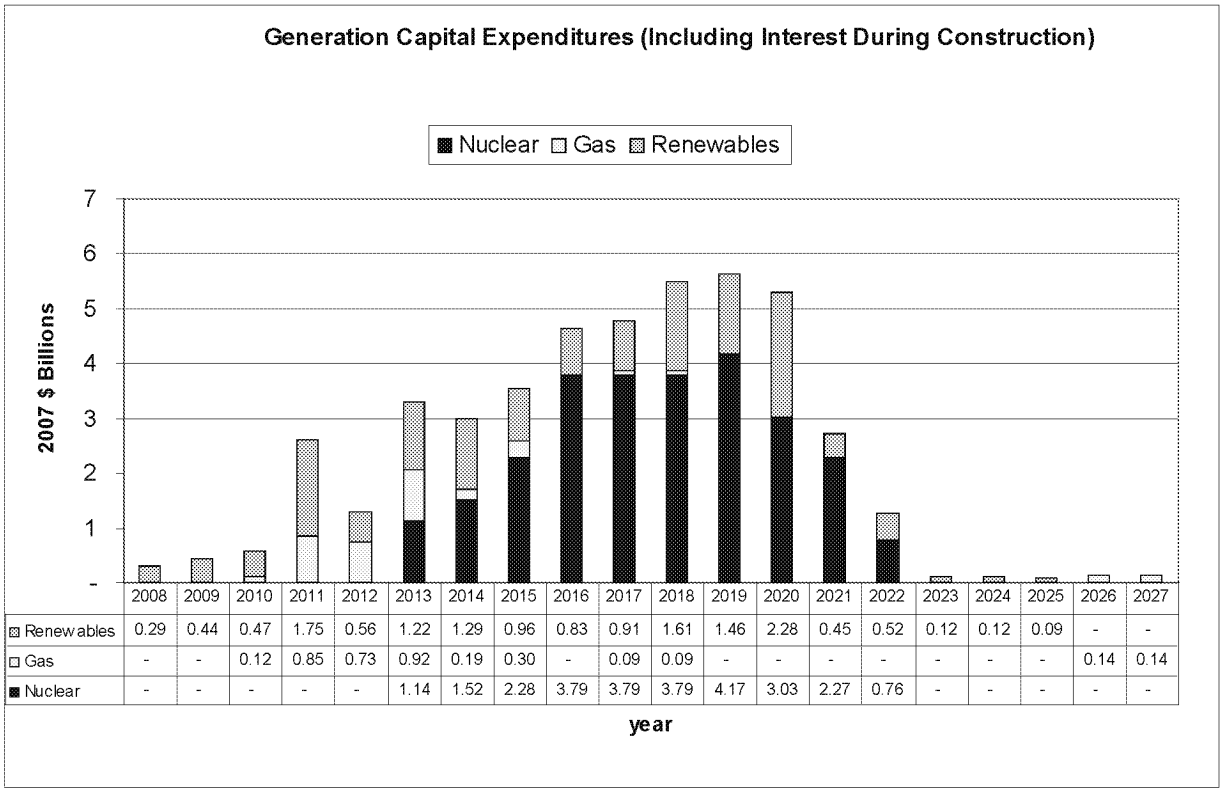


	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Conservation	0.37	0.45	0.75	0.59	0.60	0.60	0.62	0.62	0.48	0.47	0.48	0.46	0.44	0.40	0.40	0.39	0.41	0.35	0.51	0.50
Transm. Capital	0.00	0.00	0.07	0.00	0.00	0.00	0.19	0.63	0.00	1.44	0.03	0.03	1.44	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Gen. Capital	0.29	0.44	0.59	2.60	1.29	3.29	3.00	3.54	4.63	4.79	5.49	5.63	5.31	2.72	1.27	0.12	0.12	0.09	0.14	0.14

Source: OPA

The first major component of forecast capital expenditures is the supply investments, or capital expenditures expected for planned generation facilities. In 2007 dollars, a total of $45 billion in supply investments is anticipated over the twenty year Plan period, for Case 1A. This amount includes all planned generation facilities during the Plan period; however, it does not include committed capital for plants or refurbishments that have already signed Clean Energy Supply contracts with the OPA, but have yet to be connected to the grid. The costs of refurbishing Pickering B were assumed to be equivalent on a per KW basis to building new nuclear generation. The annual profile of these capital expenditures by technology for Case 1A is outlined in Figure 3.

Figure 3: Forecast Capital Expenditures on Planned Generation Facilities (Case 1A) (2007 $Billions)



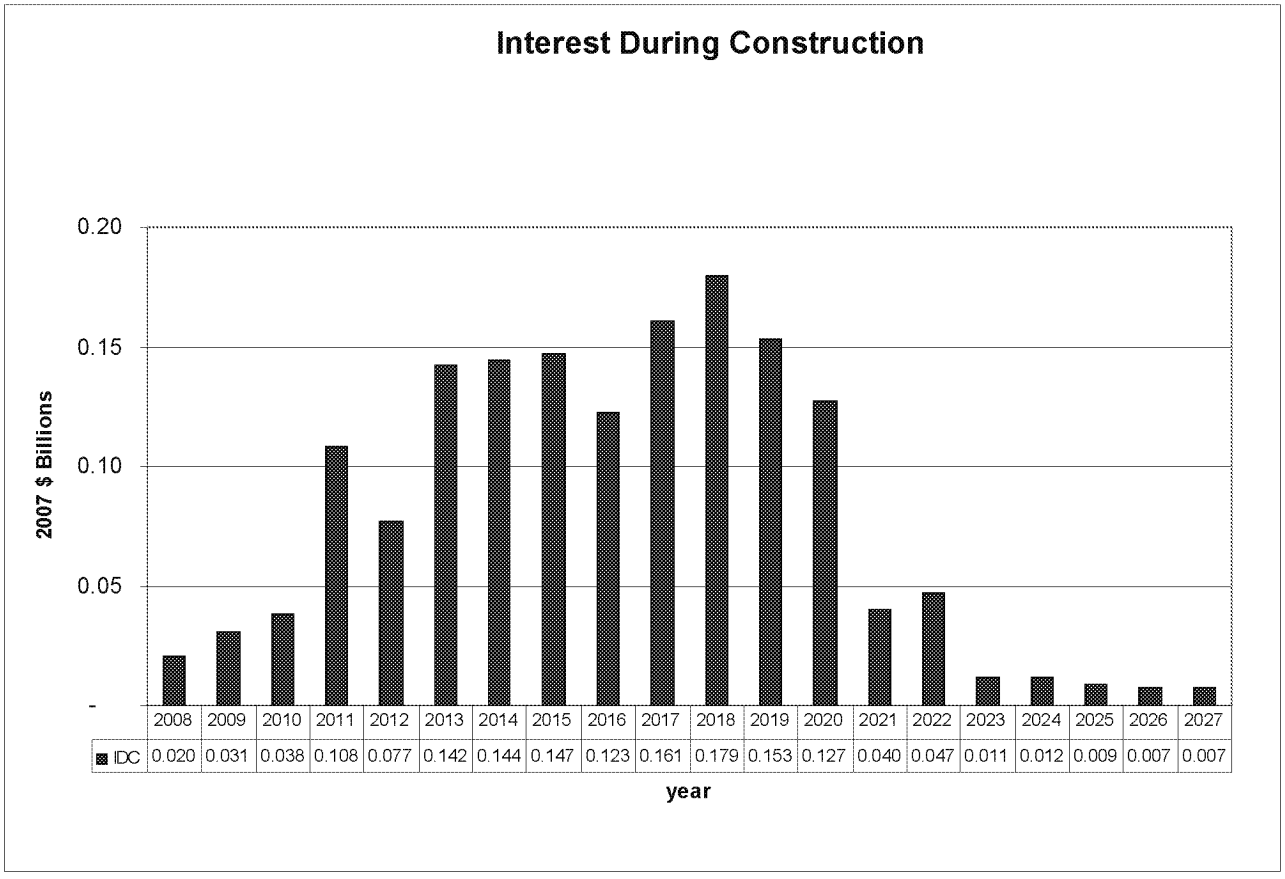
	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Renewables	0.29	0.44	0.47	1.75	0.56	1.22	1.29	0.96	0.83	0.91	1.61	1.46	2.28	0.45	0.52	0.12	0.12	0.09	-	-
Gas	-	-	0.12	0.85	0.73	0.92	0.19	0.30	-	0.09	0.09	-	-	-	-	-	-	-	0.14	0.14
Nuclear	-	-	-	-	-	1.14	1.52	2.28	3.79	3.79	3.79	4.17	3.03	2.27	0.76	-	-	-	-	-

Source: OPA

The above amounts for generation expenditures reflect "all-in" costs that include interest during construction. The assumptions for the capital cost (Figure 4 below) to build the various generation fuel types in the Plan represented overnight costs. Therefore, to more accurately reflect the "all-in" cost to build each type of generation, it was necessary to estimate what interest would accrue during construction. Assumptions associated with the length of time required to construct the facility range from one year for wind to six years for nuclear. The total interest that would accumulate over the construction period is calculated assuming equal capital expenditures and a 4% real interest rate.

The annual profile for interest during construction is outlined in Figure 4. Total interest accrued during construction over the twenty year Plan period is estimated to be $1.6 billion for Case 1A.

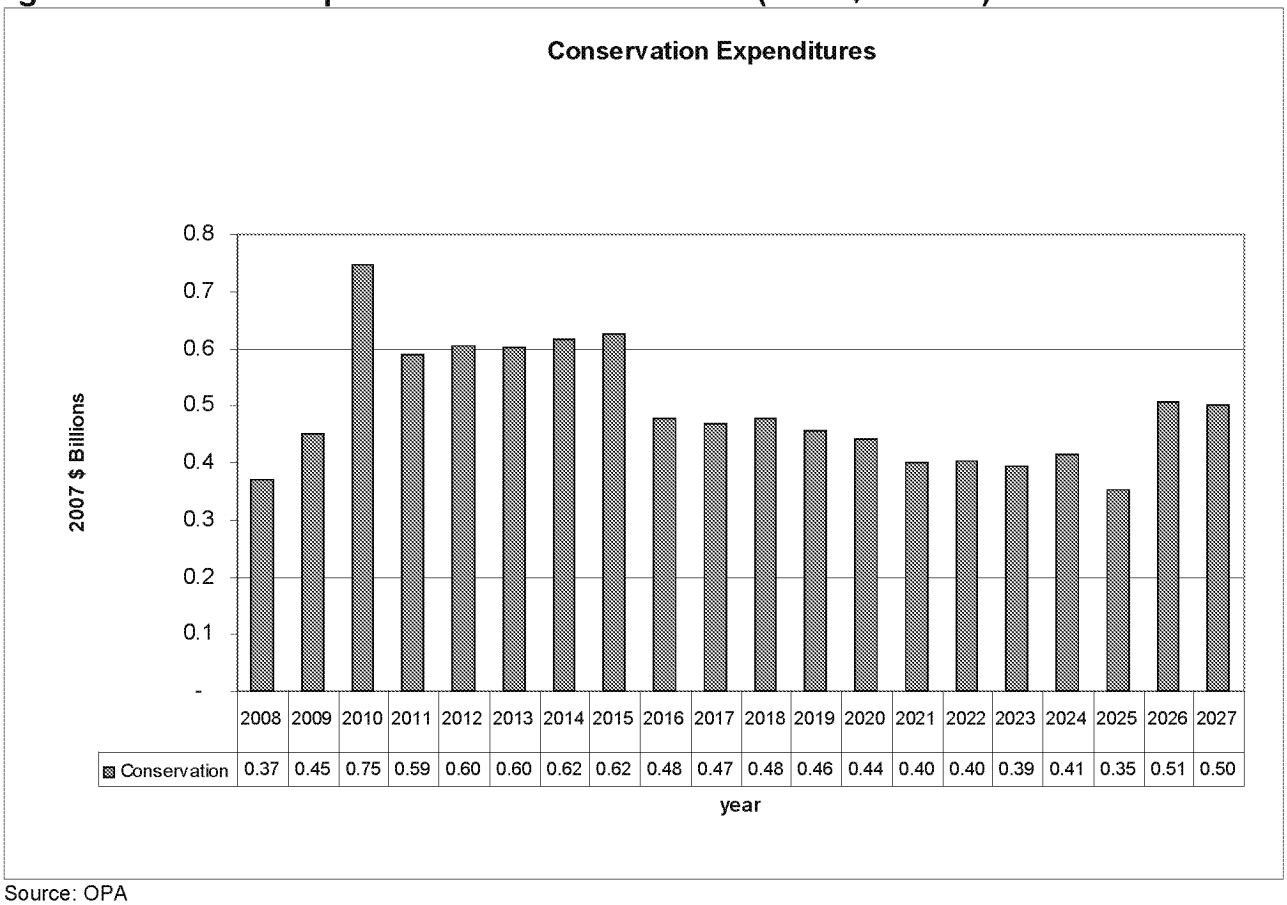
Figure 4: Interest During Construction for Planned Generation Facilities (Case 1A) (2007 $Billions)



Source: OPA

In addition to the above-noted supply investments, there are also cash flows related to Conservation expenditures over the Plan period. These Conservation expenditures toward incremental equipment and program costs total $10 billion over the Plan period and their annual profile is outlined in Figure 5.

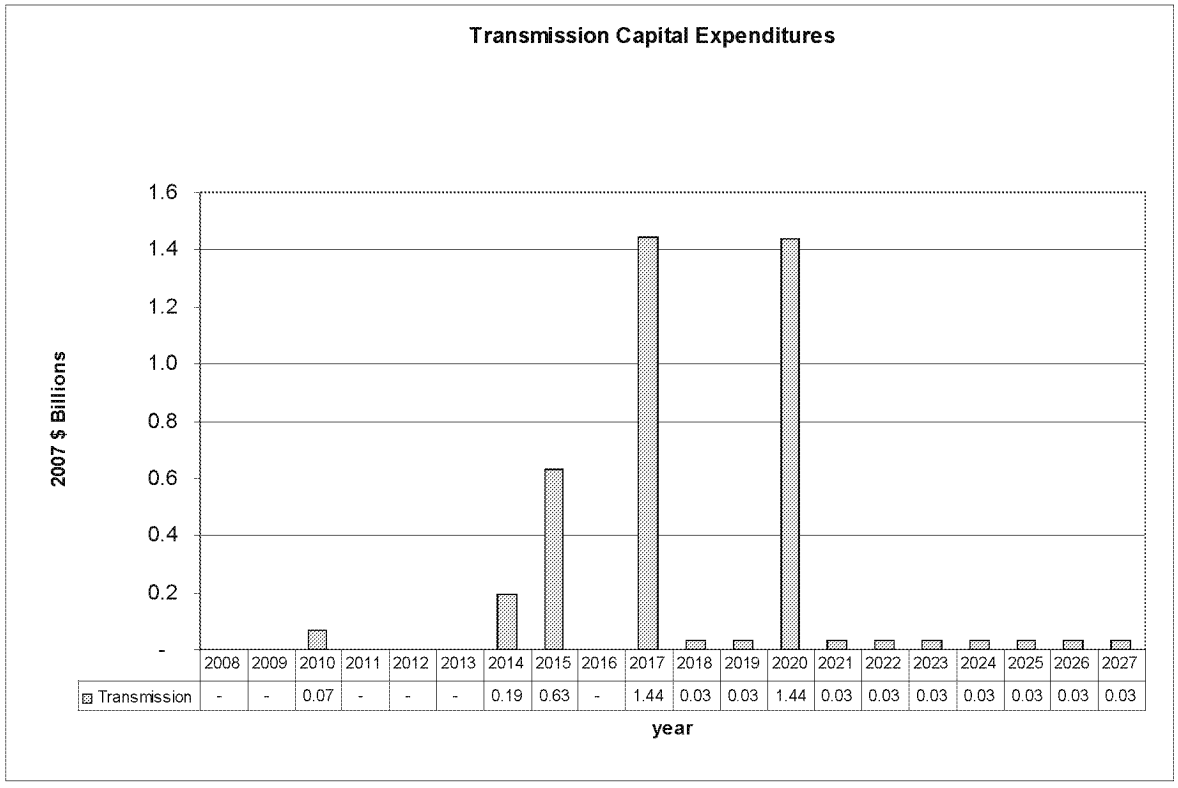
Figure 5: Forecast Expenditures on Conservation (2007 $Billions)



Source: OPA

The final major component of capital expenditure is related to new transmission investments. These transmission cash flows total $4 billion over the Plan period and their annual profile is outlined in Figure 6.

Figure 6: Forecast Expenditures on New Transmission Investments (2007 $Billions)



Source: OPA

Q. What assumptions were used to develop the Plan cost?

A. The assumptions used to derive these costs are set out in Table 1 which shows the capital and operating cost assumptions of planned generation.

Table 1: Cost Assumptions for Planned Generation

GENERATION TYPE	Capital Cost $/kw	Construction Period (years)	Fixed O&M $/kw	Variable O&M $/MWh	Heat Rate	Operating Life
CCGT	924	3	17.0	2.7	7,000	20
SCGT	665	2	16.0	3.5	9,500	20
Biogas	2,096	2	231.0	27.0	10,000	20
Cogen	1,413	3	22.0	2.7	6,300	20
Hydro RR	3,570	4	41.8	0.0		50
Hydro DIS	2,550	4	41.8	0.0		50
Nuclear	2,907	6	108.1	3.1	10,500	40
Wind	1,938	1	47.9	0.0		20
NUG replacing CCGT	924	3	17.0	2.7	7,000	10
Fuel Cell	5,447	3	8.3	54.1	7,930	20
Solar	5,712	2	13.3	0.0	10,280	20

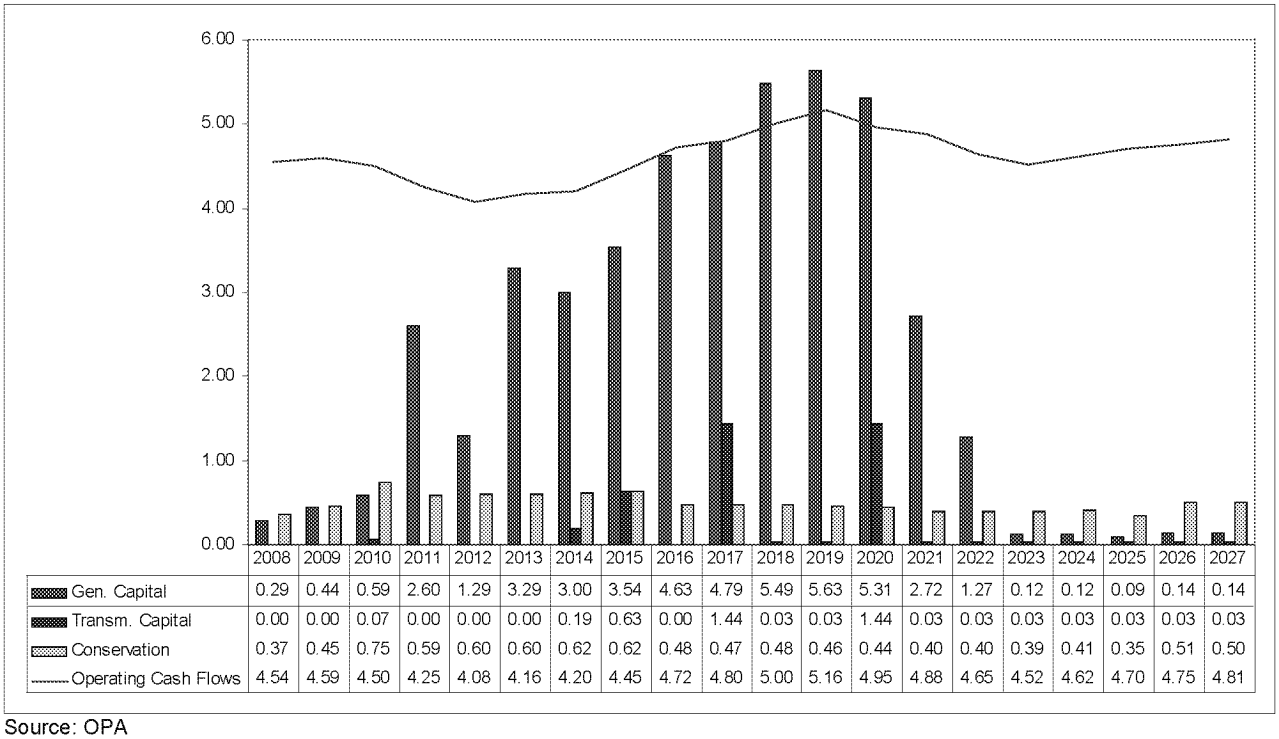
Nuclear Refurbishment Cost $M per unit	1,514

Source: OPA

Q. What are the operating costs associated with the Plan?

A. The cash flows associated with operating the existing and planned generation over the Plan period are also calculated. The annual profile of these operating expenses as well as a summary of the expenditures associated with Conservation, transmission and planned generation assets is outlined in Figure 7

Figure 7: Case 1A Forecast Period Annual Cash Flows (2007 $Billions)



	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Gen. Capital	0.29	0.44	0.59	2.60	1.29	3.29	3.00	3.54	4.63	4.79	5.49	5.63	5.31	2.72	1.27	0.12	0.12	0.09	0.14	0.14
Transm. Capital	0.00	0.00	0.07	0.00	0.00	0.00	0.19	0.63	0.00	1.44	0.03	0.03	1.44	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Conservation	0.37	0.45	0.75	0.59	0.60	0.60	0.62	0.62	0.48	0.47	0.48	0.46	0.44	0.40	0.40	0.39	0.41	0.35	0.51	0.50
Operating Cash Flows	4.54	4.59	4.50	4.25	4.08	4.16	4.20	4.45	4.72	4.80	5.00	5.16	4.95	4.88	4.65	4.52	4.62	4.70	4.75	4.81

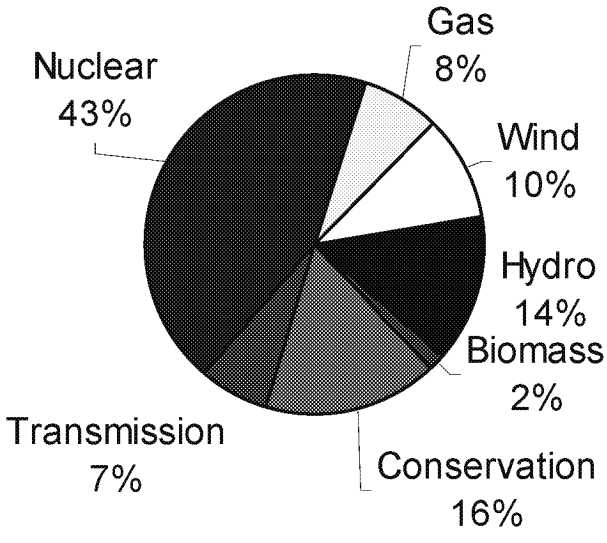
Source: OPA

Q. What other cases were considered in the Plan?

A second case was also developed, referred to as Case 1B, where the refurbishment of Pickering B does not occur and is instead replaced with gas-fired capacity in the interim, until new nuclear capacity comes on-line in 2020. In 2007 dollars, a total of $46 billion in supply investments is anticipated over the 20 year Plan period in this alternative case. Expenditures for Conservation, new transmission assets and planned generation total

$60.2 billion over the Plan period. The total spending on each of these three components, plus a breakdown of planned generation by major technology type is outlined in Figure 8.

Figure 8: Case 1B Aggregate Planned Generation, Transmission and Conservation Spending in 2008 - 2027 (2007 $Billions)

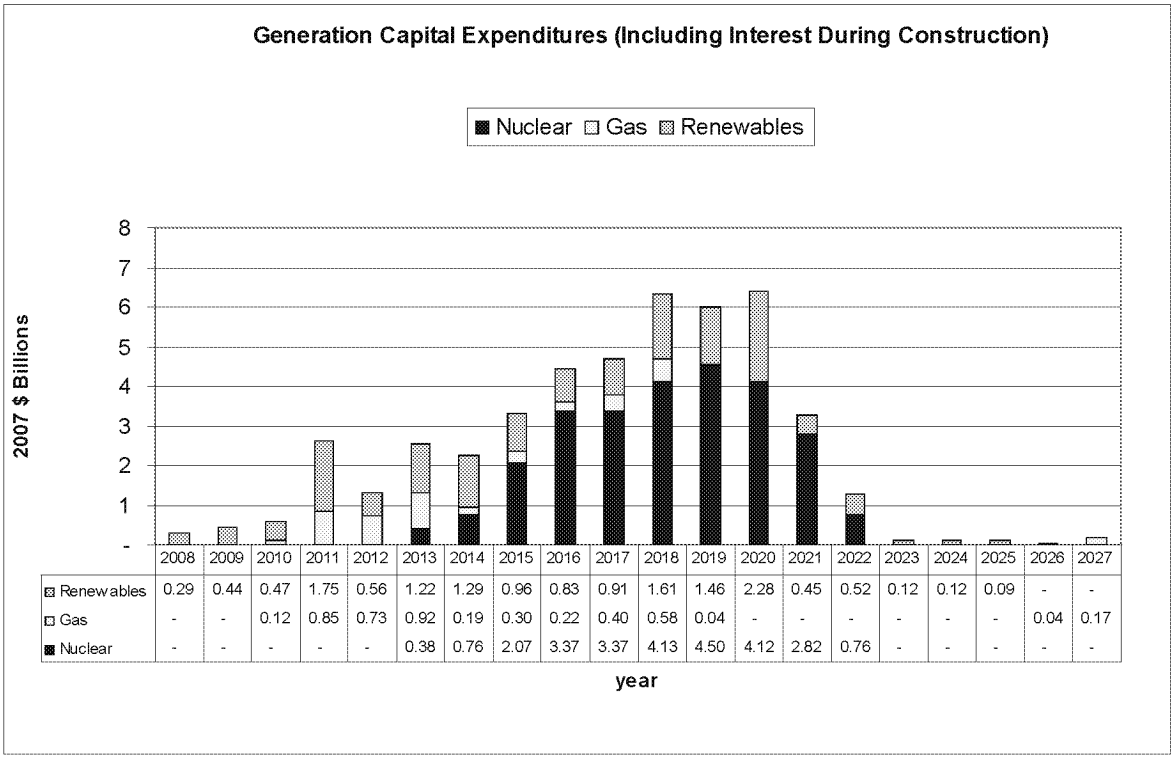


	2007 $ Billions
Conservation	9.9
Transmission	4.0
Nuclear	26.3
Gas	4.6
Wind	6.0
Hydro	8.4
Biomass	1.0
Total	60.2

Source: OPA

The investments in Conservation and transmission are the same for both Cases 1A and 1B. While the total cash expenditure for supply investments is similar, the timing and weighting between generation technologies does differ. The annual profile of these expenditures is illustrated in Figure 9.

Figure 9: Forecast Capital Expenditures on Planned Generation Facilities (Case 1B) (2007 $Billions)

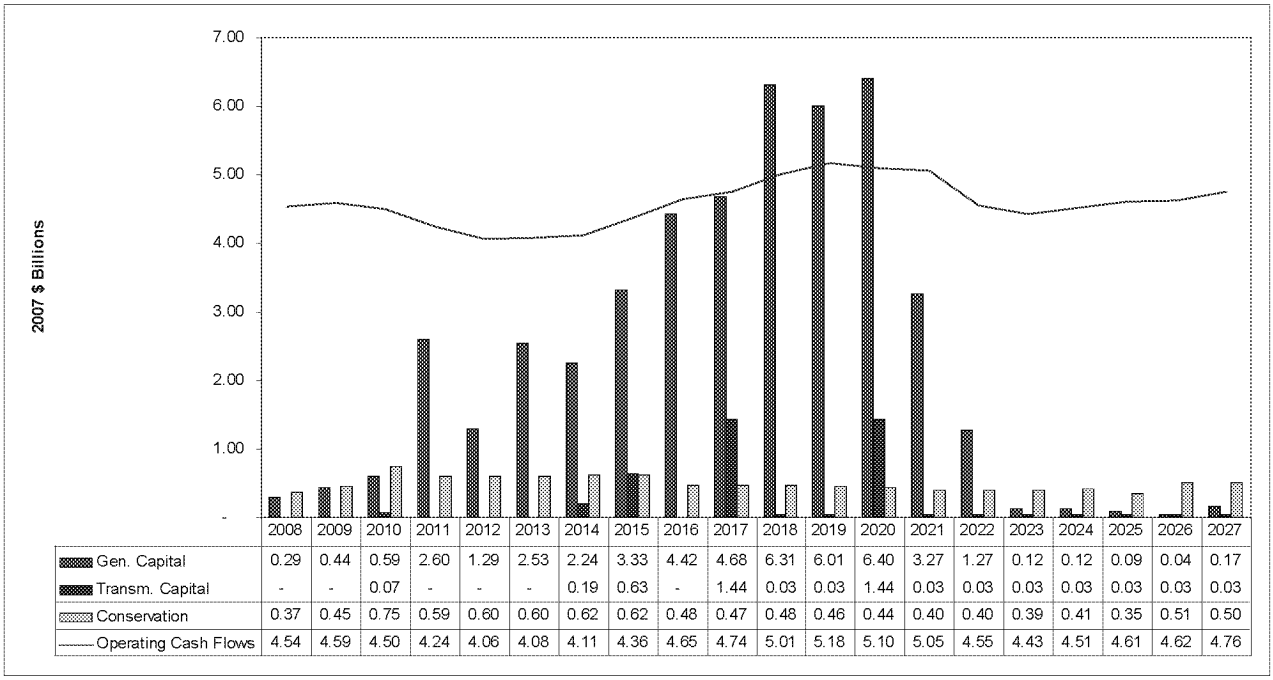


	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Renewables	0.29	0.44	0.47	1.75	0.56	1.22	1.29	0.96	0.83	0.91	1.61	1.46	2.28	0.45	0.52	0.12	0.12	0.09	-	-
Gas	-	-	0.12	0.85	0.73	0.92	0.19	0.30	0.22	0.40	0.58	0.04	-	-	-	-	-	-	0.04	0.17
Nuclear	-	-	-	-	-	0.38	0.76	2.07	3.37	3.37	4.13	4.50	4.12	2.82	0.76	-	-	-	-	-

Source: OPA

The annual cash flows associated with operating the existing and planned generation over the Plan period for Case 1B, as well as a summary of the expenditures associated with Conservation, transmission and planned generation assets is illustrated in Figure 10.

Figure 10: Case 1B Annual Cash Flows over Forecast Period (2007 $Billions)



	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Gen. Capital	0.29	0.44	0.59	2.60	1.29	2.53	2.24	3.33	4.42	4.68	6.31	6.01	6.40	3.27	1.27	0.12	0.12	0.09	0.04	0.17
Transm. Capital	-	-	0.07	-	-	-	0.19	0.63	-	1.44	0.03	0.03	1.44	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Conservation	0.37	0.45	0.75	0.59	0.60	0.60	0.62	0.62	0.48	0.47	0.48	0.46	0.44	0.40	0.40	0.39	0.41	0.35	0.51	0.50
Operating Cash Flows	4.54	4.59	4.50	4.24	4.06	4.08	4.11	4.36	4.65	4.74	5.01	5.18	5.10	5.05	4.55	4.43	4.51	4.61	4.62	4.76

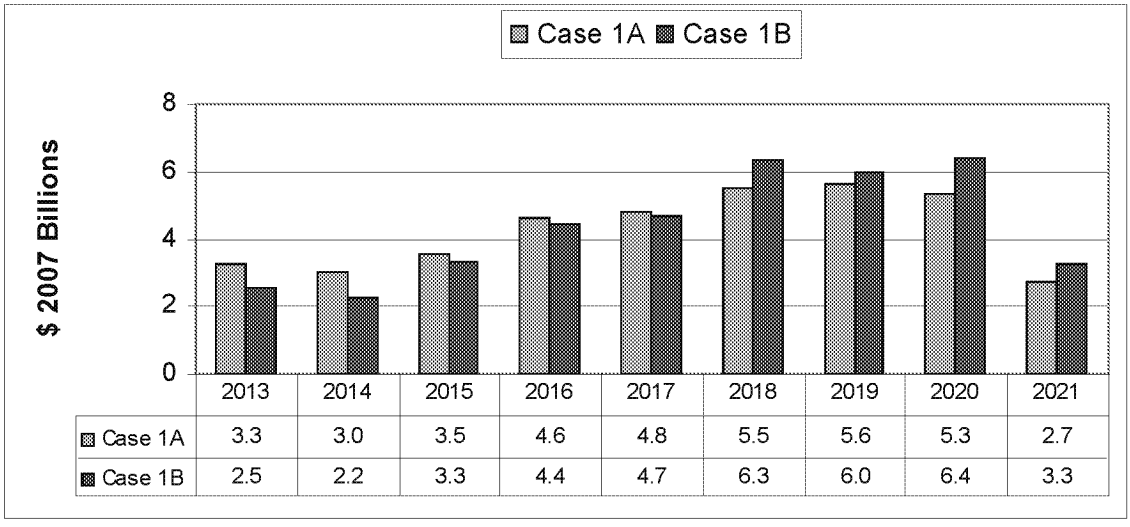
Source: OPA

Q. How do the costs of Case 1A and Case 1B compare?

A year-by-year comparison of the two cases is presented below covering the period 2013 through 2021 during which the cases diverge in composition of assets.

Comparisons of capital expenditures and operating cash flows for the two cases are illustrated in Figure 11 and Figure 12.

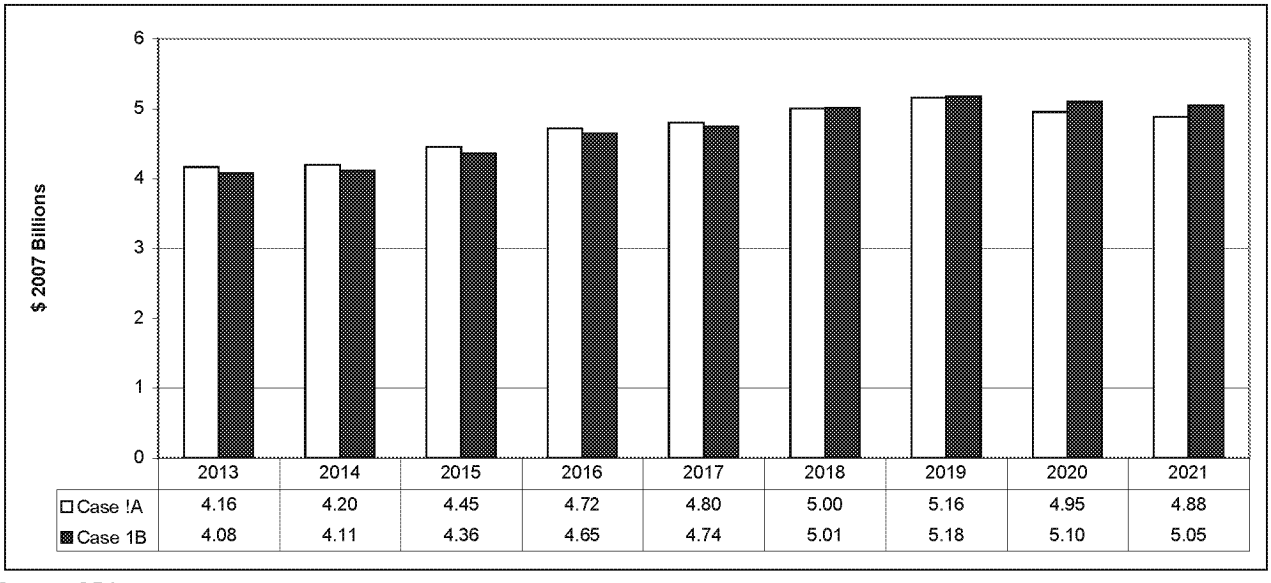
Figure 11: Comparison of Capital Expenditures for Planned Generation Assets (2007 $Billions)



	2013	2014	2015	2016	2017	2018	2019	2020	2021
Case 1A	3.3	3.0	3.5	4.6	4.8	5.5	5.6	5.3	2.7
Case 1B	2.5	2.2	3.3	4.4	4.7	6.3	6.0	6.4	3.3

Source: OPA

Figure 12: Comparison of Operating Cash Flows (2007 $Billions)



	2013	2014	2015	2016	2017	2018	2019	2020	2021
Case !A	4.16	4.20	4.45	4.72	4.80	5.00	5.16	4.95	4.88
Case 1B	4.08	4.11	4.36	4.65	4.74	5.01	5.18	5.10	5.05

Source: OPA

While the long-run results for Case 1A and Case 1B are similar, it is in the mechanics of how these results are achieved that the cases are distinguished. Case 1B contains fewer nuclear resources throughout the mid-term (reflecting the non-refurbishment of Pickering B), but relies more on other types of resources during the same period. For illustrative purposes, these other types of resources are depicted as natural gas-fired

resources, as well as unspecified resources. Case 1B has greater requirements for natural gas-fired and unspecified resources in the mid-term, but possesses greater flexibility for resource reductions over the longer term.

Case 1B has lower capital in the near term due to the delayed introduction of nuclear; however as more gas-fired generation is built and the new nuclear build commences, the capital expenditures for Case 1B eventually exceed that of Case 1A. The operating cash flows are similar for both cases as the higher fixed operating costs for the Pickering B refurbishment in Case 1A is offset by the higher variable costs associated with operating the gas-fired assets in Case 1B.

Q. How are cost uncertainties considered?

A. If all of the cash flows associated with Conservation, planned generation assets, transmission investments, and operating costs for existing and planned generation supply are discounted back at the real social discount rate of 4%, the total present value of the Ontario electricity system under Case 1A and Case 1B, including an additional amount representing terminal value (infinite replacement), is approximately $140.5 and $141 billion, respectively. However, the PSM also allows for Monte Carlo simulation of the generation system over the 20 year Plan period. By establishing uncertainty ranges around key input assumptions, the model determines the probability distribution associated with key outputs from the model in aggregate (present value). A more detailed description of the PSM's Monte Carlo capability and variable distribution assumptions can be found in Volume 4 section 1 of the Supply Mix Report.

The input variables that were subject to the Monte Carlo simulation analysis are identified in Table 2.

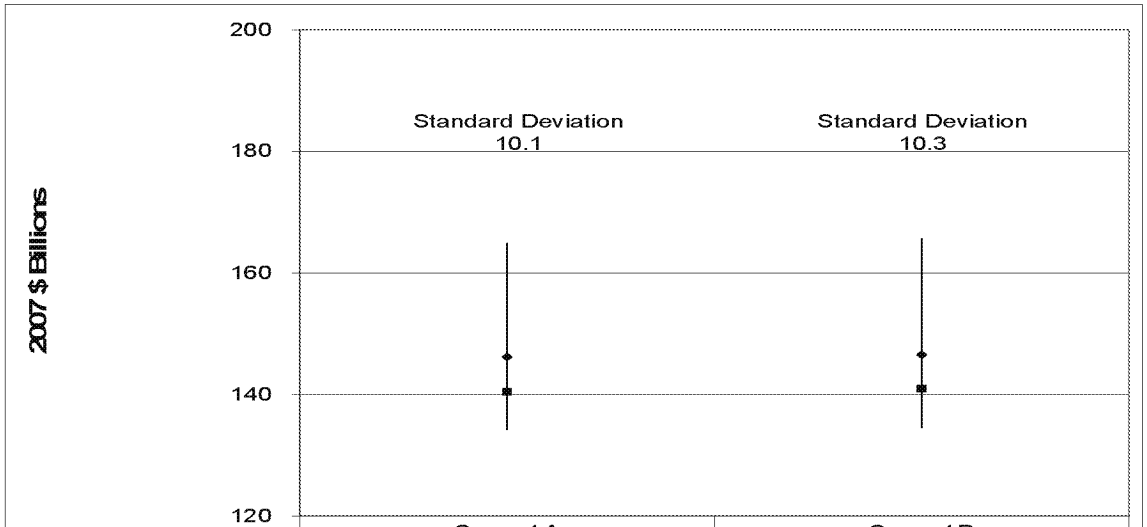
Table 2: Monte Carlo Simulation Variables

Assumption Type	Input Variables Subject to Monte Carlo Simulation
Fuel Cost	Price of natural gas, coal, oil and nuclear fuel
Capital Cost	Cost of GFG, nuclear, hydro and wind
Plant Performance	Forced outage rates associated with GFG, nuclear, coal, hydro and wind
Energy Demand	Ontario load

Source: OPA

The uncertainty or potential range of outcomes (mean, 95th percentile, 5th percentile and standard deviation) for the present value of total cash flows for Case1A and Case 1B, based on 250 iterations, is displayed in Figure 13.

Figure 13: Range of Present Value of Forecast Cash Flows – Case 1A vs. Case 1B (2007 $Billions)



	Case 1A	Case 1B
95th Percentile	164.8	165.5
5th Percentile	134.3	134.6
◆ Mean	146.2	146.5
■ Deterministic	140.5	141.0

Source: OPA

Given that the distributions for the key input assumptions are either lognormal (commodity prices) or triangular with skew to the high side (capital costs), the skewed nature of the results can be expected. The mean of the distribution for Case 1A is

$146.2 billion compared to the deterministic result of $140.5 billion, whereas the mean of the distribution for Case 1B is $146.5 billion compared to the deterministic result of $141 billion. Note also that for both cases, the difference between the 95th percentile result and the mean is greater than the difference between the 5th percentile and the mean.

The deterministic result and mean for Case 1A are slightly lower than for Case 1B, and Case 1A assumes that refurbishment costs for Pickering B are equal to the cost of the new build in Case 1B. The standard deviation is slightly higher for Case 1B, reflecting the increased risk associated with greater exposure to natural gas prices.

The results for both cases are close enough to indicate that there are various options around refurbishment or retirement of Pickering B when compared to new nuclear. The level of detail in the analysis presented here is not sufficient or appropriate as a basis for a decision for or against either alternative. This comparison of alternatives will be more relevant and appropriate when more specific cost estimates are developed for the Pickering B refurbishment, retirement, and the new nuclear build alternative, as well as inclusion of project specific risk considerations.

3.0 IMPACT ON CUSTOMER COST

Q. What is the purpose of the OPA's projection of the cost to customer?

A. The OPA has reviewed the cost of the plan in the previous section. The purpose of the cost to customer analysis is to provide a range of estimates of the cost impact on customers' bills that may result from the proposed Plan. Trying to forecast prices of electricity is an exercise fraught with uncertainties. The resource costs described in the previous sections are somewhat easier to forecast. However, there is still uncertainty in that exercise. Translating these resource costs into amounts paid by customers adds yet another level of uncertainty. There are other risks that create uncertainty and are difficult to quantify such as changes to the market structure, and future regulatory decisions. This analysis focuses on costs, not price, and shows magnitude, impacts,

trends, and patterns of a customer's bill under the major cost components that are paid by customers: commodity of electricity, conservation, transmission, wholesale market charges, debt retirement charges, and distribution, and the possible range of results.

Q. What is the confidence in the results of this analysis given all of the uncertainties?

A. The structure of the analysis and its ties to the production model of the Plan provides value in analysing the trends and ranges. The structure also allows understanding of the contribution of the individual components. The fact that it makes the costing assumptions explicit allows it to be used to reflect alternative costing assumptions. The way it has been used here provides a reasonable estimate of how cost to customers will evolve.

Q. How is the impact of the Plan on the cost to customer estimated?

A. The methodology used to determine the cost to customer is to disaggregate the cost of electricity into the following major cost categories:

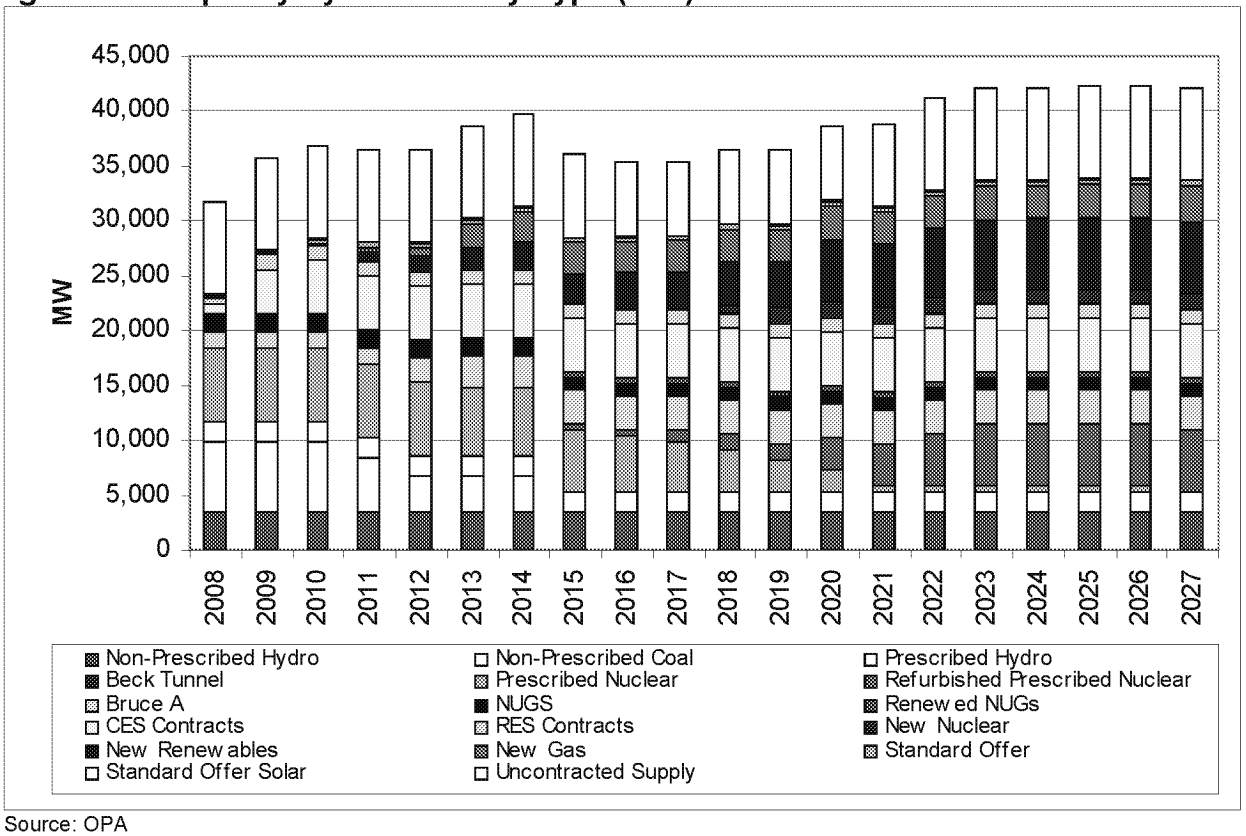
1) commodity (electricity) cost;
2) conservation costs;
3) transmission cost;
4) wholesale market charges;
5) debt retirement charge; and
6) distribution cost.

The cost to customer model estimates the costs for each cost category and converts the amount into a unit cost by dividing the cost category by the total system demand to generate proxy rates for each component.

Beginning with the commodity costs analysis, the energy produced is unbundled into facility types that share similar commercial or cost characteristics. Figure 14 , Table 3,

Figure 15 and Table 4 show the capacity and energy associated with these categories and how they evolve over time[1]. The limitation to this projection of the share of each category is that this unbundling is subject to the resource mix uncertainties in the medium and long-term and the way each category's cost is paid for may change over time.

Figure 14: Capacity by Commodity Type (MW)



Source: OPA

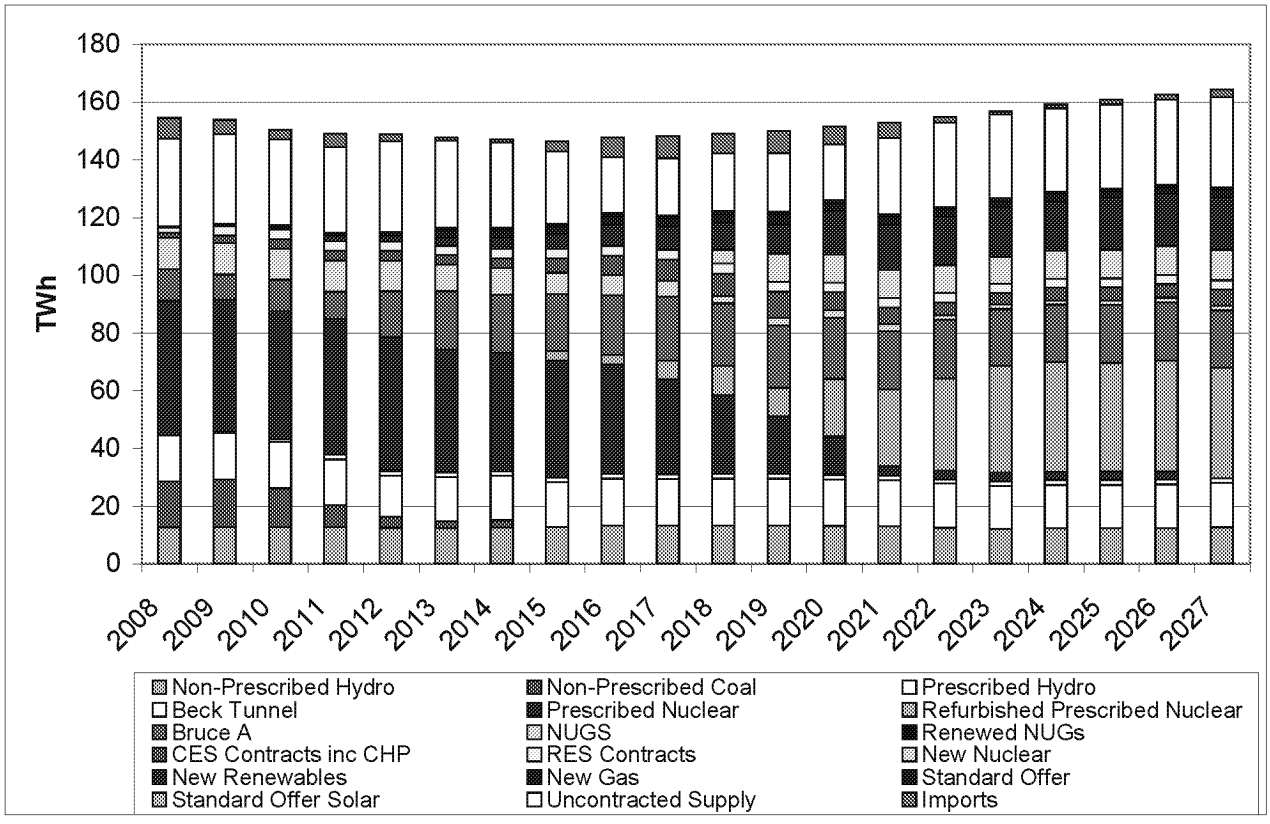
[1] All the results shown are for Plan A.

Table 3: Capacity by Commodity Type (MW)

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Non-Prescribed Hydro	3,469	3,469	3,469	3,469	3,469	3,469	3,469	3,469	3,469	3,469	3,469	3,469	3,469	3,469	3,469	3,469	3,469	3,469	3,469	3,469
Non-Prescribed Coal	6,343	6,343	6,343	4,878	3,232	3,232	3,232	-	-	-	-	-	-	-	-	-	-	-	-	-
Prescribed Hydro	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900
Beck Tunnel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Prescribed Nuclear	6,614	6,614	6,614	6,614	6,614	6,098	6,098	5,583	5,067	4,551	3,671	2,791	1,911	505	505	505	505	505	505	(547)
Refurbished Prescribed Nuclear	-	-	-	-	-	-	-	516	516	1,032	1,548	1,548	2,945	3,826	4,707	5,588	5,588	5,588	5,588	5,588
Bruce A	1,540	1,540	1,500	1,500	2,270	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040	3,040
NUGS	1,661	1,661	1,661	1,661	1,661	1,496	1,496	1,192	1,192	1,192	1,192	1,192	1,192	1,192	1,192	1,192	1,192	1,192	1,192	1,192
Renewed NUGs	-	-	-	-	-	165	165	469	469	469	469	469	469	469	469	469	469	469	469	469
CES Contracts	881	4,053	4,890	4,890	4,890	4,890	4,890	4,890	4,890	4,890	4,890	4,890	4,890	4,890	4,890	4,890	4,890	4,890	4,890	4,890
RES Contracts	611	1,301	1,301	1,301	1,301	1,301	1,301	1,301	1,301	1,301	1,301	1,301	1,301	1,301	1,301	1,301	1,301	1,301	1,301	1,301
New Nuclear	-	-	-	-	-	-	-	-	-	-	700	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400
New Renewables	113	196	216	1,022	1,376	1,867	2,455	2,835	3,438	3,563	4,013	4,163	5,783	5,811	6,382	6,382	6,411	6,546	6,546	6,546
New Gas	-	-	-	350	800	2,236	2,786	2,786	2,786	2,786	3,036	3,036	3,036	3,036	3,036	3,036	3,036	3,036	3,036	3,436
Standard Offer	88	187	385	385	385	385	385	385	385	385	385	385	385	385	385	385	385	385	385	385
Standard Offer Solar	29	68	88	88	88	88	88	88	88	88	88	88	88	88	88	88	88	88	88	88
Uncontracted Supply	8,398	8,398	8,398	8,398	8,398	8,398	8,398	7,583	6,768	6,768	6,749	6,782	6,782	7,584	8,398	8,398	8,398	8,398	8,398	8,398

Source: OPA

Figure 15: Energy Demand of Ontario Customers by Commodity type (TWh)



Source: OPA

Table 4: Energy Sales to Ontario Customers by Commodity Type (TWh)

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Non-Prescribed Hydro	13	13	13	13	12	12	13	13	13	13	13	13	13	13	12	12	12	12	12	13
Non-Prescribed Coal	16	17	13	7	4	2	3	-	-	-	-	-	-	-	-	-	-	-	-	-
Prescribed Hydro	16	16	16	16	14	15	15	16	16	16	16	16	16	16	15	15	15	15	15	15
Beck Tunnel	-	-	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Prescribed Nuclear	47	46	44	47	46	43	41	40	38	33	27	20	13	3	3	3	3	3	3	-
Refurbished Prescribed Nuclear	-	-	-	-	-	-	-	3	3	6	10	10	20	27	32	37	38	38	38	38
Bruce A	11	9	11	10	16	20	20	20	21	22	22	22	21	20	20	20	20	20	20	20
NUGS	11	11	11	11	11	9	9	7	7	6	3	3	3	3	2	2	2	2	2	2
Renewed NUGs	-	-	-	-	-	-	-	0	0	0	0	0	0	0	-	-	0	0	0	0
CES Contracts inc CHP	2	3	3	3	3	3	3	5	7	7	8	9	6	6	5	4	4	5	5	6
RES Contracts	2	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
New Nuclear	-	-	-	-	-	-	-	-	-	-	5	10	10	10	10	9	10	10	10	10
New Renewables	0	0	0	2	2	3	4	5	8	8	9	10	15	16	17	17	17	18	18	18
New Gas	-	-	-	-	-	2	2	2	3	3	3	3	3	2	2	2	2	2	2	2
Standard Offer	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Standard Offer Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Uncontracted Supply	30	31	30	30	32	30	30	25	19	20	20	20	19	26	29	29	29	29	29	31
Imports	7	5	3	5	2	1	1	4	7	8	7	8	6	5	2	1	1	2	2	3
Total	155	154	150	149	149	148	147	146	148	148	149	150	152	153	155	157	159	161	163	164

Source: OPA

The next step is to estimate the cost of the energy sales to Ontario customers by commodity type as shown in Table 4 above. These estimates, which are described in Attachment 1 to this exhibit, are not a prediction of exactly how the electricity will be sold, or under what commercial or settlement mechanism. The electricity may be sold through bilateral agreements between buyers and sellers, or load-serving entities and generators, or the OPA and generators, or on a regulated basis, or any other yet-to-be-developed market mechanism. The key value of the analysis is to first unbundle the commodity and then provide estimates of the costs, however settled and under any combination of market or regulated arrangements, and under various commercial arrangements.

Given the uncertainty of future costs, the analysis uses three scenarios: 1) high, 2) medium, and 3) low for the various commodity types. This scenario methodology recognizes the uncertainty associated with the possible future outcomes. Despite the many simplifications, trends emerge that bracket a credible range of possible generation cost implications on customers. There are possible scenarios that could likely move the costs outside the upper and lower bounds of the range identified. Nonetheless, the explicit assumptions made in this analysis are transparent and provide for the incorporation of different assumptions. Provided below in Table 5, Table 6 and Table 7 are the various cost assumptions per scenario for the commodity types. A detailed discussion of the methodology and underlying assumptions are provided in

Attachment 1 to this exhibit. The costs are presented in constant 2007 dollars, so that the underlying trends are not masked by the impact of inflation.

Table 5: Commodity Costs ($/MWh) – Median Scenario

	2010	2015	2020	2025
Non-Prescribed Hydro	35	43	43	38
Non-Prescribed Coal	35	43		
Prescribed Hydro	38	38	38	38
Beck Tunnel	69	69	69	69
Prescribed Nuclear	52	52	52	52
Refurbished Prescribed Nuclear	74	74	74	74
Bruce A	74	74	74	74
NUGS	98	112	103	72
Renewed NUGs	137	127	116	109
CES Contracts	177	142	128	145
RES Contracts	81	74	68	63
New Nuclear	86	86	86	86
New Renewables	85	85	85	85
New Gas	200	152	126	151
Standard Offer Dispatchable	104	95	87	80
Standard Offer	105	97	90	84
Standard Offer Solar	404	366	331	300
Uncontracted Supply	35	43	43	38
Imports	33	55	57	69

Source: OPA

Table 6: Commodity Costs ($/MWh) – Upper Scenario

	2010	2015	2020	2025		Change from Median			
						2010	2015	2020	2025
Non-Prescribed Hydro	55	63	63	58		20	20	20	20
Non-Prescribed Coal	55	63				20	20		
Prescribed Hydro	38	38	38	38		0	0	0	0
Beck Tunnel	69	69	69	69		0	0	0	0
Prescribed Nuclear	52	52	52	52		0	0	0	0
Refurbished Prescribed Nuclear	84	84	84	84		10	10	10	10
Bruce A	82	82	82	82		8	8	8	8
NUGS	118	132	123	92		20	20	20	20
Renewed NUGs	199	163	150	167		62	36	35	58
CES Contracts	199	163	150	167		23	21	22	22
RES Contracts	81	74	68	63		0	0	0	0
New Nuclear	110	110	110	110		24	24	24	24
New Renewables	94	94	94	94		9	9	9	9
New Gas	224	176	150	175		24	24	24	24
Standard Offer Dispatchable	104	95	87	80		0	0	0	0
Standard Offer Non-Dispatchable	105	97	90	84		0	0	0	0
Standard Offer Solar	404	366	331	300		0	0	0	0
Uncontracted Supply	55	63	63	58		20	20	20	20
Imports	53	75	77	89		20	20	20	20

Source: OPA

Table 7: Commodity Costs ($/MWh) – Lower Scenario

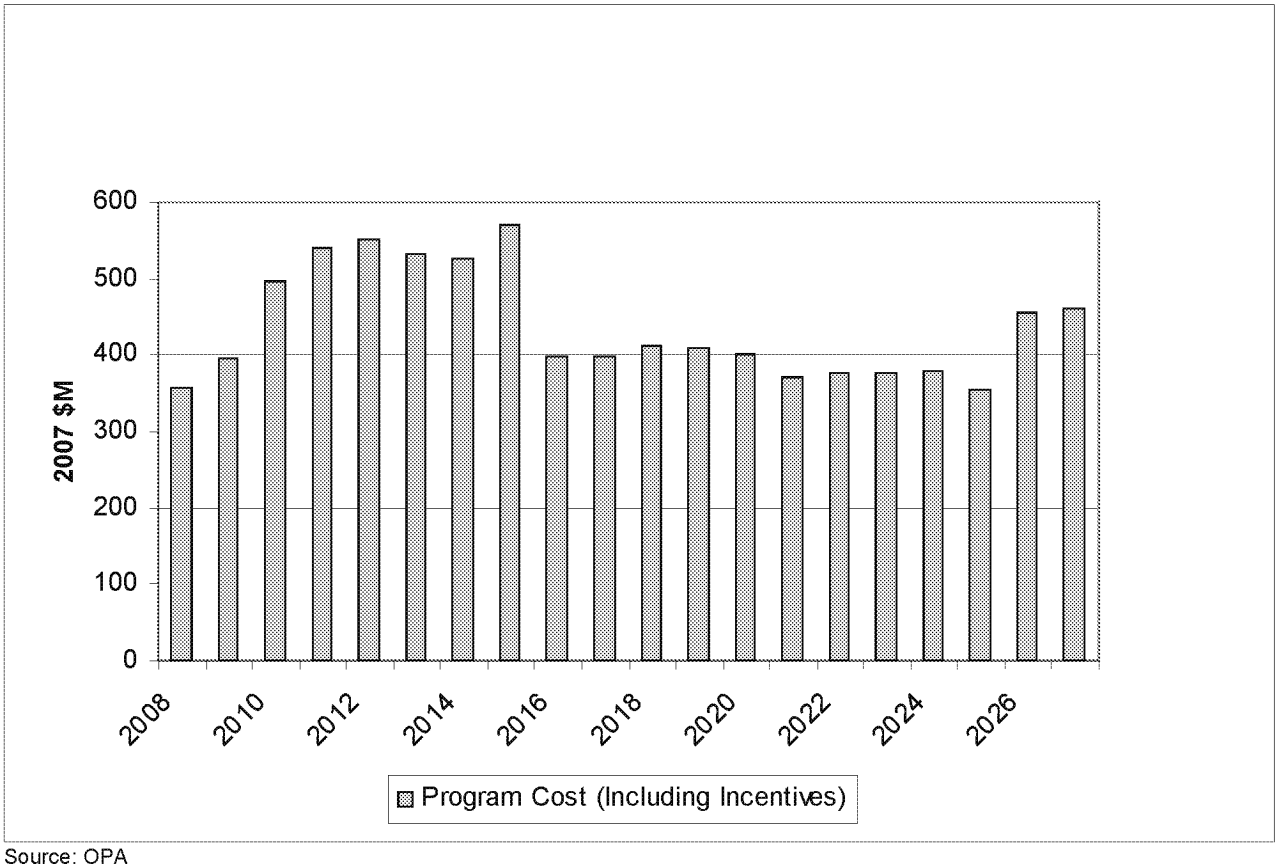
	2010	2015	2020	2025		Change from Median			
						2010	2015	2020	2025
Non-Prescribed Hydro	25	33	33	28		-10	-10	-10	-10
Non-Prescribed Coal	25	33				-10	-10		
Prescribed Hydro	33	33	33	33		-5	-5	-5	-5
Beck Tunnel	69	69	69	69		0	0	0	0
Prescribed Nuclear	50	50	50	50		-3	-3	-3	-3
Refurbished Prescribed Nuclear	64	64	64	64		-10	-10	-10	-10
Bruce A	74	74	74	74		0	0	0	0
NUGS	88	102	93	62		-10	-10	-10	-10
Renewed NUGs	25	33	33	28		-113	-94	-82	-81
CES Contracts	148	112	100	115		-29	-29	-27	-30
RES Contracts	81	74	68	63		0	0	0	0
New Nuclear	65	65	65	65		-21	-21	-21	-21
New Renewables	85	85	85	85		0	0	0	0
New Gas	186	138	112	137		-14	-14	-14	-14
Standard Offer Dispatchable	104	95	87	80		0	0	0	0
Standard Offer	105	97	90	84		0	0	0	0
Standard Offer Solar	404	366	331	300		0	0	0	0
Uncontracted Supply	25	33	33	28		-10	-10	-10	-10
Imports	23	45	47	59		-10	-10	-10	-10

Source: OPA

The cost of generation is produced as a product of multiplying the electricity commodity costs with the generation's energy production.

The next cost category estimates are for conservation costs, transmission, wholesale market services, debt retirement costs and distribution costs, whose costs are shown in Figure 16, Figure 17, Figure 18, Figure 19, and Figure 20, and in Table 8, Table 9, Table 10, Table 11, and Table 12. The derivation of these cost estimates is discussed in detail in Attachment 1.

Figure 16: Cost of Conservation Programs (2007 $Millions)



Source: OPA

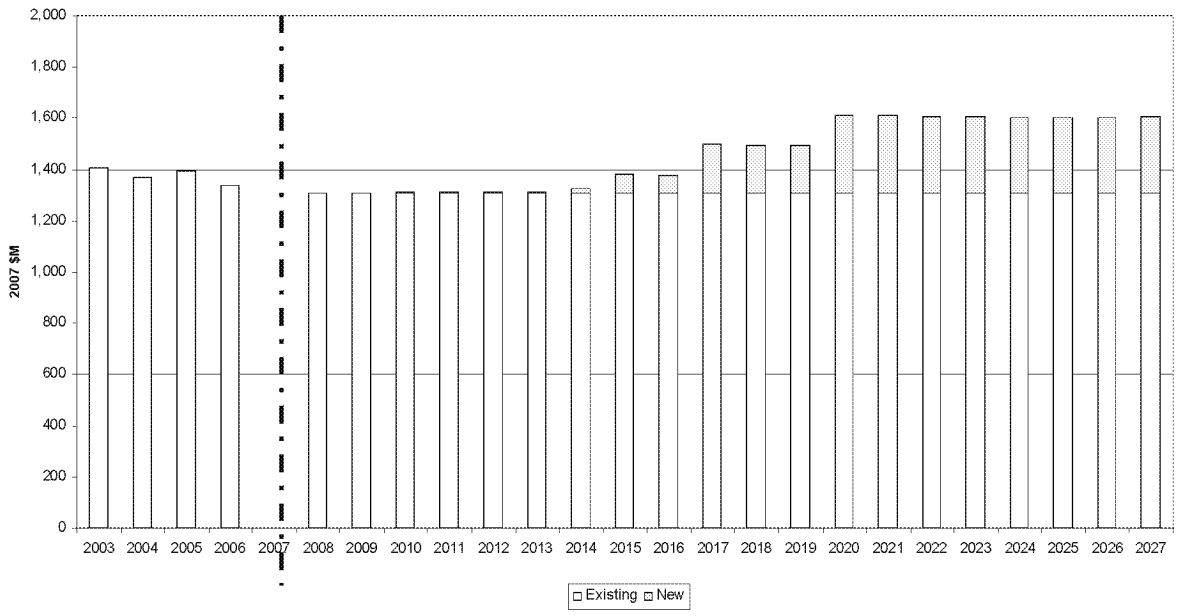
Table 8: Conservation Costs ($Millions)

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Program Cost (including incentives)	356	396	495	540	550	533	528	570	397	400	411	409	401	372	376	376	380	354	455	460

Source: OPA

The above Conservation cost (program and incentive costs) for the cost to customer model is found in Exhibit D-4-1.

Figure 17: Cost of Transmission (2007 $Millions)



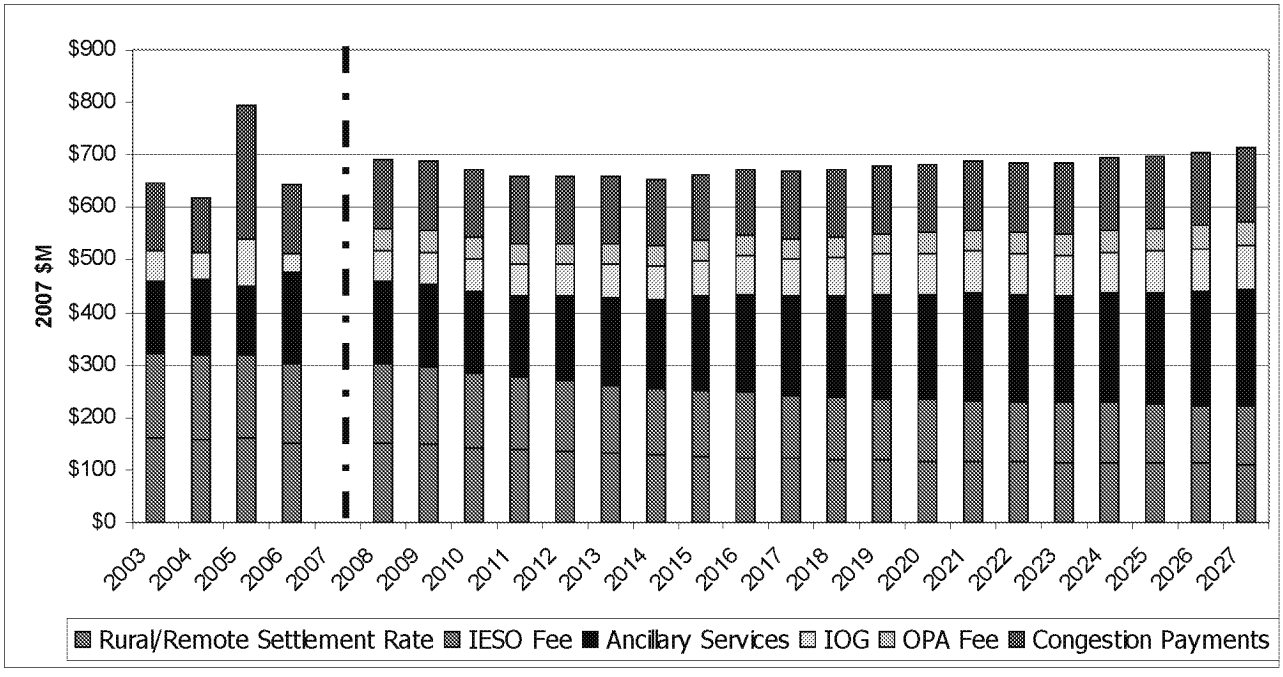
Source: OPA

Table 9: Cost of Transmission ($Millions)

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Existing	1,406	1,369	1,393	1,340	-	1,305	1,305	1,305	1,305	1,305	1,305	1,305	1,305	1,305	1,305	1,305	1,305	1,305	1,305	1,305	1,305	1,305	1,305	1,305	1,305
New	-	-	-	-	-	-	-	6	5	5	5	21	75	72	192	190	190	306	303	301	299	297	295	297	300

Source: OPA

Figure 18: Cost of Wholesale Market Service Charges (2007 $Millions)



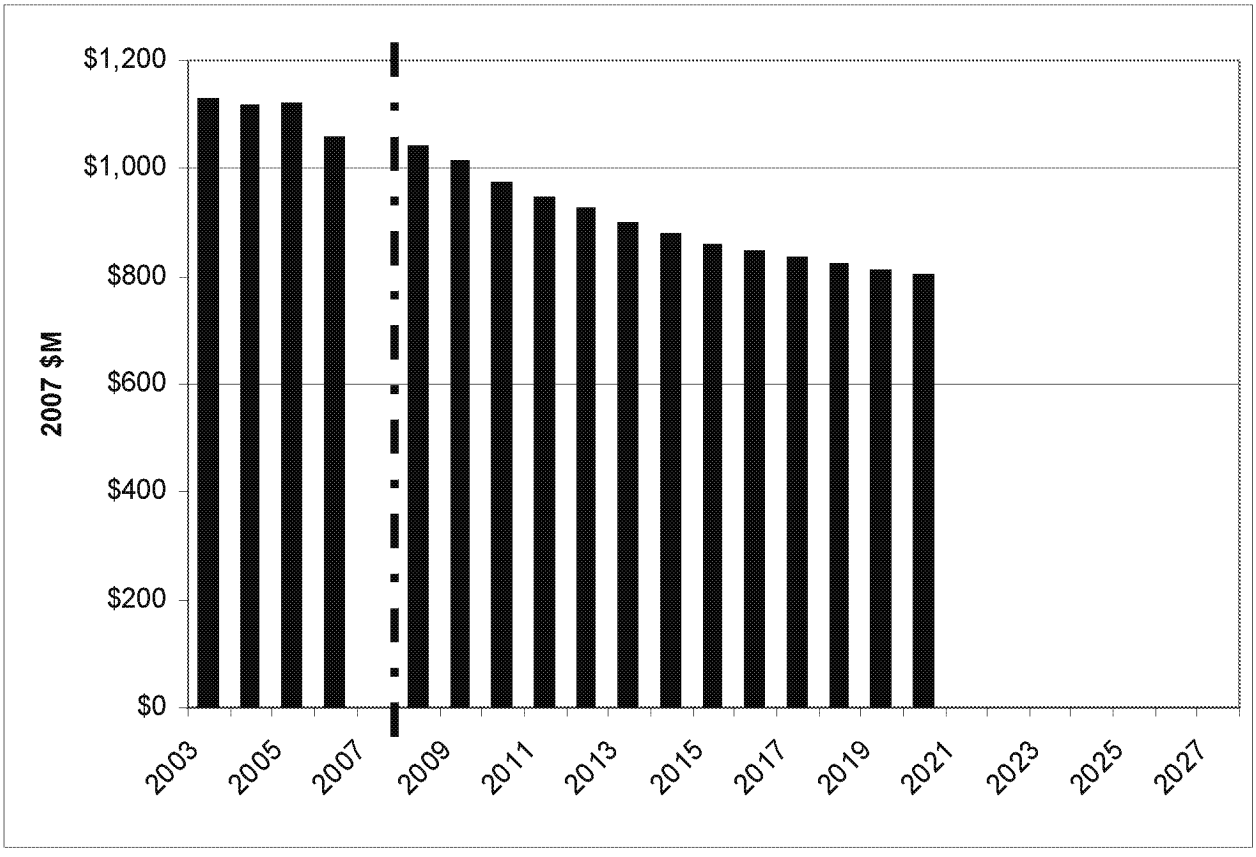
Source: OPA

Table 10: Cost of Wholesale Market Service Charges ($Millions)

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Congestion Payments	128	102	252	130	-	133	132	129	128	128	127	126	126	127	127	128	129	130	131	133	135	137	138	140	141
Rural/Remote Settlement Rate	161	159	160	151	-	151	148	141	137	134	131	128	125	123	121	120	118	117	116	115	114	113	112	111	110
IESO Fee	161	162	163	134	-	123	123	120	119	119	118	117	117	118	118	119	120	121	122	124	125	127	129	130	131
OPA Fee	-	-	-	-	-	41	41	40	39	39	39	39	39	39	39	39	40	40	41	41	42	42	43	43	44
IOG	58	52	90	36	-	59	60	60	60	62	64	64	69	71	71	73	75	77	78	77	78	79	81	82	84
Ancillary Services	137	144	131	175	-	156	159	159	157	162	167	168	181	188	188	191	198	202	206	204	204	209	212	217	222
Wholesale Charges	646	619	796	625	-	664	663	650	641	644	646	642	656	667	666	670	681	687	694	694	697	708	714	723	733

Source: OPA

Figure 19: Cost of Debt Retirement Charge (2007 $Millions)



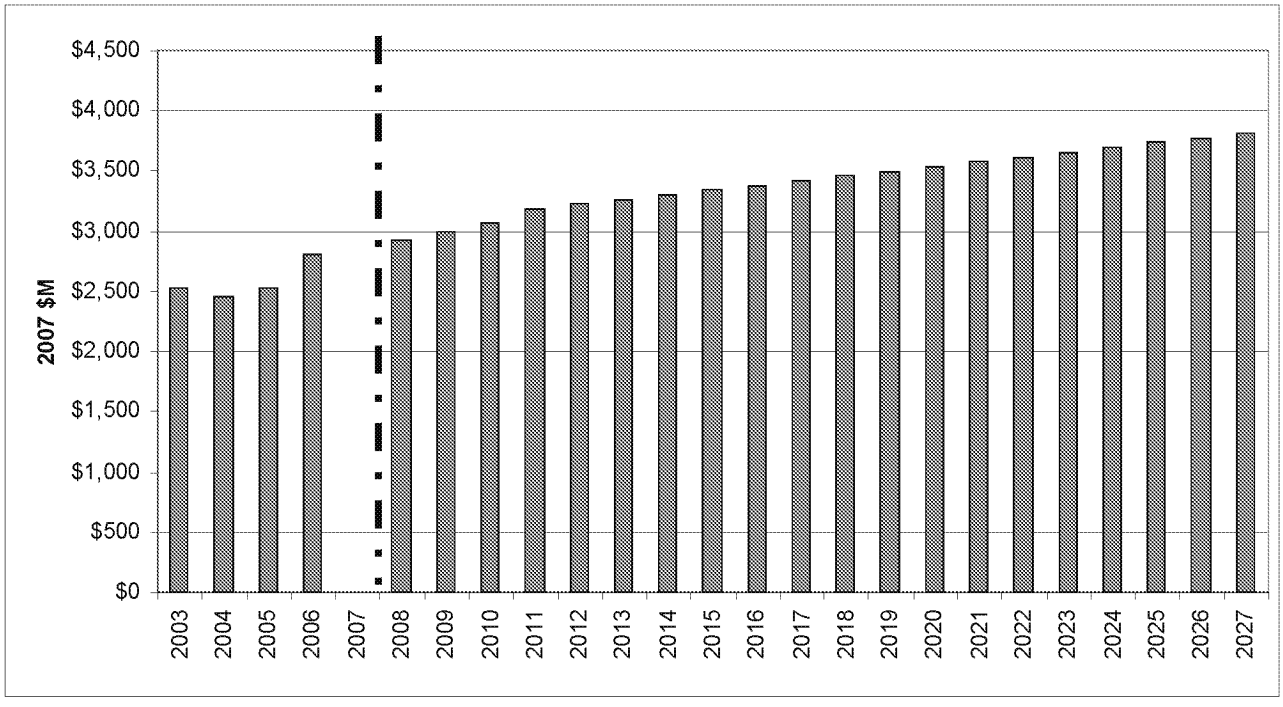
Source: OPA

Table 11: Cost of Debt Retirement Charge ($Millions)

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
DRC ($M)	1,127	1,117	1,121	1,057	-	1,040	1,015	973	945	925	900	878	858	848	834	823	812	804	0	0	0	0	0	0	0

Source: OPA

Figure 20: Cost of Distribution (2007 $Millions)



Source: OPA

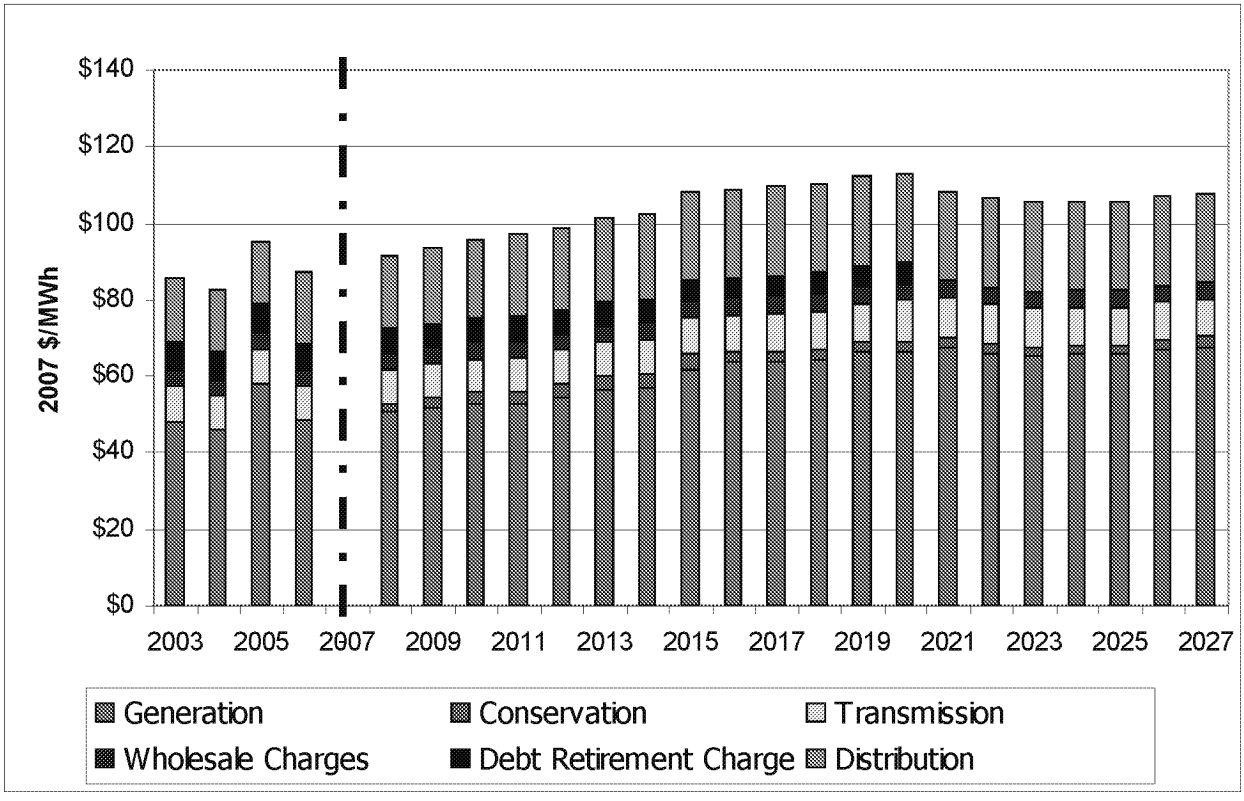
Table 12: Cost of Distribution ($Millions)

$ Million	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Dx costs	2,534	2,455	2,523	2,805	-	2,921	2,993	3,072	3,187	3,226	3,265	3,304	3,343	3,381	3,419	3,457	3,495	3,533	3,573	3,614	3,654	3,694	3,735	3,775	3,815

Source: OPA

Once all of the cost estimates are completed for the major electricity categories, the unit costs are aggregated together to produce the average cost per MWh. This is shown in Figure 21 and in Table 13.

Figure 21: Average Unit Cost (2007 $/MWh)



Source: OPA

Table 13: Average Unit Cost (2007 $/MWh)

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Generation	48	46	58	48	-	51	52	53	53	54	57	57	62	64	63	64	66	67	67	66	65	66	66	67	68
Conservation	0	0	0	0	-	2	3	3	3	3	3	3	4	3	3	3	3	3	2	2	2	2	2	3	3
Transmission	9	9	9	9	-	8	8	9	9	9	9	9	9	9	10	10	10	11	11	10	10	10	10	10	10
Wholesale charges	4	4	5	4	-	4	4	4	4	4	4	4	4	5	4	4	5	5	5	4	4	4	4	4	4
DRC	7	7	7	7	-	7	7	6	6	6	6	6	6	6	6	6	5	5	0	0	0	0	0	0	0
Distribution	17	16	16	19	-	19	19	20	21	22	22	22	23	23	23	23	23	23	23	23	23	23	23	23	23

Source: OPA

It should be noted that, due to losses in the transmission and distribution systems, the average unit cost to customers will be higher than the values shown.

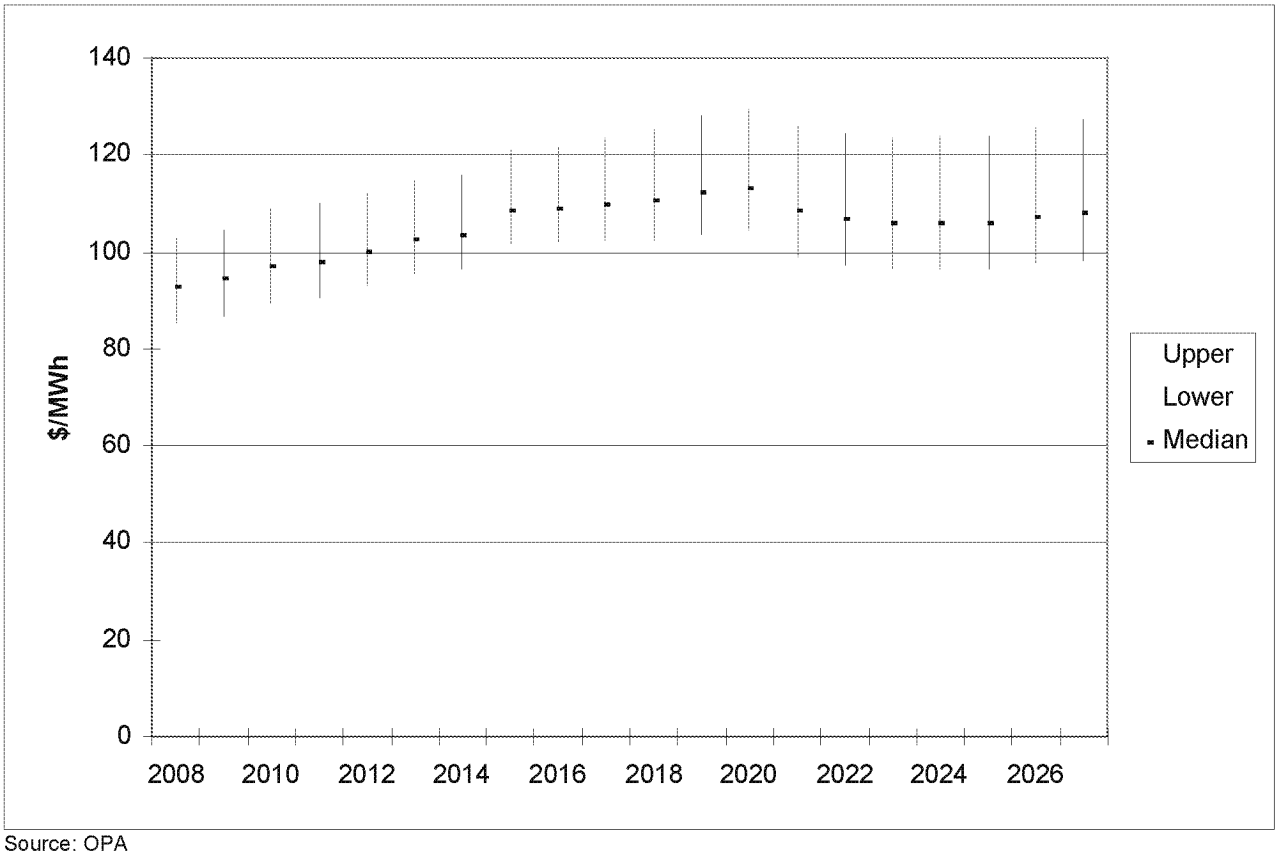
It will be seen that the unit costs are expected to rise until about 2020. After that time they should decrease, driven largely by the increased amounts of energy coming from the refurbished nuclear plant and from the end of the debt retirement charge.

As a means of providing some relative benchmarking to history for the cost of the Plan, the historical actuals for the last four complete years (2003 to 2006) are provided in the above graphs. The historical commodity charge, transmission, wholesale market service charges, and the Ontario Demand were obtained from the IESO. The Debt Retirement Charge historical cost is derived from the government rate and the Ontario Demand. The historical distribution costs were obtained from the OEB's published distribution revenue data posted on the Board's website.

Q. How uncertain are these cost estimates?

A. There is considerable uncertainty in making these estimates. Figure 22 and Table 14 provided below show a range in the unit costs.

Figure 22: Range of Unit Cost Estimates ($/MWh)



Source: OPA

Table 14: Range of Unit Cost Estimates ($/MWh)

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Upper	103	104	109	110	112	115	116	121	122	123	125	128	129	126	124	123	124	124	126	127
Lower	85	87	89	90	93	96	96	101	102	102	102	103	105	99	97	96	97	97	98	98
Median	93	94	97	98	100	102	103	108	109	110	110	112	113	108	107	106	106	106	107	108

Source: OPA

Q. What is the cost to customer for the Plan period?

A. Table 15 below provides the cost per MWh for each cost category of the cost to customer model for the range of estimates. As illustrated in Table 15, the Debt Retirement Charge is assumed to no longer be a cost to customers as the stranded debt is estimated to be eliminated by 2021.

Table 15: Contribution to Unit Costs (2007 $/MWh)

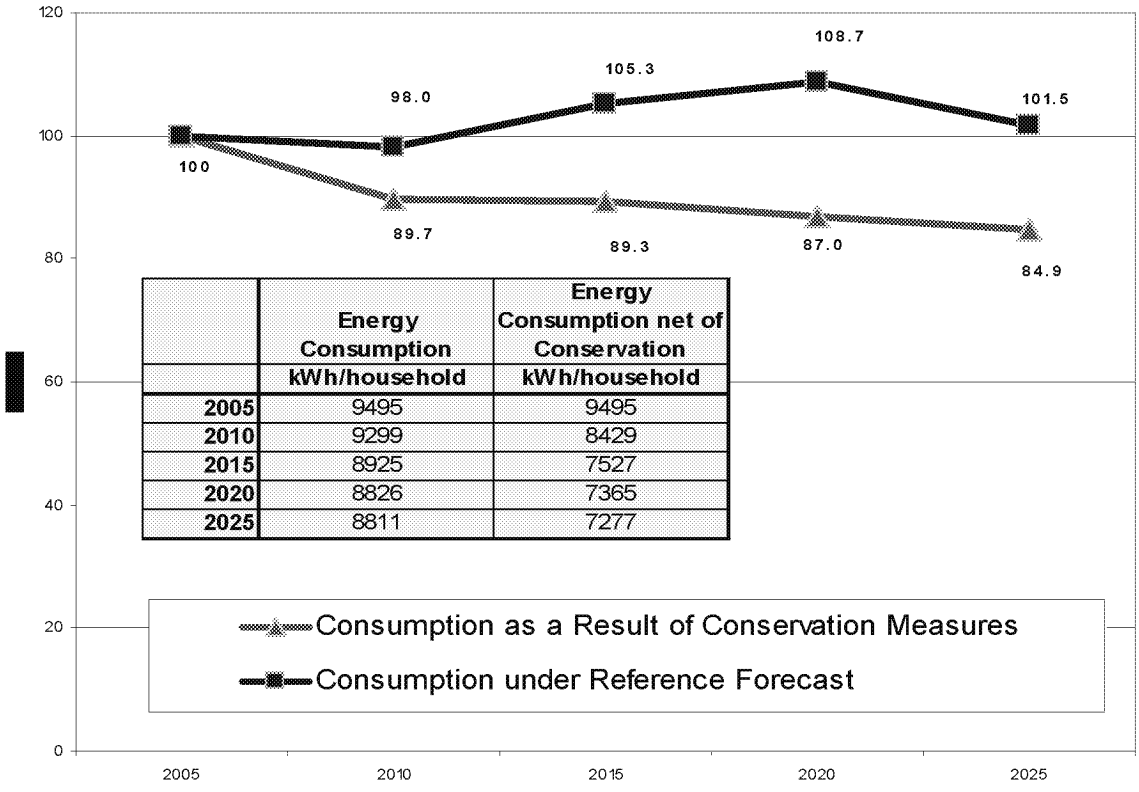
	UNIT RATES ($2007/MWh)							
MEDIAN	2003	2004	2005	2006	2010	2015	2020	2025
Conservation (*)					$3.29	$3.90	$2.65	$2.20
Transmission	$9.27	$8.93	$8.87	$8.87	$8.72	$9.43	$10.63	$9.95
Wholesale & net settlement	$5.47	$5.57	$6.85	$5.28	$4.34	$4.48	$4.53	$4.44
Debt Retirement Charge	$7.43	$7.28	$7.14	$7.00	$6.47	$5.86	$5.31	$0.00
Distribution	$16.70	$16.00	$16.08	$18.57	$20.43	$22.84	$23.31	$23.22
Generation	$47.99	$46.17	$57.76	$48.42	$53.52	$61.80	$66.63	$65.95
UPPER BOUND								
Conservation					$3.62	$4.29	$2.91	$2.42
Transmission					$9.59	$10.37	$11.69	$10.94
Wholesale					$4.34	$4.48	$4.53	$4.44
Debt Retirement Charge					$6.47	$5.86	$5.31	$0.00
Distribution					$21.26	$24.97	$26.80	$28.05
Generation					$63.94	$71.14	$78.20	$78.22
LOWER BOUND								
Conservation					$2.96	$3.51	$2.38	$1.98
Transmission					$7.85	$8.48	$9.57	$8.95
Wholesale					$4.34	$4.48	$4.53	$4.44
Debt Retirement Charge					$6.86	$6.22	$5.63	$0.00
Distribution					$20.43	$22.84	$23.31	$23.22
Generation					$46.93	$55.81	$59.15	$58.00
* Historicaly, conservation costs are included in the Distribution costs								
Total Cost to Customer - Lower					$89	$101	$105	$97
Total Cost to Customer - MEDIAN	**$87**	**$84**	**$97**	**$88**	**$97**	**$108**	**$113**	**$106**
Total Cost to Customer - UPPER					$109	$121	$129	$124

Source: OPA
* Conservation costs prior to 2007 are included within Distribution costs

The impact of these cost changes will be different for various customers according to their consumption patterns, levels of conservation, time of use, local service terms and conditions, and contracts they may enter into for services.

Figure 23 shows the trend in a typical householder bill for the median scenario based on an assumed monthly bill, in 2005, of $100. The unit rates are applied to a typical household bill over the Plan period. Household consumption will be reduced as a result of achieving the planned Conservation goals. It should be noted that the unit cost in 2005 was an historical high. Using an alternative base year would show higher increases in the 2005 to 2010 time period. The 2005 historical year was maintained as the base year to allow for a consistent presentation to that made in Discussion Paper 7.

Figure 23: Impact on Representative Residential Electricity Bill (2007 $)



	Energy Consumption kWh/household	Energy Consumption net of Conservation kWh/household
2005	9495	9495
2010	9299	8429
2015	8925	7527
2020	8826	7365
2025	8811	7277

Source: OPA

Figure 23 indicates that a representative household electricity bill will be reduced (in constant 2007 dollars) by the implementation of the Conservation plan,

Q. What changes have been made to the cost to customer model since Discussion Paper 7?

As a result of review and input from industry participants, some refinements were made to the Cost to Customer model. Some of the changes made are as follows:

- Inclusion of a median scenario;
- OPG Prescribed Assets price is refined to reflect an increased rate of return and the recovery of regulatory asset costs;
- Inclusion of a commodity type for the Beck Tunnel dispatch;
- Clean Energy Supply contract estimate is refined to recognize the individual contracts and the average capacity factor, with a possible range of natural gas prices based on a Monte Carlo analysis;
- NUG price is updated to information received from the Ontario Electricity Financial Corporation;
- Ancillary service costs are escalated at the same rate as the change to the overall commodity costs, given that these ancillary services form a joint product;
- 20 percent of the non-solar Renewable Energy Standard Offer Program cost is escalated by inflation consistent with the current program rules;
- Imports have been included as a commodity type;
- Solar RESOP cost is fixed at $420/MWh in nominal terms, consistent with current program rules;
- Rural or Remote Settlement rate is held constant in nominal dollars.
- Distribution costs include smart meter costs and escalate with household additions.

These changes have been incorporated into the methodology and are described in the assumption paper for the costs to customer model as provided in Attachment 1.

ATTACHMENT 1

METHODOLOGY AND ASSUMPTIONS FOR THE COST TO CUSTOMER MODEL

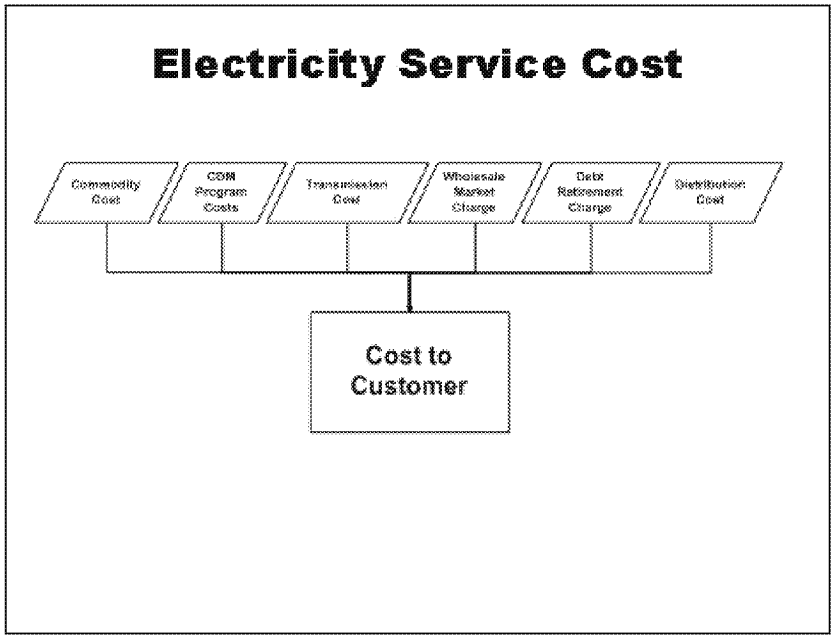
1.0 INTRODUCTION

The IPSP evidence lays out the generation, transmission and Conservation programs that will be required to ensure there is an adequate, reliable and sustainable electricity sector to meet the needs of Ontarians. The costs associated with the infrastructure for the electricity system and the electricity commodity costs are borne by the electricity consumers of Ontario through the price they pay for the electricity they use. The cost to customer model was developed to determine the impact of the Plan's initiatives on the monies paid by electricity consumers. For the IPSP cost to customer analysis, the cost of electricity is broken down and categorized into the following major cost components:

- commodity (electricity) cost;
- Conservation costs;
- transmission cost;
- wholesale market charge;
- debt retirement charges; and
- distribution cost.

This breakdown is illustrated in Figure 1.

Figure 1: Electricity Service Cost Schematic



Source: OPA

The cost to customer model consolidates estimates of each of these components. It presents results on both a total basis and on an average annual per unit basis. It does not attempt to allocate costs on a customer class basis.

The underlying assumptions for each of the cost components are described in the following sections.

2.0 COMMODITY (ELECTRICITY) COST

The commodity cost component is the payment to the generators for the production of the electricity commodity. The cost is different for each facility, as it depends on whether the generator is paid a regulated price established by legislation/regulatory order, has an obligation to supply its production based on a contractual agreed price, or is selling at the market-clearing price for electricity. As a result, the Ontario electricity commodity price paid by customers is comprised from a combination of market price, regulated price and contract price arrangements.

The calculation of the commodity cost in the cost to customer model takes the energy production of each facility from the dispatch model of PSM, and links it to a payment method appropriate for the generator.[1] For example, there is a direct linking of the energy produced from OPG's nuclear generation stations (specifically Darlington and Pickering) to the prescribed fixed rates established by the government as the cost the customer will pay for this generation (currently the government establishes this price, but in the future this rate will be set by the OEB). Thus while OPG will receive revenue from the IESO based on the market clearing price, there are periodic settlements to ensure that OPG only receives the regulated price. The difference between the regulated or contract price to the HOEP is captured in a global adjustment, which is the variance amount required to be paid for the loads to ensure that the payment to the generator is equal to the contract or regulated price. In the cost to customer model this mechanism is short cut, with the model directly allocating the regulated price to the output of OPG generators to give OPG's revenue, and hence the cost paid by customers.

The organization of the commodity costs methodology discussion is to group a list of facility types into the following major categories: 1) Regulated Price, 2) Contract Price, 3) Market Clearing Price; and 4) New Generation and Refurbishment of Existing Facilities.

The specific content layout for these major categories and facilities are reviewed and discussed as follows:

1. Regulated Facilities
    a) OPG Prescribed Assets
    b) OPG Non-Prescribed Assets
2. Contract Price
    a) Non-Utility Generators
    b) OPA Contracts
        (i) Bruce Power

[1] The model only takes that part of the generator output that is dedicated to meeting Ontario loads. Export revenue is not factored into the model. Imports are included as a commodity type.

(ii) Renewable Energy Supply
(iii) Clean Energy Supply
(iv) Standard Offer (Dispatchable/Non-Dispatchable/Solar)

3. Market Clearing Price
4. New Generation Units and Refurbishment of Existing Facilities
   a) New Nuclear
   b) Refurbished Nuclear
   c) New Gas Fired Generation
   d) New Renewables
   e) Beck Tunnel

The mechanism by which new generators and owners of refurbished facilities will recover their cost is not known at this time. It is likely to be a combination of the above mechanisms. In most cases the cost to customer model assumes a contract price.

The derivation of the costs used for each generator in each category will now be addressed in more detail, along with the costing assumptions for new and refurbished generation facilities.

2.1 Regulated Price Facilities

A significant portion of OPG's generation facilities have their production priced at a rate that has been established by legislation or regulatory order. Table 1 summarizes the current regulatory regimes that apply to various OPG generators.

Table 1: OPG Generator Regulatory Regime

OPG Prescribed Assets	OPG Non-Prescribed Assets	
	Revenue Limited (Set Price)[1]	Merchan[t2]
Baseload Hydro Production <= 1,900 MW	85% of Intermediate & Peaking Hydro Production	Baseload Hydro Production > 1,900 MW
All Nuclear Production	85% of All Coal Production	15% of remaining revenue limited production from coal and hydro
		Lennox output

Notes: 1. See section 2b below.
2. Market-clearing price or reliability-must-run contract
Source: OPA

Further details of each of these categories, and the prices assumed are described below:

2.1.1 Ontario Power Generation Prescribed Assets

The OPG prescribed assets are baseload generation stations owned by Ontario Power Generation ("OPG") that provide electricity consistently thorough the day or night. The prescribed generation facilities are the nuclear generating stations operated by OPG (Pickering and Darlington) and OPG's baseload hydroelectric generation facilities (De Cew I, De Cew II, Sir Adam Beck I, Sir Adam Beck II, Sir Adam Beck pumped generating station and R.H. Saunders).

Currently, OPG receives a fixed rate of 3.3 cents/kWh for the first 1,900 MW of electricity generated by the baseload hydroelectric stations in any given hour. Output over 1,900 MW receives the market-clearing price. For the nuclear plants, OPG receives a fixed rate of 4.95 cents/kWh. These current rates have been set by the government to apply until March 31, 2008. After the expiry of these rates, the Ontario Energy Board will have the authority to determine payment amounts for the prescribed generation facilities commencing on April 1, 2008.

On March 21, 2006, the OEB initiated a process to establish a methodology to determine the price that should be paid for the OPG prescribed assets to be effective after the expiry of the government set rates. The regulatory models presented by the OEB for discussion in this process were: 1) cost of service, 2) incentive regulation, and 3) regulatory contracts.

On July 6, 2006, a Discussion Paper was issued by Board staff regarding the regulatory methodology for setting payment amounts for the prescribed generation assets. This paper proposed an incentive regulation model.

On November 30, 2006, the Board released a report entitled " A Regulatory Methodology for Setting Payment Amounts for the Prescribed Generation Assets of Ontario Power Generation Inc.", whereby the Board accepted the staff's recommendation that in the longer term, the methodology for setting payments would be based on incentive regulation. At

page 11 of that report, however, the Board found that: instead of using the existing payments as a base payment,

> for the incentive regulation formula, the Board will undertake a series of limited issues cost of service processes to set the base payment. The Board will extend the limited cost of service process over several payment orders until all relevant issues have been examined. The Board will implement an incentive regulation formula when it is satisfied that the base payment provides a robust starting point for that formula.

The Board concluded that the initial cost of service payment amounts for the prescribed generation assets should be limited to OM&A and rate of return, with each of the nuclear and hydroelectric businesses being reviewed separately. With respect to the prescribed hydroelectric assets, the Board will also consider the impact of the Beck tunnel expansion on OPG's costs and revenue requirement. In addition, to the prescribed rates, the Board will also address the recovery of balances in the variance and deferral accounts identified in O. Reg. 53/03.

Given the possible change to the prescribed hydroelectric and nuclear costs for a higher rate of return, and the recovery of the variance and deferral account balances, a derivation of the prescribed rates was developed from the schedule entitled "Forecast Information (as of Q3/2004) for Facilities Prescribed under Ontario Regulation 53/05", as posted on the OEB website, and deferral account balances from the 2006 Annual Report for OPG.

Based on the forecast information and annual report data, the prescribed cost for nuclear would be $52 per MWh and the prescribed hydroelectric rate would be $38 per MWh for the first 1,900 MW. These prescribed rates reflect a 10% return and the recovery of regulatory asset costs for the medium and high scenarios in the cost to customer model.

For the low case scenario the OPA assumes the last established licensed price for the OPG prescribed units, which is held constant in real terms for the period of the Plan. Specifically, the commodity cost is $33 per MWh for the first 1,900 MW of hydroelectric generation, and $49.5 per MWh for nuclear production for the term of the IPSP.

Table 2 below summarizes the values used.

Table 2: Costs for Prescribed Assets ($/MWh)

	Base Load Hydro Production	Nuclear Production
High	38	52
Median	38	52
Low	33	49.5

Source: OPA

2.1.2 OPG Non-Prescribed Assets

The OPG non-prescribed assets are also categorized in the Cost to Customer model as having a regulated rate as the revenue for these facilities is determined by the OPG license conditions arising from a direction from government to the OEB. The list of OPG non-prescribed assets by hydroelectric and fossil-fired generation is as follows:

Table 3: Non-Prescribed Hydroelectric generation

Abitibi Canyon GS	Kipling GS
Aguasabon GS	Lakefield GS
Alexander Falls GS	Little Long GS
Arnprior GS	Lower Notch GS
Auburn GS	Lower Sturgeon Falls GS
Barrett Chute GS	Manitou Falls GS
Big Chute GS	Matabitchuan GS
Big Eddy GS	McVittie GS
Bingham Chute GS	Merrickville GS
Calabogie GS	Meyersburg GS
Cameron Falls GS	Mountain Chute GS
Caribou Falls GS	Nipissing GS
Chats Falls GS	Otter Rapids GS
Chenaux GS	Otto Holden GS
Coniston GS	Pine Portage GS
Crystal Falls GS	Ragged Rapids GS
Des Joachims GS	Ranney Falls GS
Ear Falls GS	Sandy Falls GS
Elliott Chute GS	Seymour GS
Eugenia GS	Sidney GS
Frankford GS	Sills Island GS
Hagues Reach GS	Silver Falls GS
Hanna Chute GS	Smoky Falls GS
Harmon GS	South Falls GS
High Falls GS	Stewartville GS
Hound Chute GS	Stinson GS
Indian Chute GS	Tretheway Falls
Kakabeka GS	Wawaitin Falls GS
	Whitedog Falls GS

Source: OPA

Table 4: OPG Non-Prescribed Fossil fired Units

Atikokan
Lambton
Nanticoke
Thunder Bay

Source: OPA

The government has established that OPG non-prescribed assets have a revenue limit and the variance between the amount the generator obtains from Hourly Ontario Energy Price ("HOEP") and its set price is captured through an OPG rebate.

The Ontario government has established a rebate on 85 percent of the output from these stations by way of refunding monies collected above a set price. This rebate is known as the OPG Rebate. On February 9, 2006, the government announced an initiative to improve price stability for consumers, by extending and initially lowering the transitional revenue limit as follows:

- 4.6 cents/kWh from May 1, 2006, to April 30, 2007;
- 4.7 cents/kWh from May 1, 2007, to April 30, 2008; and
- 4.8 cents/kWh from May 1, 2008, to April 30, 2009.

The OPG rebate ensures that the facilities are paid the capped rate for 85 percent of their output and that appropriate credit will flow to the customer. The generation in excess of the 85 percent receives the market clearing price.

For the IPSP Plan, the cost to customer model assumes in the medium and low scenarios that the last revenue cap established by the government of 4.8 cents/kWh for 85% of the volumes is maintained in real terms for the planning horizon.

For the high scenario in the model it is assumed that all volumes from the non-prescribed hydro and coal facilities will be set to equal the market clearing price, upon expiry of the government legislated cap in 2010.

Table 5: Summary of Costs of OPG Non-Prescribed Assets

	$/MWh
High	Market Clearing Price ("MCP") in 2010
Median	Minimum of 48 and MCP
Low	Minimum of 48 and MCP

Source: OPA

2.2 Contract Price

The contract price facilities include the non-utility generators ("NUGs"), and OPA contracts (i.e., Bruce Power, OPA RES, OPA CES, and Standard Offer (Dispatchable/Non-Dispatchable/Solar). For the contract price facilities, the variance between the amount the

generator obtains from HOEP and its contract price is captured through the global adjustment factor. The global adjustment ensures that the contract price negotiated by the generator is the price they receive for their generation. In the Cost to Customer model, generators are assumed to be paid at the contract rate, rather than through a combination of HOEP and global adjustment.

2.2.1 Non-Utility Generators

The NUGs are privately owned generators who signed contracts with the former Ontario Hydro that are still in force today. The NUG contracts expire at various dates up to 2048. The Ministry of Finance estimates that the bulk of the existing electricity contracts will expire in twelve years. Currently, total capacity of the NUGs portfolio is about 1,700 MW or about six percent of Ontario's generating capacity.

Many of these NUG power purchase agreements ("PPAs") employed the Ontario Hydro Direct Customer Rate ("DCR") as the price index. However, the former Ontario Hydro's DCR ceased to exist on May 1, 2002 upon the commencement of the open market for electricity in Ontario. As a result, it was necessary to establish a replacement DCR to continue the administration of the PPAs. The Board of Directors of the Ontario Electricity Financial Corporation ("OEFC") approved the proposed replacement for the DCR set out in the Working Paper dated June 24, 2002, for use as the price index in the revision of PPAs. The replacement index is referred to as DCRnew.

As outlined in the Working Paper, DCRnew is derived from the total market cost ("TMC") of electricity delivered on a 100% load factor firm basis to a wholesale market participant load customer connected at either 230 kV, 115 kV or under 115 kV. At the commencement of the open market TMC comprised the following items totaled and averaged over the year:

- Hourly Ontario Energy Price;
- Wholesale Market Service Charges, including
    - Hourly Uplift Settlement Charges;
    - Monthly Uplift Charges;

- IMO (now the IESO) Administration Charge; and
- Rural and Remote Electricity Rate Protection

- Transmission Service Charges (network, line connection and transformation depending on the voltage level);
- Debt Retirement Charge; and
- OPGI Market Power Mitigation Rebate ("MPMR")

On April 27, 2006, the TMC calculation was updated recognizing the global adjustment and the ONPA rebate. The ultimate result is a TMC unit rate that is equivalent to the cost of electricity in the Ontario market place, with the exception of the distribution costs.

Given that the NUG contracts are confidential contracts, the specific pricing of these terms for each contract is not available for establishing the commodity cost component of the cost to customer model. Instead, OEFC provided going forward estimates of the average NUG payments and volume, with a forecast of annual escalation in the average NUG price, based on OEFC's proprietary NUG master model and estimated changes in the Total Market Cost. For the high case scenario the cost were incremented by $20/MWh and in the low scenario they where decremented by $10/MWh, in line with the range assumptions for the market clearing price and the cost of imports. The table below shows the values used.

Table 6: NUG Commodity Price ($/MWh)

	2010	2015	2020	2025
High	118	132	123	92
Median	98	112	103	72
Low	88	102	93	62

Source: OPA

As the NUG contracts expire it is assumed that the dispatch from these facilities will receive a price similar to the OPA CES contract price for the high case scenario. The low case scenario assumes the expired NUG contracts will receive the market clearing price. The medium scenario assumes a contract price that is the mid-point price between the OPA CES price and the non expired NUG price.

2.2.2 OPA Contracts

The OPA has contracts with generators as a result of the Ontario government's or the OPA's request for proposals ("RFPs") for clean ("CES") or renewable ("RES") energy production and demand management measures, and also with a number of other private generators that offer supply into the wholesale market. In general the commodity cost for OPA contracts are modeled on the basis of the contractual agreements. Given that the contract prices are impacted by input costs or other factors there is an assumed price range for these contracts in the analysis. For modeling simplicity, the OPA contracts are grouped in the following commodity categories: Bruce Power, OPA CES, OPA RES, and Standard Offer.

Bruce Power

The cost to customer model specifically identifies the generation from units 1, 2, 3 and 4 as the Bruce A contract. The initial support price for Bruce A is $63/MWh which is comprised of $57.37/MWh for the purchase of power produced by Bruce A LP; and an estimated $6/MWh to cover the costs of fuel. On April 11, 2007, the Minister released a report produced by the Auditor General regarding the Bruce Power Refurbishment Agreement. According to the Auditor General Report, the Refurbishment Agreement indicates a rate of $63/MWh as the initial cost of electricity; however, the trade offs negotiated in the agreement provide additional cash flows to Bruce A LP equivalent to $8.33/MWh. Thus, the all-in cost to ratepayers of the electricity produced by the refurbished units will be closer to $71.33/MWh.[2] After allowing for inflation from 2005 to 2007, for the cost to customer model, the Bruce A price for the medium scenario is assumed to be $74.20/MWh in real terms over the planning period, consistent with the Auditor General Report.

There are many factors that could cause this price to go up, such as cost overruns, staff costs, other materials and services (OM&S), the real cost of fuel, U_3O_8 prices, and etc. To cover all these possibilities the costs have been increased by 10% (to $82/MWh) in the

upper scenario. Cost increases of this magnitude would occur in the unlikely event of cost over runs of about 100%.

The cost to customer model does not have a specific price point for the generation output from Bruce B (units 5, 6, 7 and 8) as the Bruce B, PPA has a recapture payment to obtain the contingent support payments paid out in years when the market price exceeds the floor price of $45.00/MWh. With this clause it is likely that over time the cost a customer will pay for this generation is consistent with the market clearing cost of electricity. Furthermore, the pricing support associated with the floor price for Bruce B is captured in the $71.33/MWh trade off prices established for Bruce A. As a result, for the cost to customer model the generation volume from Bruce B is priced at the market clearing price.

Renewable Energy Supply

The commodity cost for the RES contracts is modeled on the basis of the individual contractual agreements. These RES contracts are predominately fixed price contracts with an inflation index for about 15% of the contract price over time. In the cost to customer model, the price is based on the 2007 weighted average price for the OPA RES contracts of $85/MWh, with 15% of this contract price indexed to CPI.

Clean Energy Supply

The CES contracts are the clean energy supply facilities, such as combined heat and power facilities and combined cycle plant fuelled by natural gas. These contracts are characterized as operating under a deemed dispatch concept whereby the contract is a settlement for differences between the basic investment guarantee and the revenues achieved through market participation. The cost of the CES contracts is based on a forecast of the aggregate of the individual CES contracts. Each contract will vary in cost due to a capacity factor and a gas price input.

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[2] Special Review for the Minister of Energy, The Bruce Power Refurbishment Agreement, Office of the Auditor General of Ontario, page19.

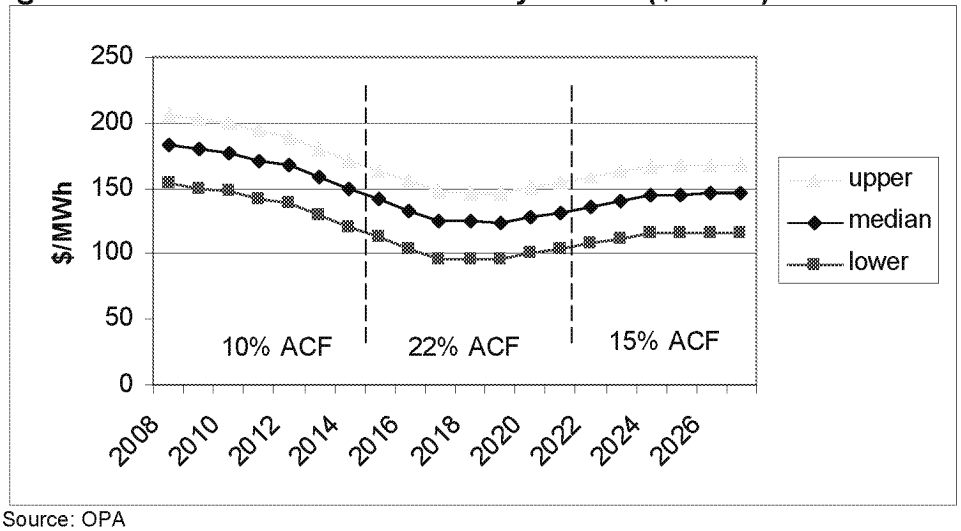
For the cost to customer model, the capacity factor for the combined heat and power facilities, which have host steam load requirements to meet, have been taken as constant over the plan period, while those of the combined cycle plant were varied. Three representative time periods were used, 2008 to 2014, 2015 to 2021, and 2022 to 2027. The average annual forecast ACFs of all combined cycle plant were used. They were 10%, 22% and 15% respectively.

As gas prices are very uncertain, a range of costs was found using Monte Carlo techniques. The same distribution of gas prices was used as was used in the Supply Mix study.

The input gas prices for the facilities are based on a Monte Carlo study on gas prices that was derived in the Supply Mix study. The range of commodity costs was based on the 20th and 80th percentile. These roughly correspond to gas prices of $4/MMBtu and $12/MMBtu.

To avoid discontinuities in the costs in 2015 and 2022, five year rolling averages were used. The resulting high, median and low price scenarios are shown in Figure 2.

Figure 2: Forecast CES Commodity Prices ($/MWh)



Source: OPA

In the event an OPA contract reaches its expiry date during the IPSP planning period, it is assumed that the facility will obtain the market clearing price for its dispatch.

Standard Offer Renewable (Dispatchable /Non-Dispatchable /Solar)

The OPA and the OEB have developed a renewable energy standard offer program for the province designed to encourage and promote greater use of renewable energy sources including wind, waterpower, biomass, and solar, from smaller generating projects that would be connected to an electricity distribution system in Ontario. Standard Offer Program rules currently in place establish the following contract pricing points:

- for the period starting from the program launch to the end of April 30, 2007, all generators with the exception of PV generators are paid a base rate of 11.0 cents per kWh for electricity delivered.
- In the subsequent years, 20% of the base rate is indexed to inflation in the Consumer Price Index.
- Projects that can reliably operate during peak hours are eligible for an additional 3.52 cents per kWh.
- PV projects are paid 42.0 cents per kWh but will not be eligible for inflation indexation or the peak-hour premium.

Since it is not feasible to determine how much energy produced from the Standard Offer generation will be dispatchable, and since it is thought that it will be a small proportion of the total (just some of the biomass output), the cost to customer model groups all the output (with the exception of the Solar PV) and assumes the same price is paid to all units generated. The solar volume is captured in a separate commodity type and allocated the 2008 nominal price of 42 ¢/kWh, which then declines in real terms.

Table 7 below summarizes the costs paid under the contracts in the cost to customer model.

Table 7: Cost to Customer Commodity Costs for "Contract" Generation

	NUGs	Ex NUGs	Bruce A	RES	CES	SO-Non PV	SO - PV
High	117	CES			170		
Median	97	(CES+Mkt)/2	71.33	71	150	90	350
Low	87	Mkt			120		

Source: OPA
Note: Costs are average over the planning period

2.3 Market-Clearing Price (Marginal Cost)

The following generation is assumed to be paid at market clearing prices:

- Bruce B
- !5% of Non-Prescribed Hydro and Fossil generation
- Lennox output[3]
- Non-base load Prescribed Hydro
- Expired CES contracts
- Small renewables

In the cost to customer model, this generation is priced at the annual average marginal cost as calculated by PSM. This estimate assumes no transmission constraints, to be consistent with the IESO's methodology for calculating HOEP.

Table 8: Plan A - Average Annual Marginal Cost

	2010	2015	2020	2025
Average Annual MCP ($/MWh)	35	43	43	38

Source: OPA

In the upper and lower cases these costs are incremented by an arbitrary +$20/MWh and -$10/MWh respectively

[3] The revenue that the Lennox facility receives related to its reliability must run contract is captured in the wholesale ancillary service costs which is a component of the Wholesale Market Charges.

Using the PSM generated marginal prices as a proxy HOEP ignores any bidding strategies that a generator may consider in its bidding into the market that establishes the market-clearing price.

The commodity price in this model also differs from the true market clearing price, as the model uses the demand load at the generator's meter. As a result, the net energy market settlement amount that would normally be collected via a wholesale market service charge is included in the commodity price. In effect, the cost of energy losses of the transmission system associated with the flow of electricity through the transmission lines is captured in the commodity component of the generators.

The imports in the cost to customer model also are based on the market clearing price. The difference in the average annual marginal cost for imports is that this price is based only on the period in which the imports are relied upon. The average import price used in the model, for case A is shown in Table 9 below:

Table 9: Plan A - Average Annual Import Cost ($/MWh)

	2010	2015	2020	2025
Average Annual Import Cost ($/MWh)	33	55	57	69

Source: OPA

2.4 New Generation Units and Refurbishment of Existing Facilities

2.4.1 New Nuclear

For the cost to customer model, the range of new nuclear commodity cost that is used is the result of an analysis of the levelized cost (PPA) including taxes conducted on a range of capital costs for a Candu 6 nuclear facility with a corresponding range of possible financing assumptions. Provided below is a summary of the assumptions utilized to generate the low, medium and high case scenario prices for new nuclear in the cost to customer model.

Table 10: New Nuclear Assumptions

	Low	median	High
Capital cost variation	90%	100%	120%
Return on equity %	9.0%	12%	15%
$/MWh	65	86	110

Source: OPA

The medium PPA resulting for the new nuclear is $86/MWh, which is a supply cost for new nuclear that is slightly above the Bruce A contract.

The low case of $65/MWh and higher case of $110/MWh range for new nuclear is derived by calculating a PPA for discount rates and capital costs independently. The two PPA prices for each independent variable variation for discount rate and capital cost are combined into a single PPA by using the square root rule. The result was then rounded to reflect the imprecise nature of the estimated contract price.

2.4.2 Refurbished Nuclear

It is assumed that refurbishments of existing facilities will obtain a price similar to the existing contract prices for similar types of facilities. This concept of using existing contract prices is viewed to be a reasonable means to estimate the prices necessary for developers to recover the cost of their investments. While this may not be the way generators recover their costs, it is a reasonable way to estimate the impact of new facilities on customer costs in the long term. Furthermore, this methodology is useful in producing sensitivity analysis and trend analysis on the cost to customer amounts.

Generation from refurbished nuclear plants has been priced at the same level of that from the refurbished Bruce A units, in the median case. The upper and lower cases are plus and minus $10/MWh from the mean.

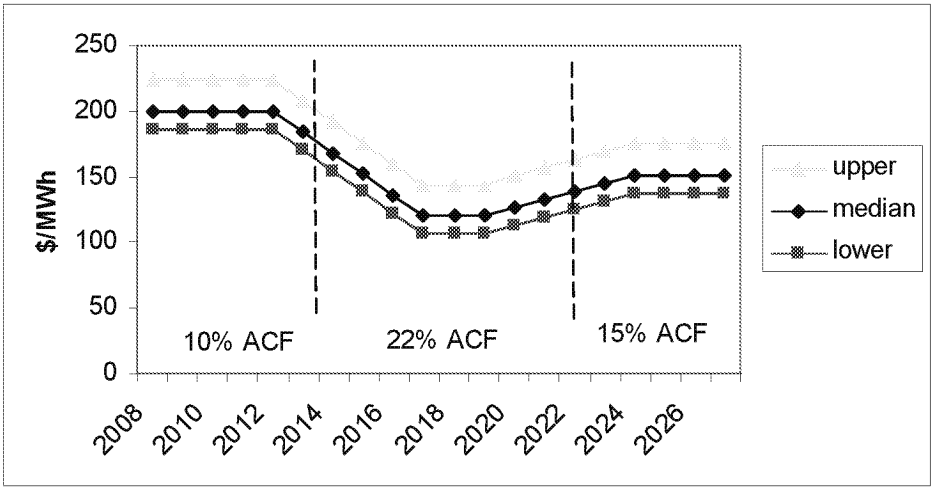
2.4.3 New Gas Fired Generation

The commodity cost for the new gas fired generation is derived on the basis of a PPA analysis similar to that which was done for the new nuclear generation. The analysis

assumes that the new gas facilities will be combined cycle facilities, operating at the same capacity factors as were assumed for the CES analysis. The financial assumptions are consistent with those used in the new nuclear price analysis discussed at section 2.4.1, with the exception that a 70:30 debt/equity ratio was used as opposed to 50/50 for new nuclear.

The major uncertainty associated with a gas plant is the price of fuel. As a result, the input fuel cost associated with the natural gas supply is derived from the Monte Carlo natural gas prices as used in the CES analysis described in section 2.2.2 above. Again the values at the 20 and 80th percentile were used for the upper and the lower cases, and again, five year averaging was used to smooth the discontinuities in year 2015 and 2022 that would otherwise have resulted. The range of commodity costs is shown in Figure 3

Figure 3: New Gas Commodity Price ($/MWh)



Source: OPA

It can be seen that these costs are slightly lower than those predicted from the model of the current OPA CES contracts. However given that some of the new gas will be coming from simple cycle gas turbine plants, which have a lower capital cost, this is seen to be a reasonable range of values to use.

2.4.4 New Renewables

Output from these generators is assumed to be paid at the current RES contract rates ($85/MWh) in the median and lower cases, and 10% higher ($94/MWh) in the upper scenario. The high value is based on assuming that the good sites are already developed and that further technological improvements in wind do not significantly decrease prices.

2.4.5 Beck Tunnel

To capture the cost to customers for OPG's largest capital project, the Niagara Tunnel which will divert more water to the Beck hydroelectric complex to provide the station with the capability to generate the additional 1.6 billion kilowatt hours of renewable hydroelectricity for Ontario, a new commodity type entitled Beck Tunnel is included in the commodity section of the cost model. According to OPG's 2006 Annual Report, the completion of this project will be in late 2009 with a projected cost of approximately $985 million. Assuming a cost recovery for this capital build and a real rate of return of 10%, the unit price for this Beck Tunnel in the cost to customer model is $69 per MWh. The $69 per MWh price for the Beck Tunnel is assumed for the medium, high and low case scenario.

3.0 CONSERVATION COSTS

Previously, the costs associated with Conservation programs were recovered from customers by way of increased distribution costs from the electrical Local Distribution Companies ("LDCs"). On May 31, 2004, the Minister of Energy encouraged LDCs to submit plans to the OEB for $163 million worth of Conservation projects to be initiated over a three year period. LDCs were required to obtain the funding of the Conservation projects from the OEB by way of their third installment ("tranche") of incremental Market Adjusted Revenue Requirement ("MARR"). This third tranche funding is expected to end as of September 30, 2007.

The OPA has received a number of directives from the Minister of Energy to undertake Conservation programs including a directive to assume responsibility for the coordination and funding of the delivery of Conservation programs by local distribution companies in Ontario. The funding under this directive is limited to $400 million over three years. The costs for OPA Conservation programs and initiatives, inclusive of incentive payments for customers to curtail consumption, will be recovered from customers in the commodity rate via the Global Adjustment Mechanism.

In the IPSP analysis Conservation costs are identified as a separate cost component in order to provide greater transparency in the cost to customer analysis. The basic assumption about Conservation costs is that the program and incentive cost related to Conservation will be recovered by customers as an additional volumetric rate required from Ontario consumers. The Conservation program costs and incentive payments used in the cost to customer model are found in Exhibit D-4-1. Included in the Conservation program and incentive costs is the OPA direct operating costs related to Conservation programs and initiatives of approximately $26.5 million in 2008. In order, to avoid double counting the wholesale charge for OPA administration rate is reduced by this corresponding amount.

4.0 TRANSMISSION COSTS

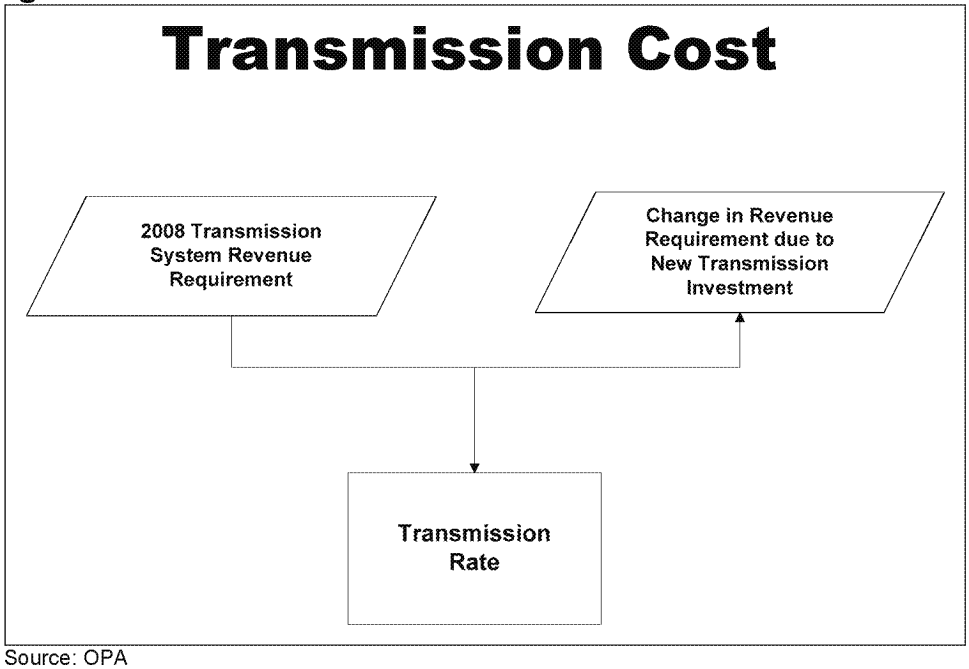
The infrastructure of high-voltage transformers and lines that deliver the electricity from the generating stations to the consuming regions is the transmission system. The transmission system is a high voltage system that operates at 500 kV, 345 kV, 230 kV, 115 kV and 69 kV, and is designed to transmit electricity from directly connected generation to LDCs and end-use transmission customers. The transmission system interconnects the facilities of neighbouring provinces and states, specifically Manitoba, Québec, Minnesota, Michigan and New York, to enable the transfer of electrical energy between Ontario and these jurisdictions.

The Ontario transmission system is owned by the following transmission companies: Hydro One, Great Lakes Power, Canadian Niagara Power, and Five Nations Energy, with Hydro

One accounting for 96.3 percent of the total transmission revenue requirement for the province. The remaining 3.7 percent of the cost of transmission for the province of Ontario is as follows: Great Lakes Power is 2.9 percent, Canadian Niagara Power is 0.4 percent, and Five Nations Energy is 0.4 percent.

The methodology to capture the transmission cost in the cost to customer model is to take a base cost of transmission and layer on the incremental revenue requirement associated with additional incremental capital and operating and maintenance ("O&M") costs for new network and enabler facilities assumed to be added during the planning period. An illustration of these two major cost components used to generate the transmission costs for the cost to customer model is provided in Figure 4.

Figure 4: Transmission Cost Schematic



Source: OPA

The cost associated with the transmission infrastructure is recovered from the customers of Ontario through transmission charges approved by the Ontario Energy Board. On

September 12, 2006, Hydro One made its initial application to the Ontario Energy Board for approval of a revenue requirement. Subsequently to filing, on February 23, 2007, Hydro One filed an update to this revenue requirement seeking approval for $1,261 million and $1,287 million for 2007 and 2008, respectively. This transmission rate application by the largest transmission company in Ontario comprises a significant portion of the base transmission assumptions for the cost to customer model.

The 2008 base transmission is assumed to be $1,331.6 million which is made up of Hydro One's revenue requirement of $1.287 million and the revenue requirements for other remaining transmission facilities: Great Lakes Power ($34.8 million), Canadian Niagara Power ($4.6 million), and Five Nations Energy ($5.2 million).[4] This base 2008 revenue requirement of $1,331.6 million is converted into $2007 dollars of $1,305.4 million and assumed be constant in real terms throughout the IPSP planning period.

The revenue requirement for any new transmission expansion associated with the IPSP is layered on top of the base revenue requirement to capture the incremental transmission costs of the new facilities. The financial assumptions of the debt/equity ratio, cost of debt and return on equity for the new transmission facilities are consistent with those found in the Hydro One Transmission Application (EB-2006-0501) submission.

5.0 WHOLESALE MARKET CHARGES

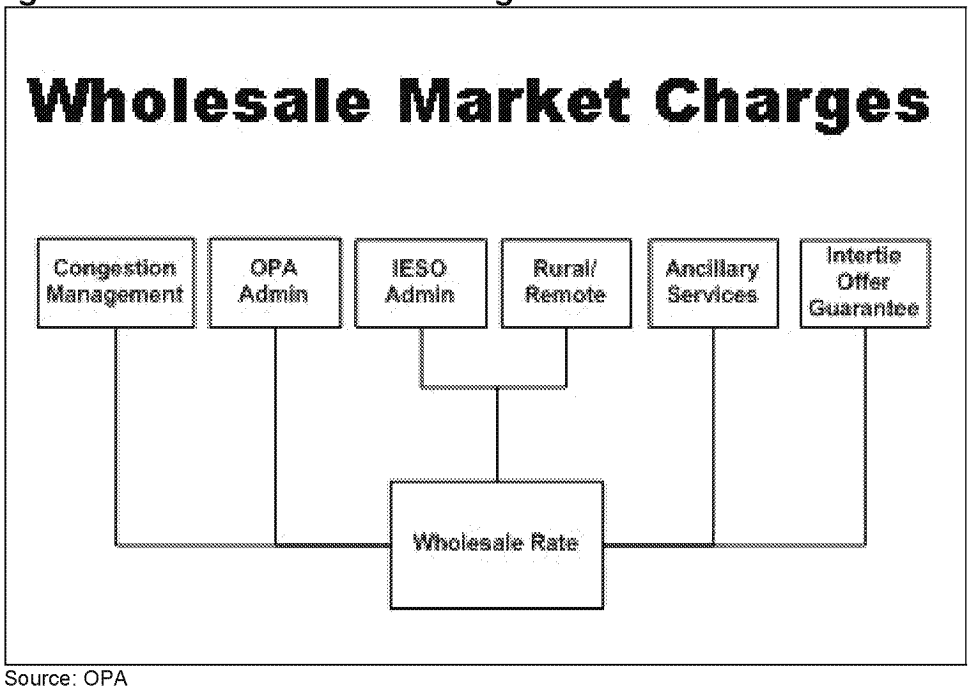
The wholesale market charges cover the cost of service that is essential for operating the electricity system and running the electricity market. The list of charges in this category that the IESO flows through to customers is extensive and variable in nature. A comprehensive list of wholesale charge types is provided at the following IESO link:

http://www.ieso.ca/imoweb/pubs/settlements/IMO_Charge_Types_and_Equations.pdf.

[4] The revenue requirements for Great Lakes Power Limited (GLPL), Canadian Niagara Power (CNPI), and Five Nations Energy Inc (FNEI) is obtained from an interrogatory response to the OEB as filed by Hydro One Networks in the EB-2006-0501 proceeding (Exhibit J, Tab 1, Schedule 169).

The cost to customer model breaks down the wholesale charges it needs to recover into the following major charge components as shown in Figure 5.

Figure 5: Wholesale Market Charges Schematic



Source: OPA

A discussion of each of these wholesale charge components follows.

5.1 Congestion Management Settlement Uplift

The market clearing price for Ontario is determined by using an ideal system where there are no physical limitations on the transmission of power. However, the physical system prevents this ideal dispatch from being realized, as there may be capacity constraints on the lines.

In order to preserve the integrity of the power grid, the IESO's dispatch instructions must take these constraints on the transmission lines into account. When there are constraints on the lines (congestion), actual dispatch instructions may be different from what we would expect, but the market clearing price does not change. However, in order to maintain

fairness in the market, generators and loads are paid 'constrained-on' and 'constrained-off' payments if they are affected by transmission line limitations.

As the constraints arise from a variety of operational issues it is not possible to forecast them with any degree of accuracy. For the cost to customer models the 2006 levels of payments have been assumed to continue throughout the planning period of the IPSP.

5.2 Ontario Power Authority Administration Rate

The OPA charges its expenses associated with carrying out its legislative and directive-related mandates for long-term planning, capacity procurement, conservation initiatives, and market evolution to customers through its revenue requirement application. This revenue requirement is submitted to the Ontario Energy Board for approval and recovery from customers.

For the cost to customer model, the OPA's 2008 revenue requirement is estimated at $68 million, which reflects the most recently available estimate for the 2008 Budget. This 2008 revenue requirement budget estimate of $68 million includes the direct operating costs related to the OPA's Conservation programs and initiatives of $26.5 million, which has already been captured in the Conservation costs above. In order to avoid double counting, the OPA Administration Rate is derived from $41.5 million (which is $68 million less $26.5 million). For the cost model the OPA Administration unit rate of $0.265/MWh is held constant in real terms for the IPSP period.

5.3 Independent Electricity System Operator Administration Rate

The IESO charges administrative costs to operate the wholesale electricity market and electricity power system in Ontario. This revenue requirement is approved by the Ontario Energy Board.

In the IESO's 2007 to 2009 Business Plan, the 2007 usage fee requirement is $133.3 million. For the cost to customer model this amount is translated into a unit rate of

$0.80/MWh and is held constant in real terms, to generate the IESO administration cost to be recovered from the customer.

5.4 Rural/Remote Settlement Rate

The Rural or Remote Electricity Rate Protection rate is used to partially offset the higher costs of providing electricity in rural/remote areas. This rate is fixed at 0.1 cents/kWh and is established by regulation. For the cost to customer model this rate has been held constant in nominal terms for the planning period of the IPSP, as historically this rate has not changed since its inception at market opening.

5.5 Ancillary Services

In order to ensure the reliable operation of the power system, the IESO contracts for a number of ancillary services. The ancillary services include the operating reserves, black start capability, regulation services as well as reactive support and voltage control. The operating reserve service is associated with stand-by power required in case of an unexpected reduction in power supplied from a generator. Black start capability is a generator's ability to help restore the province's power system in the case of emergency. The regulation service represents the ability of a generator to control its generation output on a second-by-second basis so that the IESO can adjust imbalances between load and generation by using the generator's automatic generation control ("AGC") capacity. The reactive support and voltage control service is a service provided by generators that allows the IESO to maintain consistent reactive power and voltage levels on the grid. These rates and charges vary by the hour.

The 2006 historical year cost for ancillary services was converted into a unit cost and indexed to the rate change for the TMC as ancillary services are "joint products of energy" and as such their escalation is likely to be tied to the change in cost for energy.

Embedded in the 2006 unit rate for ancillary service is the cost for the Lennox reliability must run contract of $60 million.

5.6 Intertie Offer Guarantee ("IOG")

The Ontario energy market has been designed to allow market participants to import power from and export power to other jurisdictions. As the source (or destination in the case of exports) is outside the Ontario control area, imports and exports cannot be dealt with in the same way as internal supply and demand. Import and exports are scheduled an hour in advance which means that an import that is to take place between 11:00 to 12:00 will be locked in shortly after 10:00, during the hour-ahead pre-dispatch run of the scheduling algorithm. In the event, the energy from the import or export cannot flow, or if the Ontario price is different, there is an extra price risk to the importer and exporter.

Given this risk to the imports and the need to ensure adequacy of supply to Ontario, the IESO offers an IOG payment to reduce the price risk to imports. This IOG payment ensures that over the course of the hour an importer will receive at least the accepted offer price and will not suffer a negative impact if the real-time inter-tie zone price is lower.

For the cost to customer model, the 2006 historical unit rate has been adopted for the IPSP planning period and held constant in real terms.

The following figure summarizes the assumptions for the various wholesale market charges used in the cost to customer model:

Table 11: Summary of Wholesale Market Services assumptions

Charge	Assumption
Congestion Management Settlement Uplift	2006 Congestion Payments
OPA Administration rate	2008 OPA estimate less conservation related costs
IESO Administration Rate	2007 IESO unit rate
Rural / Remote Settlement rate	2007 OEB rate (nominal rate charge)
Auxiliary Services	2006 unit rate (change based on TMC)
IOG	2006 rate

Source: OPA

6.0 DEBT RETIREMENT CHARGE ("DRC")

The Act imposes a charge, known as the Debt Retirement Charge which is payable on electricity consumed in Ontario. The DRC is a 0.7 cents per kilowatt hour charge for electricity consumed in most Ontario communities.

All revenues from DRC will be used exclusively to pay down the residual stranded debt of the former Ontario Hydro. In the cost to customer model the DRC rate of 0.7 cents/kWh rate is fixed in nominal terms from 2008 to 2020. By 2021, the DRC is projected to end, as the residual stranded debt is expected to be extinguished.

7.0 DISTRIBUTION COSTS

The distribution cost is the cost for delivering electricity from the transmission system to an end-user's location such as a home. The distribution system is the portion of the electricity system infrastructure at a voltage level below 50 kilovolts that delivers the electricity to lower voltage users such as homeowners, apartments, and local commercial and industrial sites.

Currently, there are over 90 electricity distributors in Ontario that are regulated by the OEB. The methodology of capturing the distribution cost in the cost to customer model is to take the total revenue of all LDCs, in 2006, which was approximately $2.75 billion plus the additional capital cost for the smart meters implementation, to generate a unit cost per household. The distribution cost is assumed to be equal to the constant real term unit rate per household for the term of the plan. The methodology is based on recognizing the fact that distribution costs are largely driven by the cost of the infrastructure, and is much less dependant on usage.

The forecast of household starts that has been used is shown below. It is consistent with the load forecast.

Table 12: Housing Stock

	2005	2010	2015	2020	2025
Housing Stock (000s)	4960	5310	5640	5960	6300

Source: OPA

For the upper scenario, distribution costs have been increased by a further 1% per year, in recognition that there is a substantial requirement to replace aging infrastructure, which together with increasing demands for under grounding facilities could put further upward pressure on costs. This 1% figure has not been substantiated by any studies.

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CONSIDERATION OF SAFETY, ENVIRONMENTAL PROTECTION AND ENVIRONMENTAL SUSTAINABILITY

1.0 INTRODUCTION

This exhibit describes how the OPA considered safety, environmental protection and environmental sustainability in its development of the Integrated Power System Plan (IPSP or the "Plan"). It focuses on electricity resources at the plan level.

2.0 OVERVIEW

Subsection 2(1), paragraph 7 of Ontario Regulation ("O. Reg.") 424/04 requires the OPA to "ensure that safety, environmental protection and environmental sustainability are considered in the plan". The OPA considered these factors in the following way:

- Environmental sustainability was a central component to the development of the OPA's planning criteria; this is described in Exhibit B-3-1;
- Specific environmental data for generation and transmission resource alternatives in support of the Plan were developed by SENES Consultants Limited ("SENES")[1]. The OPA commissioned an independent peer review of the SENES report, which found that a good range and number of references and information sources are considered and utilized within the report.[2] These data have been used by the OPA to conduct the analysis of the IPSP resources;
- The OPA undertook an analysis of the environmental impact of those projects that met the criteria in subsection 2(1), paragraph 8 of O. Reg. 424/04, and alternatives to those projects; this is described in more detail in Exhibit E-2-1.

With respect to safety in particular, the OEB's Filing Guidelines state that the OPA should, in developing the IPSP, use the following definition for safety:

> *Safety*
>
> Refers to the safety of workers and members of the public through compliance with all applicable Ontario and federal laws and regulations pertaining to the construction and operation of facilities identified in the IPSP, including regulations and

[1] See Attachment 1 to this exhibit.
[2] See Attachment 2 to this exhibit.

requirements of the Electrical Safety Authority and of the Canadian Nuclear Safety Commission.

The OPA notes that equipment used in specific supply and transmission facilities and the construction and operation of these facilities are subject to a range of safety and environmental requirements. The risks to worker and public safety, and the environment associated with activities related to the generation, transmission and use of electricity are regulated through licensing processes and specific measures established by numerous organizations with legal mandates to ensure safety and environmental protection. The OPA looks to these organizations to manage risks to safety and the environment arising from any planned facility.

A list of agencies and organizations with a mandate to ensure safety and environmental protection with respect to electricity sector development and operations is included in Appendix A to this exhibit.

In addition, environmental considerations with respect to individual electricity resources in the Plan are addressed at the project-specific level. New generation and transmission projects identified for implementation in the IPSP will require specific approvals under the Ontario *Environmental Assessment Act* (the "EA Act"). These facilities may also be subject to additional federal, provincial or municipal approvals. Nuclear projects, including new and refurbishment of existing facilities, are subject to a federal environmental assessment process under the *Canadian Environmental Assessment Act* and approval and licensing by the Canadian Nuclear Safety Commission ("CNSC"). Detailed considerations of environmental impacts at local and regional levels are addressed during project level assessments and approvals.

3.0 DESCRIPTION OF ANALYSIS

This analysis focuses on a set of environmental indicators relevant to resources included in the IPSP. Furthermore, the indicators are applied to test the robustness of the Plan using scenarios. The sensitivity analysis helps highlight the impact on the indicators as they

relate to air, water and land use depending on variations in the resource mix or uncertain variables.

The OPA's quantification of environmental indicators provides directional indication of impacts and helps define the scope or terms of reference for project level environmental assessments. The indicators are intended to show positive or negative trends. A consistent consideration of the key long-term environmental effects of the Plan can provide guidance to subsequent planning processes. Early consideration of potential long-term impacts are identified at the Plan level to ensure flexibility in the selection and timing of specific projects. This information can also serve to highlight future initiatives that may help reduce and mitigate foreseeable environmental impacts.

The analysis considers the electricity supply and transmission options in the IPSP. Reduction of energy use through Conservation is considered a positive attribute of the Plan and, thus, environmental impacts of Conservation are not considered further in this analysis.

The assessment undertaken by the OPA has focused on emissions related to the operations phase of generating facilities because this phase has the dominant impacts and data relevant to the Ontario-specific context for generation facilities are available. Six environmental indicators have been selected based on the evaluation criteria developed by SENES:

- Greenhouse gas emissions;
- Air contaminant emissions;
- Radioactivity;
- Water use (consumptive and non-consumptive);
- Solid wastes; and
- Land use.

Environmental externalities[3] have been addressed in accordance with the OEB Filing Guidelines as part of the OPA's analysis. The tracking of the Plan against these selected indicators addresses the significant environmental externalities, quantitatively and in a consistent manner for all resources included in the Plan. The indicators described below are intended to be considered as part of the broader framework of sustainability that has been developed as discussed in Exhibit B-3-1.

3.1 Environmental Indicators

A summary of the steps involved in developing the environmental indicators is as follows.

Step one: For each resource option, collect the relevant environmental data for the indicator to be used in the analysis.[4]

Step two: Quantify the environmental indicators for the aggregated supply and transmission resources at specific time intervals in the IPSP. In this step, the environmental indicators are quantified for the Plan using the OPA's Portfolio Simulation Model (PSM) as described more fully in Exhibit G-2-1.

Step three: Evaluate and compare the results of the reference Plan and additional scenarios, where feasible. This step involves interpretation of results.

This information can be useful in identifying potential issues early in the project planning stage and help guide development of Terms of Reference for an environmental assessment ("EA") or screening of a specific facility. The six selected indicators are shown as trends describing the Plan over its 20 year horizon.

3.2 Environmental Indicators

All forms of electricity generation and transmission are associated with some effects on the environment. The energy sources from which electricity is derived are extracted or

[3] Environmental externalities are environmental costs, such as those associated with air emissions that are not reflected fully in the cost of electricity.
[4] This step was completed by SENES Consultants Ltd.

harnessed from nature (wind, water, solar) and resulting emissions and waste products are either assimilated back into the environment or require long-term management. Accordingly, the OPA has placed a high degree of importance on understanding those aspects of the IPSP that provide some insights about potential impacts on the environment.

Environmental indicators, as shown in Table 1, are quantified at the Plan level.[5] The indicators are described in further detail in Appendix B. In developing the Plan, emphasis has been placed on tracking significant indicators that capture directional trends. The quantities tracked are indicators of the extent to which the future electricity system may cause adverse environmental effects. Collectively, these environmental indicators capture the likely impacts on three important environmental media – air, water and land. Environmental considerations of the Plan can be judged as satisfactory if trends over time are stable or declining.

At the project level, all the emissions and resource uses are subject to specific regulatory limits and oversight. Project developers and operators are regulated and monitored by agencies with a clear mandate for specific compliance. The OPA takes into consideration this comprehensive governance capability for managing environmental protection in the Plan's development.

[5] Quantification of various environmental emissions provides an indication of the magnitude of the effect and allows guidance to be developed for judging the relative impact on the environmental performance of the overall plan amongst different resource options. OPA has not monetized the emissions given lack of relevant data for application in the Ontario specific context. OPA assumes proponents will develop resources and construct and operate facilities that will fully comply with of all environmental, health and safety regulations. Effects related to specific emissions are controlled and managed through applicable regulations and compliance limits. Absent a specific regulation for an emission (e.g., GHGs), further development of policy instruments such as emissions cap and trade systems or taxes to address environmental externalities would be necessary.

Table 1: Environmental Indicators

Indicator	Description
Greenhouse Gas Emissions	Three primary GHGs (CO_2, CH_4 and N_2O) are quantified for electricity resources in the Plan Sulphur hexafluoride (SF_6) emissions are also considered
Air Contaminant Emissions	Four air contaminants are quantified for electricity resources in the Plan (NO_x, SO_2, $PM_{2.5}$ and mercury)
Radioactivity	Public exposure to radionuclide emissions to air and water are considered
Water Use	Water consumption and flow-through water (non-consumptive) are quantified for electricity resources in the Plan
Solid Wastes	Solid wastes are quantified and broken down according to the type and quantity
Land Use[1]	Total physical area of land disturbance is quantified for all electricity resources in the Plan Some consideration is given to land that would remain available for other uses

Source: SENES Consultants Limited

Notes: [1] The land use indicator is also considered in the context of societal acceptance

A balance is achieved by this set of indicators, between information that is available and information that provides an indication of the extent to which the future electricity system may cause adverse environmental effects. Collectively, the six indicators capture likely impacts on three important environmental media – air, land and water.

Since the initial work was performed in November 2006, the OPA has worked with its consultant to revise the data to better reflect the types of power plants that would be built in Ontario. The data used to describe the environmental attributes of electricity resource options draws upon publicly reported and available information to the greatest extent possible. An overview of the specific indicators is provided in Appendix B and further details are provided in SENES (2007)[6].

3.3 Results

The share of electricity generated by each resource within the Plan is estimated using the PSM simulation model. Each environmental indicator is quantified and the results expressed on an absolute basis (e.g., in terms of total tonnes of pollutant per year).[7]

[6] See Attachment 1 to this exhibit.

[7] In the case of the land use indicator, environmental performance is expressed in terms of total area that is claimed at one time during the period of the Plan.

The Plan results are summarized in the following subsections for each environmental indicator. The results are shown for two sets of reference conditions: one which assumes the Pickering B nuclear station undergoes refurbishment (Case 1A) and the other assumes that the Pickering B plant is not refurbished (Case 1B). In addition, the environmental indicators are described for three potential circumstances that test the robustness of the Plan. The two cases, A and B, are also shown for the following circumstances:

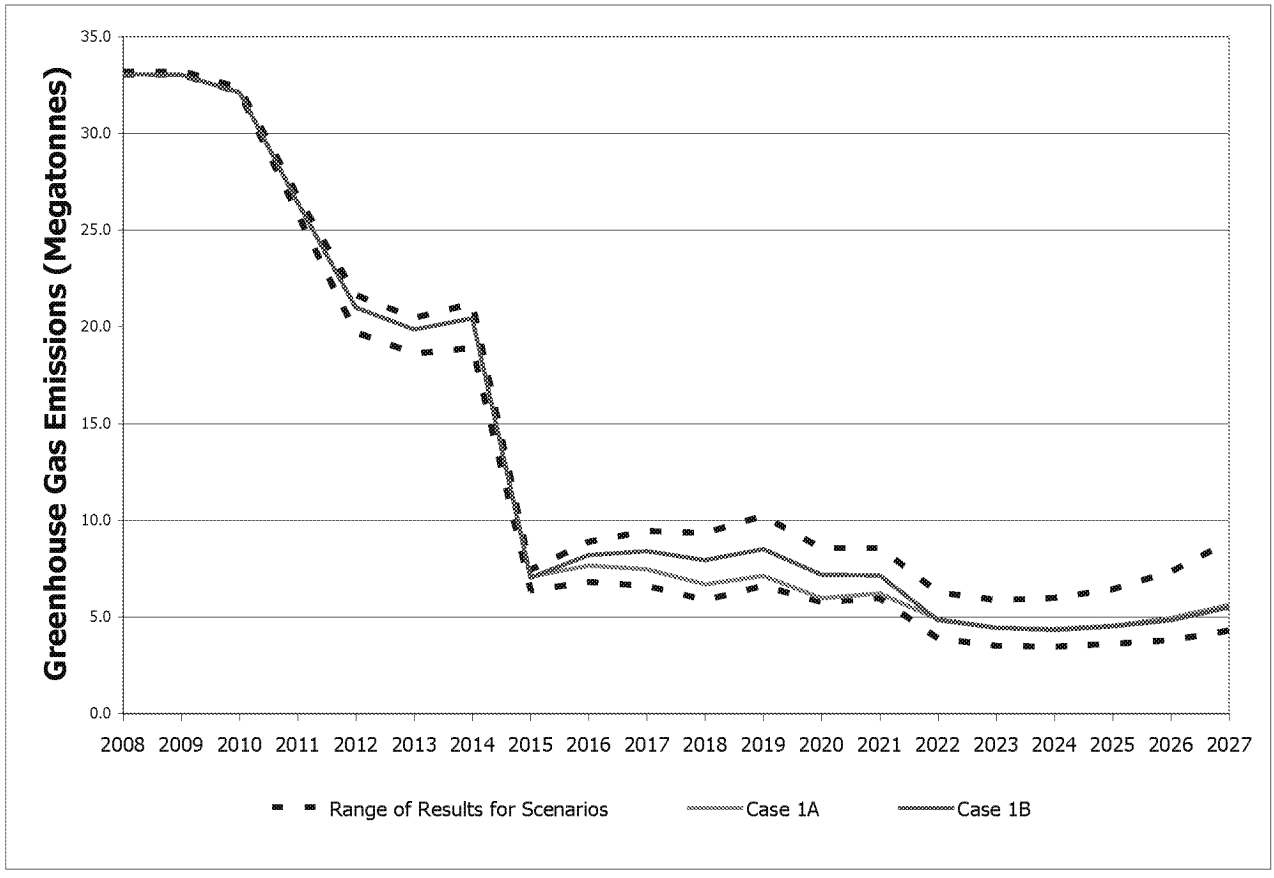
- Case 2: higher demand growth ("high demand")
- Case 3: greater success in capturing conservation potential ("high conservation")
- Case 4: major transmission required for incorporation of northern renewables is not implemented ("no North-South Tie")

All of the cases referenced above are described in more detail in Exhibit G-1-1. The results considered on a year by year basis over the 20 year IPSP period are described further in the following subsections.

Greenhouse Gas Emissions

This indicator considers emissions of three main greenhouse gases (GHGs): carbon dioxide (CO_2), methane (CH_4) and nitrous oxide (N_20). GHGs from Ontario's electricity sector are expected to decrease substantially over the Plan period from a level of 33.1 megatonnes (MT) in 2008 to approximately 5.6 MT in 2027 for the reference Plan (Case 1A). The GHG emissions in the scenarios range from 4.3 to 8.9 MT at 2027. In all cases, a large decrease in the near-term GHG emissions directly results from the phase-out of coal fired power. Coal plants have GHG emission intensity that is over three times that of combined cycle gas. Emissions of GHGs for Cases 1A and 1B are illustrated in Figure 1, with the results from all the scenarios illustrated as the minimum and maximum range conditions.

Figure 1: Summary of Greenhouse Gas Emissions



Source: OPA

Following a significant short-term reduction, in the medium term, GHG emissions rise slightly and decrease again over the 2016 to 2022 period. This interim increase is due to the increased energy output from combined cycle gas turbines, which play an important role in the resource mix during the period of nuclear refurbishments and the building of capacity in new renewables and conservation. Increased nuclear production, new renewables and Conservation in the period following 2021 lead to further reductions in GHG emissions. The interim rise in GHG emissions is slightly higher in the case of no Pickering B refurbishment (Case 1B). Both cases result in similar levels of GHG emissions

at 2027, which are approximately 78% below the 1990 baseline year, when emissions from fossil-fuelled generation in Ontario were at 26 MT.[8]

In addition to the three gases captured in the GHG indicator, there will be a minor increase in the use of sulphur hexafluoride (SF_6)[9] related to planned facilities: one new transformer station (with third generation GIS equipment) is included in the Plan at the Hearn site (Portlands) and expansion of the Milton transformer station would result in a marginal increase in the amount of SF_6 used. All new switchgear planned in the IPSP will also use SF_6 as the insulating gas, but this gas would remain sealed in the equipment. Overall, the total impacts related to the potential of SF_6 in the IPSP are negligible because emissions are expected to be low.

Air Contaminant Emissions

Emissions of all four air contaminants are expected to decrease substantially over the Plan period. The decrease is a direct result of the phase-out of coal fired power. Similar to GHGs, these reductions are predictable given that coal has the highest emissions intensity for all air contaminants. The trends for all four contaminant air emissions are similar. Emissions of nitrogen oxides (NO_x) are shown in Figure 2, fine particulate material ($PM_{2.5}$) emissions in Figure 3, sulphur dioxide (SO_2) emissions in Figure 4, and mercury in Figure 5. The results illustrated in these figures include Case 1A and Case 1B as well as the minimum and maximum values for the scenarios.

Following the coal phase-out and corresponding decrease in air emissions, NO_x and $PM_{2.5}$ display a marginal increase in the medium-term period (2015 to 2022) before declining again in the long term when additional conservation, nuclear and new renewables are

[8] Greenhouse gas emissions for the 1990 baseline year were supplied by Ontario Power Generation's Sustainable Development Group.

[9] Sulphur hexafluoride (SF_6) is a powerful GHG used as an insulating gas in electrical equipment. It has a global warming potential that is 23,900 times that of CO_2. Some SF_6 is emitted during installation, service and disposal of equipment such as circuit breakers and gas-insulated switchgear (GIS) substations. When gas is required to be evacuated from breakers or gas compartments, it is captured and held in gas containers before being returned to equipment or returned for processing to suppliers. For second generation GIS equipment (e.g., at Claireville transformer station) the manufacturer's specifications call for 0.5% of gas (by mass) to

operating. For Case 1B, the interim increase in emissions is slightly more pronounced for both NO_x and $PM_{2.5}$.

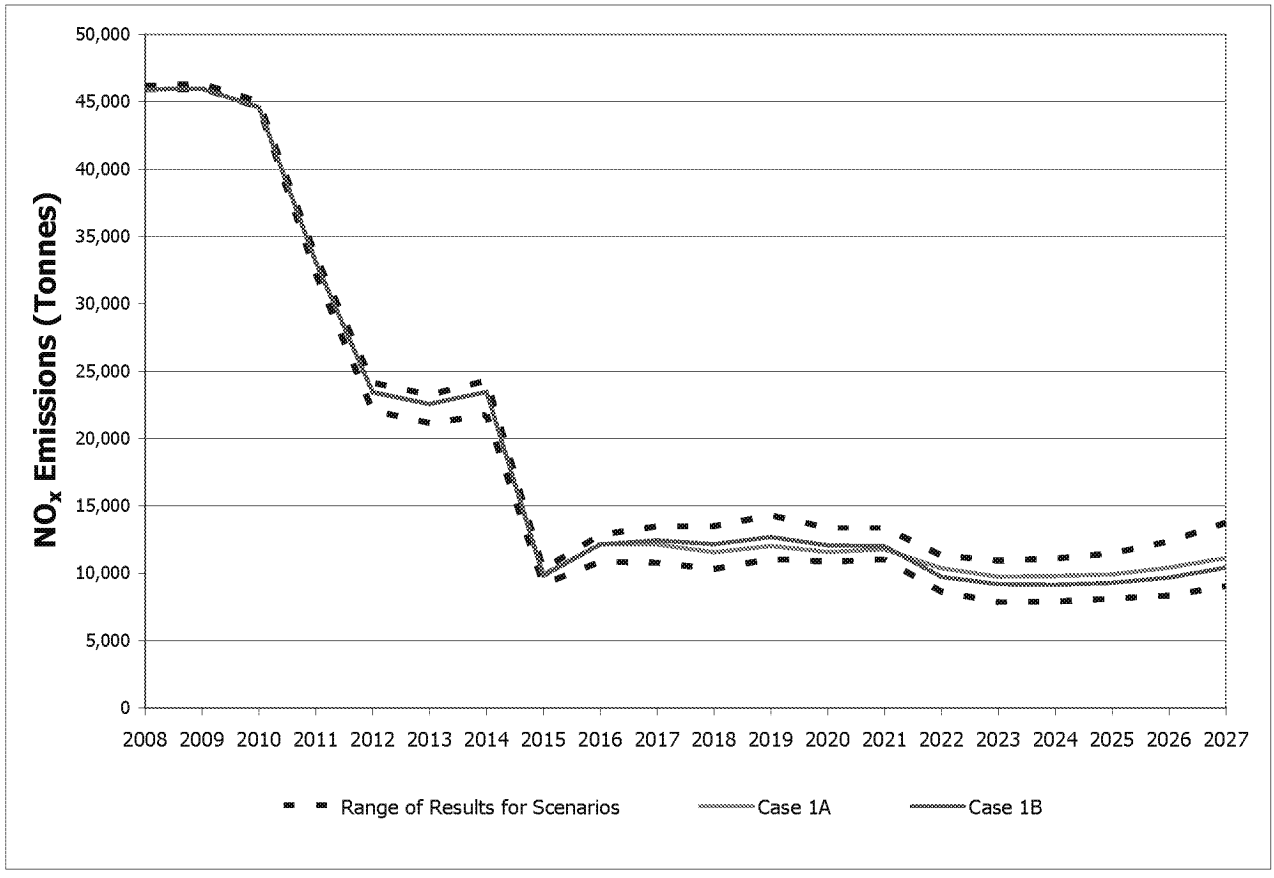
Emissions of NO_x in 2027 are 76%, and 77% less than those in 2008 for Case 1A and Case 1B, respectively. Emissions of $PM_{2.5}$ decrease by 69% for Case 1A and 71% for Case 1B, respectively, in 2027 compared to 2008. The results for $PM_{2.5}$ illustrated in Figure 3 are shown as an upper-bound estimate for the Plan because emissions rates for PM_{10} particles are used as a proxy.[10] This provides a conservative estimate of fine particulate material emissions and ensures that these are not underestimated in the analysis.

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be lost per gas compartment. Third generation GIS equipment (e.g., Bowmanville switching station) calls for 0.1% of gas (by mass) to be lost per gas compartment. Similar information would be found on vendor specifications for gas loss in SF_6 breakers.

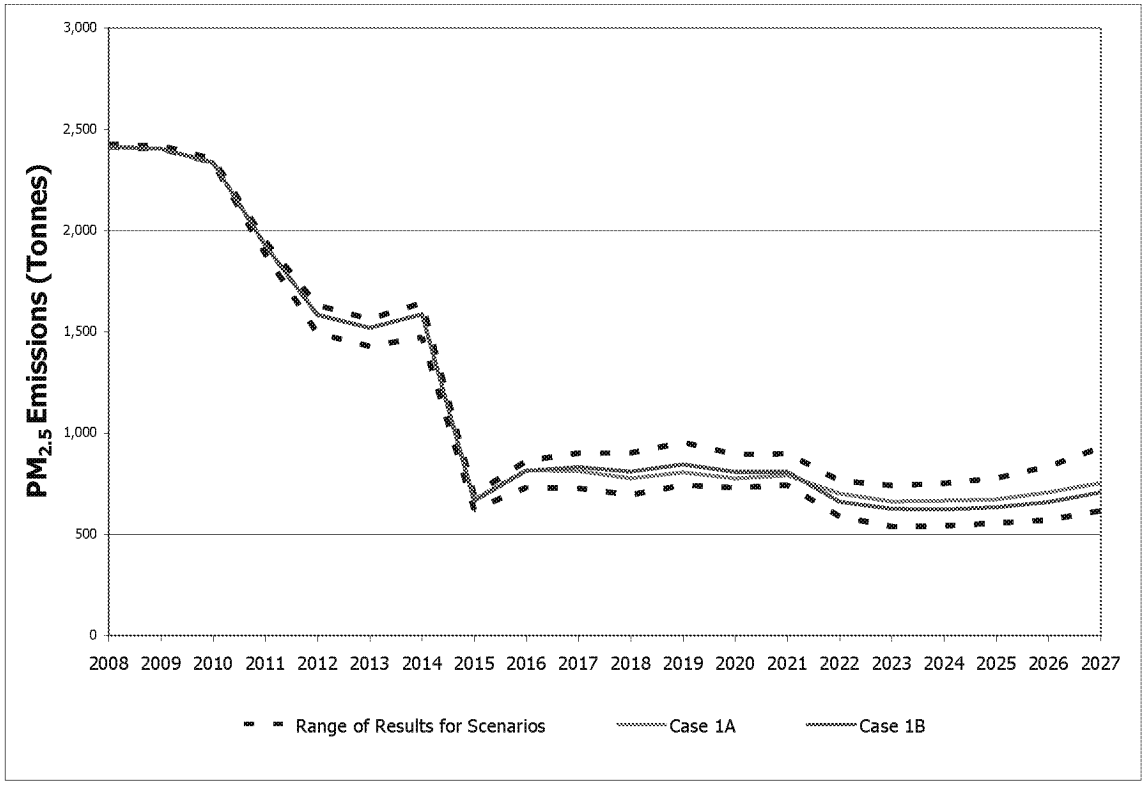
[10] Detailed information regarding $PM_{2.5}$ emissions for all generating resources is not currently available at the plant-specific level. The PM_{10} range includes all particles with effective diameters less than 2.5 microns and would thus result in an estimate that is conservatively high for the $PM_{2.5}$ range.

Figure 2: Summary of Nitrogen Oxide Emissions



Source: OPA

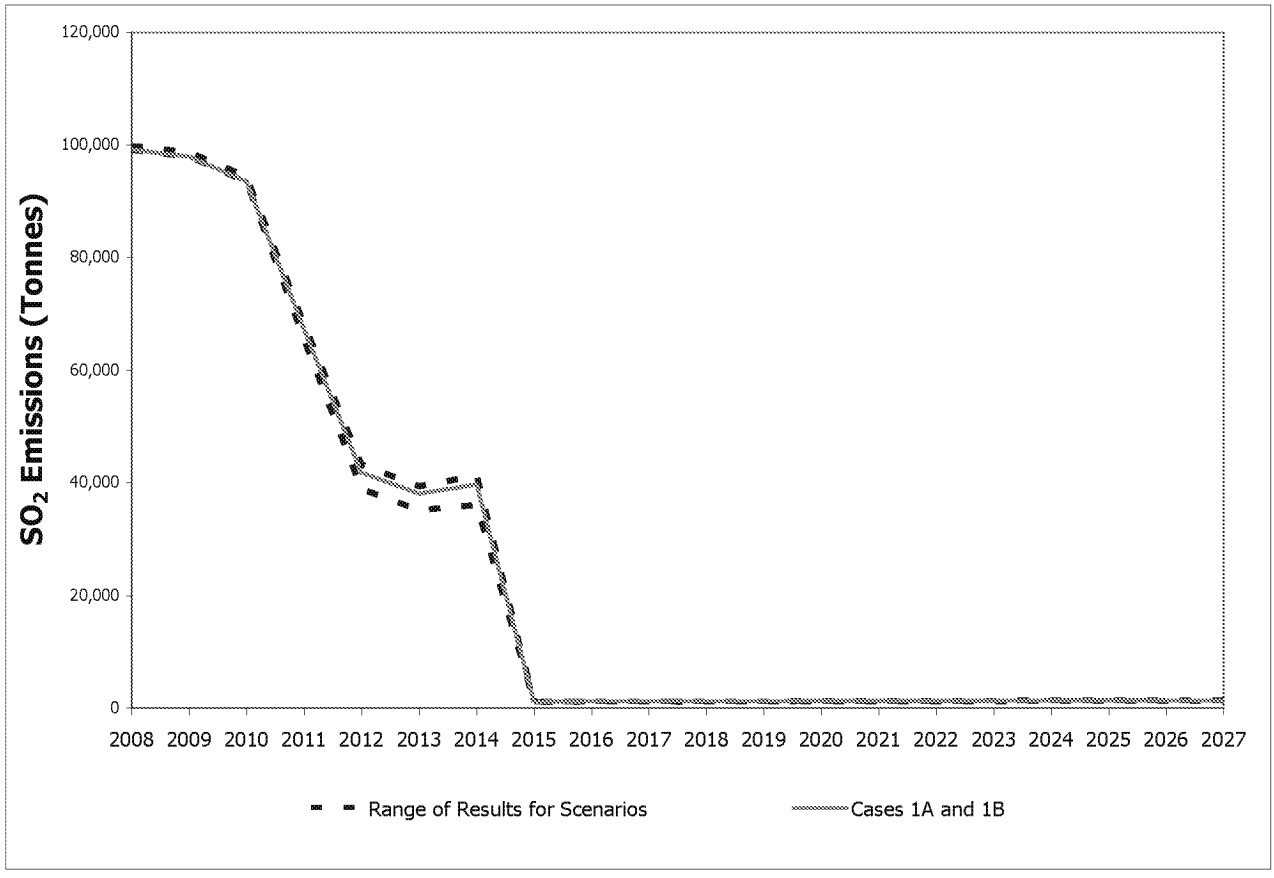
Figure 3: Summary of Particulate Material Emissions



Source: OPA

As shown in Figure 4, emissions of SO_2 remain at very low levels following the phase-out of coal because these emissions are not associated with other forms of generation in appreciable quantities. Emissions of SO_2 are the same for both cases and do not vary significantly whether or not the Pickering B plant is refurbished.

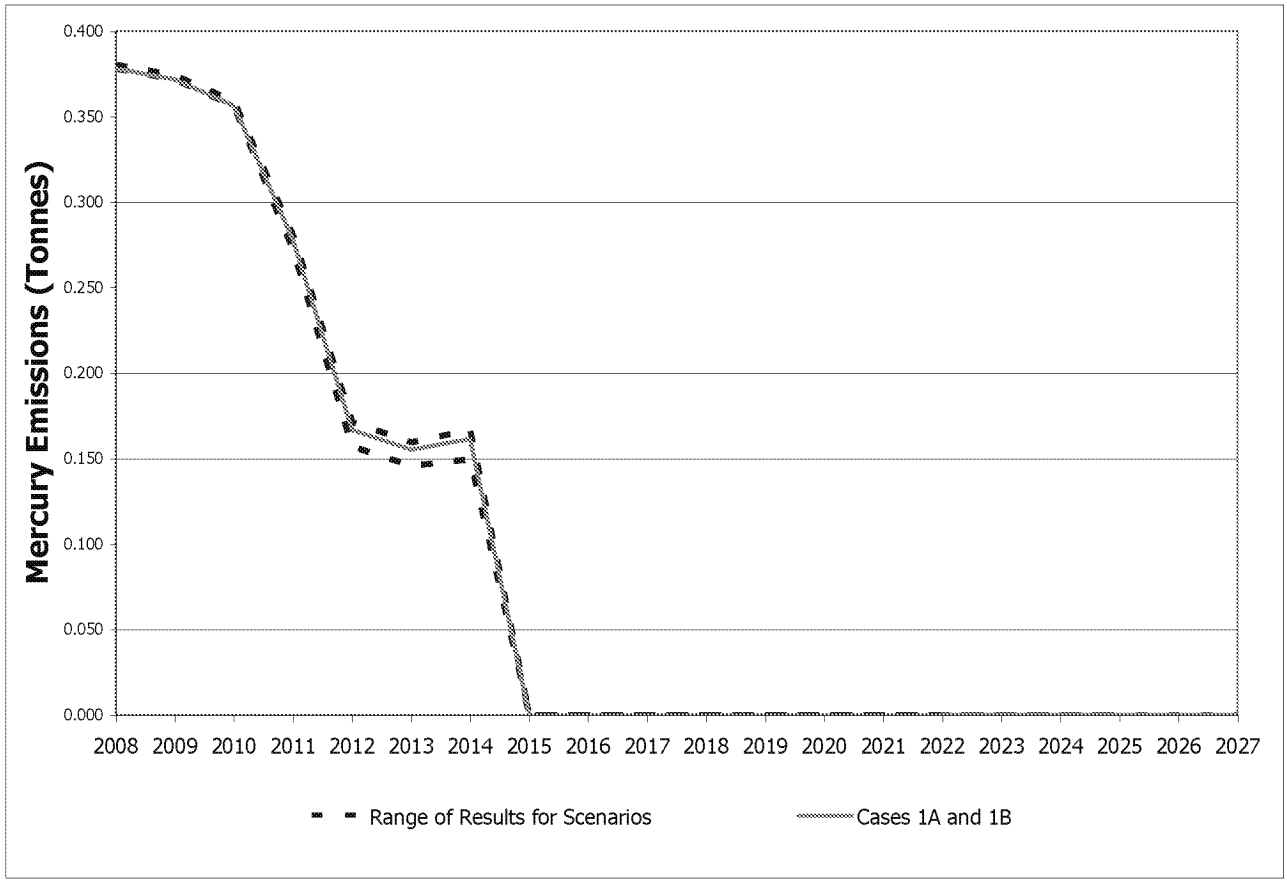
Figure 4: Summary of Sulphur Dioxide Emissions



Source: OPA

Mercury emissions are only associated with coal-fired power and thus they are eliminated with the phase-out of coal. As illustrated in Figure 5, by 2015, there are no mercury emissions associated with electricity generation in Ontario.

Figure 5: Summary of Mercury Emissions to Air



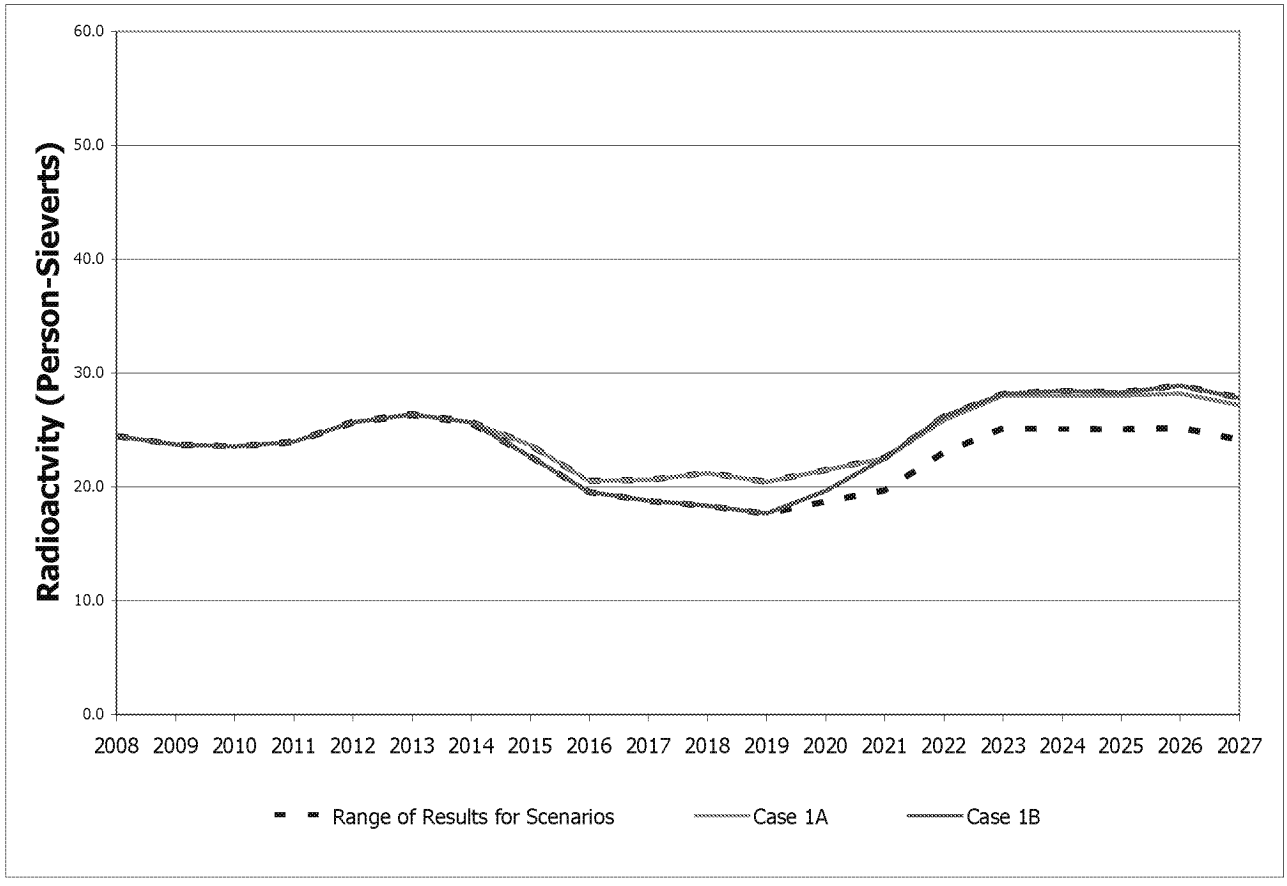
Source: OPA

Radioactivity

Radioactive emissions[11] are primarily associated with the operation of nuclear power plants. In the Plan, the minor additional contributions to radioactive emissions arising from the combustion of fossil fuels (coal and natural gas) are also included. Exposure to radioactive emissions at the end of the Plan period are at similar levels to 2008, with the small increase primarily related to the increase in nuclear energy output in the later years of the Plan. Exposures to radioactivity decline from 2014 to 2019, as shown in Figure 6, and rise moderately to plateau in 2023 consistent with nuclear output in the Plan. The reduction in radioactive emissions in the interim period (2014 to 2020) results from nuclear

refurbishment activities. If the Pickering B plant is refurbished (Case 1A), the radioactive emissions decline in the interim period. If the Pickering B plant is not refurbished, they decline even further.

Figure 6: Summary of Radioactive Emissions in Collective Effective Dose



Source: OPA, SENES, 2007 (Attachment 1 to this exhibit at p. 3-15)

Radioactive emissions from normal operations at existing nuclear sites in Ontario have typically been at or less than 1% of the derived emission limits prescribed by the CNSC. Additional detailed information on the releases of radioactivity and compliance of nuclear facilities is available through the CNSC.

[11] The radioactivity emission rates and collective effective dose are obtained from the United Nations Scientific Committee of the Effects of Atomic Radiation (UNSCEAR, 2000).

Water Use

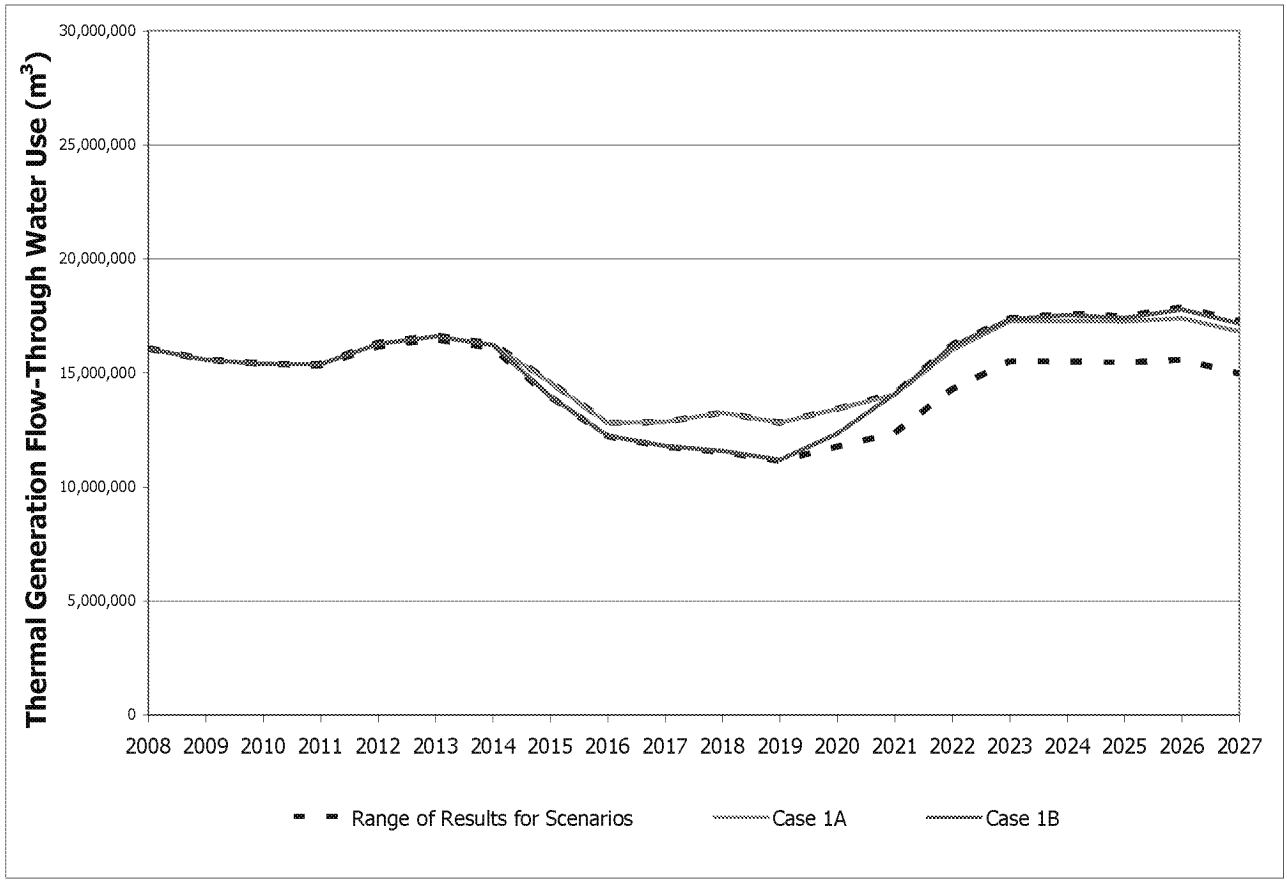
The results for non-consumptive and consumptive water use are described below as flow-through water use and water consumption.

Flow-through water use represents water that is withdrawn and returned to the system from which it came. Thermal generation stations that are situated on bodies of water withdraw water for cooling purposes and return that water to the system, along with some heat ejected from the power plant. The flow-through water use for thermal generation facilities is shown in Figure 7. The analysis shows that flow-through water use in 2027 is slightly higher than current levels, with decreased flow-through water use during the 2014 to 2022 period.

The decrease in water use during the medium-term is largely due to nuclear plant refurbishments, as nuclear plants typically require large volumes of water for cooling. The slight increase near the end of the planning period indicates that attention will have to be paid to the effects of thermal discharge from power plants situated on bodies of water.

The flow-through water used by hydroelectric facilities is not included in Figure 7. The volume of water passed through hydroelectric turbines in Ontario is much larger than the amount of flow-through water required by thermal generation plants. For example, in 2006, Ontario Power Generation reports that about 450 billion m^3 of water passed through the turbines at its hydroelectric stations.

Figure 7: Summary of Thermal Generation Flow-through Water Use

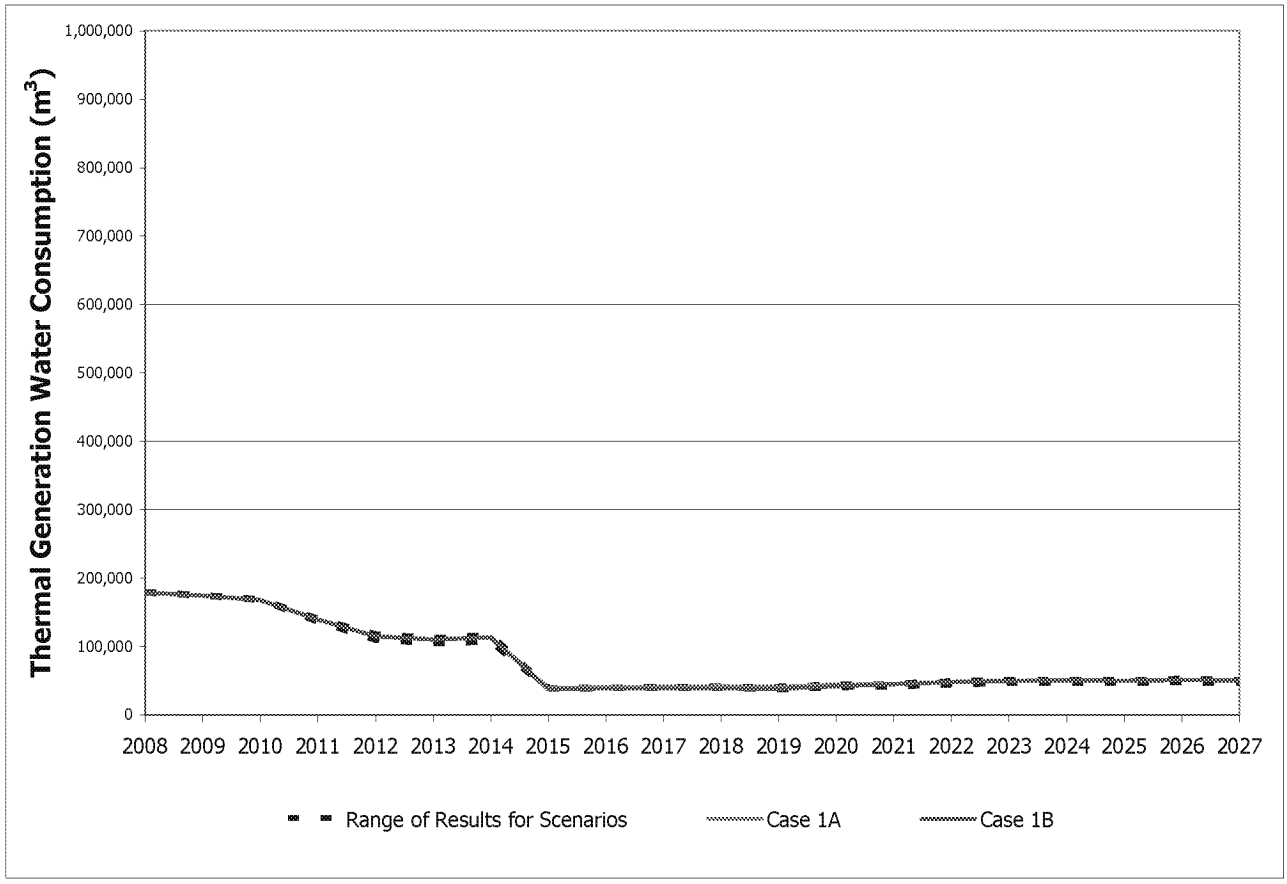


Source: OPA

Water consumption is shown in Figure 8. A substantial decrease in water consumption results from the phase-out of coal-fired power. Much of the water used in coal-fired facilities is from the operation of pollution control equipment, such as flue gas desulphurization equipment.

Water consumption at the end of the Plan period in 2027 is significantly lower than at the beginning of the Plan period (approximately one-third the level of water use compared to 2008).

Figure 8: Summary of Thermal Generation Water Consumption



Source: OPA

Determining site-specific or local and regional impacts on water quality, such as thermal discharges or releases of effluents from electricity generation facilities, would require additional assessments. Such information is typically provided in supporting EA analyses and managed through regulatory licensing and EA approvals.

Solid Wastes

Solid wastes are only produced by coal and nuclear technologies, with negligible amounts produced by biomass and other generation technologies. Natural gas may produce solid wastes only when flue gas scrubbing equipment is cleaned, which occurs infrequently (i.e., once every few years).

Figure 9 illustrates the production of solid wastes during the course of the IPSP. In the near-term, the existing coal plants produce the majority of solid wastes. These solid wastes include ash and pollution control equipment residues (e.g., gypsum) that are not recycled, reused or diverted from landfills.

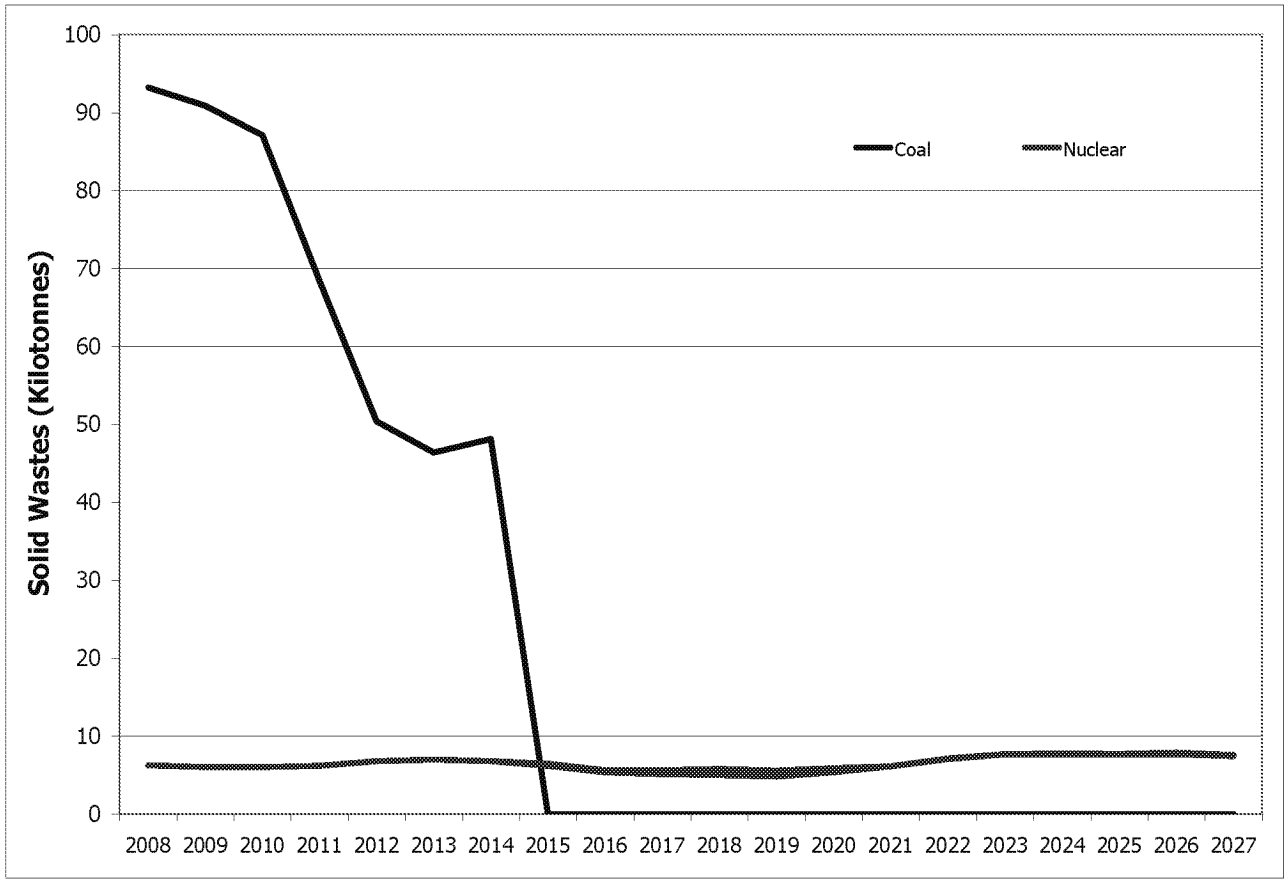
According to SENES (2007), the estimated amount of solid waste produced by electricity sector operations in the year 2008 is 99 kilotonnes ("kT"), of which about 6.2 kT is produced by nuclear facilities. In the year 2027, the total amount of solid wastes is 92% less than at the start of the Plan period. This decrease is a result of the elimination of coal-fired power.

The solid waste produced by nuclear facilities includes used fuel and low and intermediate radioactive materials. In 2027, the amount of solid waste from nuclear facilities is estimated to be about 7.5 kT, representing an increase of 20% over the annual production in 2008 (6.2 kT). According to SENES[12], the amount of used fuel produced in the year 2008 is 2.4 kT. Based on the amount of nuclear energy produced in 2027, the annual used fuel production at the end of the Plan period is estimated to be approximately 2.9 kT and the amount of low and intermediate radioactive wastes would be approximately 4.6 kT. This indicates a 20% increase in the production of used fuel at the end of the Plan period.

The estimate of used fuel in the wastes generated is intended to indicate a trend that reflects the role of nuclear generation output in the Plan.

[12] See SENES, 2007, page A-14, Table A.11 (Attachment 1 to this exhibit).

Figure 9: Summary of Generation of Solid Wastes



Source: OPA

Land Use

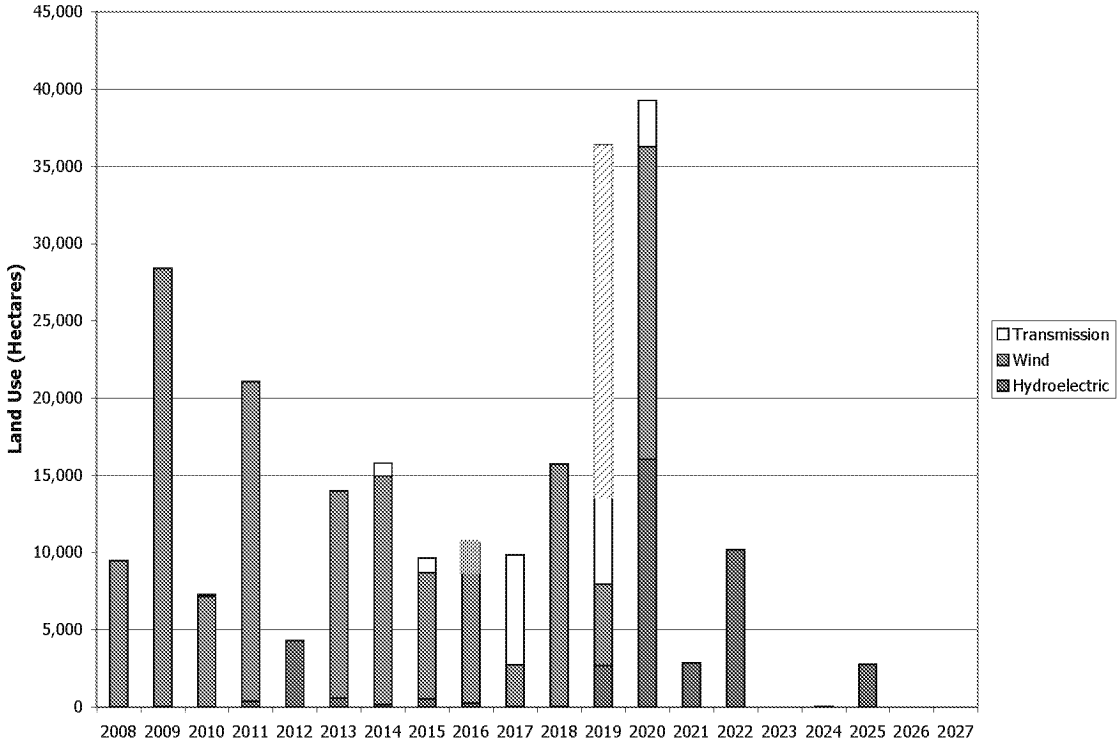
Land use requirements in the IPSP vary according to the types of projects that are expected to be built over the course of the Plan. The supply resources with the most land use requirements are new wind and new hydroelectric resources with reservoirs. Because land use is highly dependent on the nature and quantity of either wind or water resources at a specific site, the information on land use should be considered as being indicative only.

Figure 10 shows the year by year estimate of land use requirements over the course of the Plan. Most of the land requirements are for new wind resources. Wind turbines and associated access roads and ancillary equipment occupy generally less than 5% of the total land use requirements of a wind farm. For example, wind farms require large land

areas but a significant proportion of this land remains ecologically productive and available for other uses for the duration of operation of the wind farm. The land use requirements for hydroelectric projects are indicative of flooding that may be associated with reservoirs, but that would depend on the quality of the water resource and topography at a specific site. Therefore, the total land use requirement represented by the projects in the IPSP would be significantly less than those shown in Figure 10.

The cumulative additional land use requirement for new electricity supply and transmission resources over the twenty year Plan is approximately 2,100 km^2. Roughly 1,500 km^2 of this area is represented by wind farms, 400 km^2 by hydroelectric flood areas and 200 km^2 for transmission corridors. The land occupied by Ontario's current electricity supply resources is about 1,200 km^2 using the same land use factors, as provided in SENES (2007). Compared to the total area of Ontario (917,741 km^2), the total land use requirement of the new supply resources in the IPSP is less than 0.3 % of the provincial land base. The land use requirements of transmission lines, versus generating plants, involve linear corridors. In the Plan, new transmission projects are intended to facilitate the development of new renewable resources (see Exhibits E-3-1, E-3-3, to E-3-7, and E-3-9 and E-3-10 for assessments of the environmental considerations related to land use associated with major transmission corridors.

Figure 10: Summary of Land Use Requirements



Source: OPA
Note: This chart shows the total land occupied by new wind farms, where over 95% of these lands remain available for other uses and ecologically productive during operation of the wind farm. The orange shaded area represents the potential land use associated with the option to purchase electricity from Quebec/Labrador and the grey shaded area represents the potential land use associated with the option to purchase electricity from Manitoba.

3.4 Summary of Results

The IPSP analysis has quantified and considered key environmental indicators. These are:

- Greenhouse gas emissions;
- Air contaminant emissions;
- Radioactivity;
- Water use (consumptive and non-consumptive);
- Solid wastes; and
- Land use.

A consideration of the likely environmental effects associated with the Plan are shown as trends for each indicator. The results show:

- substantial reductions in SO_2, NO_x, fine particulate and GHG emissions, plus the elimination of mercury emissions arising directly from the phasing out of coal;
- exposure to radioactive emissions at the end of the Plan period are at similar levels to 2008, with the small increase primarily related to the increase in nuclear energy output in the later years of the Plan;
- land use increases due to a larger role for new renewable resources and the requirements for transmission to support renewable generation, but much of this land will remain ecologically productive and available for other uses;
- water consumption decreases drastically, primarily because of coal replacement, while flow-through water use remains steady over the course of the Plan; and
- solid wastes production decreases substantially over the course of the Plan while the production of radioactive wastes increases slightly coincident with nuclear output.

4.0 APPENDIX A: AGENCIES WITH MANDATES TO ENSURE ENVIRONMENTAL PROTECTION, PUBLIC AND WORKER SAFETY

A partial list of agencies and organizations that work to ensure safety with respect to electricity sector development and operations is as follows:

4.1 Federal Government

4.1.1 Canadian Nuclear Safety Commission ("CNSC")

The CNSC regulates the use of nuclear energy and material to protect health, safety, security and the environment and to respect Canada's international commitments on the peaceful use of nuclear energy.

Nuclear Safety and Control Act, 1997, c. 9, N-28.3. [Assented to March 20th, 1997]

- provides the CNSC with its regulatory authority;
- limits, to a reasonable level and in a manner that is consistent with Canada's international obligations, the risks to national security, the health and safety of persons and the environment that are associated with the development, production and use of nuclear energy and the production, possession and use of nuclear substances, prescribed equipment and prescribed information; and
- implements measures to which Canada has agreed respecting international control of the development, production and use of nuclear energy, including the non-proliferation of nuclear weapons and nuclear explosive devices.

4.1.2 Nuclear Waste Management Organization ("NWMO")

The NWMO is established under the *Nuclear Fuel Waste Act* to investigate approaches for managing Canada's used nuclear fuel.

Nuclear Fuel Waste Act

- provides a framework to enable the Governor-in-Council to make, from the proposals of the NWMO, a decision on the management of nuclear fuel waste that is based on a comprehensive, integrated and economically sound approach; and

- requires companies producing nuclear fuel waste to establish a waste management organization to provide recommendations to the Government of Canada on the long-term management of used nuclear fuel and establish segregated trust funds to finance the long term management of the used fuel.

4.1.3 Canadian Environmental Assessment Agency

Canadian Environmental Assessment Act, 1992, c. 37C-15.2. [Assented to June 23rd, 1992]

- provides for projects to be considered in a careful and precautionary manner before federal authorities take action in connection with them in order to ensure that such projects do not cause significant adverse environmental effects;
- ensures that there is an opportunity for public participation in the environmental assessment process;
- promotes communication and cooperation between federal authorities and Aboriginal peoples;
- encourages responsible authorities to take actions that promote sustainable development and thereby achieve or maintain a healthy environment and a healthy economy;
- encourages federal authorities to take actions that promote sustainable development;
- promotes cooperation and coordinated action between federal and provincial governments on environmental assessments; and
- ensures that development in Canada or on federal lands does not cause significant adverse environmental effects in areas surrounding the project.

4.1.4 Environment Canada

Environment Canada coordinates environmental policies and administers acts either in whole or in part or assists with the administration of other legislation that has a role in environmental protection. Environment Canada administers the *Canadian Environmental Protection Act (1999).*

4.1.5 Health Canada

Health Canada and the Public Health Agency of Canada develop and enforce regulations under Government of Canada legislation. The Departments consult with the public, industry and other interested parties in the development of laws that protect health and safety.

Health Canada's roles and responsibilities are defined in the *Department of Health Act.*

Department of Health Act 1996, c. 8H-3.2 [Assented to May 29th, 1996]

- Deals with federal legislation related to radiological and nuclear emergencies

Emergencies Act, 1985, c. 22 (4th Supp.) E-4.5

- An Act to authorize the taking of special temporary measures to ensure safety and security during national emergencies and to amend other Acts in consequence thereof

Emergency Preparedness Act, 1985, c. 6 (4th Supp.) -4.6

- An Act to provide for emergency preparedness and to make a related amendment to the National Defence Act

Health Canada deals with federal legislation related to environmental and workplace health, and aims to reduce the health and safety risks associated with different types of radiation:

- conducts research into the biological effects of environmental and occupational radiation;
- develops methods for internal radiation dosimetry and its measurement;
- provides radiation safety inspections of federally regulated facilities containing radiation-emitting devices, the devices themselves, as well as training on the proper operation of the devices;

- develops regulations, guidelines, standards and safety codes pertaining to radiation-emitting devices;
- provides radiation advice and collaborates with government departments and agencies, industry, and the general public; and
- takes part in the International EMF Project, coordinated by the World Health Organization to verify reported biological effects from exposure to electromagnetic fields and to characterize any associated health risks to humans.

4.1.6 Natural Resources Canada – Electricity Resources Division

The Nuclear Energy Division and the Uranium and Radioactive Waste Division are part of the Energy Sector of Natural Resources Canada. Together these two Divisions provide leadership in the development and implementation of Canadian government policy on uranium, nuclear energy and radioactive waste management.

4.1.7 National Energy Board

Safety is a matter of primary public interest and has been included in the National Energy Board's mandate since 1959. The Board is responsible for ensuring companies comply with regulations concerning the safety of employees, the public, and the environment, as they may be affected by the design, construction, operation, maintenance and abandonment of a pipeline.

- *National Energy Board Act*. R.S., c. N-6, s. 1.

4.2 Provincial Government

4.2.1 Ministry of Labour

Occupational Health and Safety Act. R.S.O. 1990, CHAPTER O.1 Last amendment: 2007, c. 8, s. 221.

- sets out the rights and duties of all parties in the workplace. Its main purpose is to protect workers against health and safety hazards on the job. The Act establishes

procedures for dealing with workplace hazards, and it provides for enforcement of the law where compliance has not been achieved voluntarily.

Workplace Safety and Insurance Act, 1997 S.O. 1997, CHAPTER 16, Schedule A

- promotes health and safety in workplaces to prevent and reduce the occurrence of workplace injuries and occupational diseases;
- facilitates the return to work and recovery of workers who sustain personal injury arising out of and in the course of employment or who suffer from an occupational disease;
- facilitates the re-entry into the labour market of workers and spouses of deceased workers; and
- provides for compensation and other benefits to workers and to the survivors of deceased workers.

4.2.2 Workplace Safety and Insurance Board

The Workplace Safety and Insurance Board's purpose is to eliminate workplace injuries and illnesses. This is done by promoting and sharing information and resources that help workplaces make their work safe.

- Works with the Ontario Ministry of Labour

4.2.3 Ministry of the Environment

MOE is responsible for protecting clean and safe air, land and water to ensure healthy communities, ecological protection and sustainable development for present and future generations of Ontarians. It administers the *Environmental Assessment Act* and conducts air quality monitoring and reporting.

4.3 Electricity Sector Agencies

4.3.1 Electrical Safety Authority

The Electrical Safety Authority ("ESA") is a stand-alone, not-for-profit corporation that operates as an administrative authority under the *Electricity Act, 1998* and through an agreement with the Ministry of Government Services. ESA is responsible for public electrical safety in Ontario as designated by Ontario Regulation 89/99.

- ESA is accountable to the public through the Ministry of Government Services for meeting its legislative and contractual obligations in the delivery of its delegated regulatory mandate.

Ontario Electrical Safety Code ("OESC")

- The OESC describes the standards for electrical installations. It is primarily a technical document and it is prescriptive in approach.

4.3.2 Canadian Standards Association

The Canadian Standards Association develops standards that are intended to enhance public safety and health.

4.3.3 North American Electric Reliability Corporation ("NERC")

NERC's mission is to improve the reliability and security of the bulk power system in North America. To achieve that, NERC develops and enforces reliability standards; monitors the bulk power system; assesses future adequacy; audits owners, operators, and users for preparedness; and educates and trains industry personnel. NERC is a self-regulatory organization that relies on the diverse and collective expertise of industry participants. NERC is subject to audit by the U.S. Federal Energy Regulatory Commission and governmental authorities in Canada

4.3.4 Northeast Power Coordinating Council

Northeast Power Coordinating Council, Inc.'s ("NPCC") mission is to promote the reliable and efficient operation of the interconnected bulk power systems in northeastern North America through the establishment of criteria, coordination of system planning, design and operations, and assessment of compliance with such criteria. In the development of reliability criteria, NPCC, to the extent possible, facilitates attainment of fair, effective, and efficient competitive electric markets.

NPCC's Compliance Program is designed to monitor, assess and enforce compliance in accordance with NPCC Criteria and NERC Reliability Standards

Federal Legislation

- *Nuclear Energy Act (R.S., 1985, c. A-16)*
- *Comprehensive Nuclear Test-Ban Treaty Implementation Act (1998, c. 32)*
- *Hazardous Products Act (R.S., 1985, c. H-3)*
- *Nuclear Safety and Control Act (1997, c. 9)*
- *Radiation Emitting Devices Act (R.S., 1985, c. R-1)*
- *Transportation of Dangerous Goods Act, 1992 (1992, c. 34)*
- *Nuclear Fuel Waste Act. Canada Gazette, Part III, Volume 25, No.2, Chapter 23. Ottawa, Friday, August 2, 2002, Statutes of Canada 2002.*
- *Emergencies Act 1985, c. 22 (4th Supp.) E-4.5*
- *Emergency Preparedness Act 1985, c. 6 (4th Supp.) -4.6*

Provincial Legislation

- *Electricity Act, 1998*
- *Public Health Act of 1882*
- Ontario Electrical Safety Code

5.0 APPENDIX B: DESCRIPTION OF ENVIRONMENTAL INDICATORS

This appendix presents a more detailed description of the environmental indicators used in this analysis. Additional information regarding these indicators is included in SENES (2007).

Greenhouse Gas Emissions

Gases in the atmosphere that are responsible for absorbing outgoing heat radiated by the earth are called "greenhouse gases" ("GHGs"). These gases are naturally present in the atmosphere and, in fact, they keep Earth warm enough to support life. Ongoing increases in the atmospheric concentration of these gases, both natural and more recently, man-made, have led to increased concern about increasing mean global temperatures and more frequent droughts and extreme weather events. The Intergovernmental Panel on Climate Change ("IPCC") has reported that human contributions are likely contributing to observed climate trends such as warmer and more frequent hot days and warmer and fewer cold days over most land areas, which have direct implications for Ontario's electric system, both in terms of summer air conditioning loads and the availability of hydroelectric power.

Three GHGs, carbon dioxide (CO_2), methane (CH_4) and nitrous oxide "N_2O) are included in the environmental analysis. Carbon dioxide has received most of the climate change attention because its atmospheric concentration has risen steadily due the combustion of fossil fuels. Methane and nitrous oxide are present in the atmosphere at concentrations much lower than that of CO_2, but together, these three gases are the primary GHGs emitted by the electricity sector. In Canada, these GHG emissions are reported by electricity sector participants to the national GHG inventory.

Global warming potential ("GWP") is used to express the ability of particular gases to contribute to the greenhouse effect. The GWP of CH_4 and N_2O are 21 and 310 times the GWP of CO_2, respectively. In addition to their being more effective absorbers of long wave radiation than CO_2, these gases also absorb wavelengths in regions where CO_2 is

transparent. For reporting, these gases are "normalized" according to their respective GWP. These gases have long residence times in the atmosphere and thus, they contribute to the greenhouse effect long after they are emitted. In addition, these long residence times allow GHGs to become thoroughly mixed in the atmosphere, reducing the relevance of the location at which they are released.

An additional important GHG used in specialized electricity applications is sulphur hexafluoride (SF_6). Sulphur hexafluoride is used as an insulating gas in electrical equipment. Some SF_6 is emitted during installation, service and disposal of equipment such as circuit breakers, gas-insulated substations and switchgears. The global warming potential of SF_6 is 23,900 times that of CO_2 over a 100 year period. Because its mixing ratio in the atmosphere is lower than that of CO_2 (about 0.005 ppm versus 365 ppm), its overall contribution to global warming is low. Industry best practice involves recapture of SF_6 gas during maintenance activities to reduce emissions to a very low level, but small amounts of SF_6 gas are released to the atmosphere through leaking seals and electrical equipment.

For the analysis, GHG emissions have been derived from Environment Canada's national inventory and GHG Emissions Reporting program. Emission rates are expressed as a mass of gas (e.g., tonnes of CO_2 equivalents) per unit of net electricity produced (e.g., per megawatt-hour delivered to the grid). The emission rates for the class of facility (e.g., combined cycle gas turbines) represent the average in cases where there is information for more than a single facility. For facilities that are not represented in the national inventory (e.g., single cycle gas turbines), emission factors were derived from facilities reporting to the US Environmental Protection Agency. [13,14]

[13] In some cases, such as for Ontario Power Generation's (OPG) existing coal fleet, emission rates for specific units have been provided by OPG.
[14] Refer to SENES, 2007 for details (Attachment 1 of this exhibit).

Air Contaminant Emissions

Four contaminant air emissions included in the analysis are oxides of nitrogen (NO_x), sulphur dioxide (SO_2), fine particulate matter ($PM_{2.5}$) and mercury. These emissions have been selected because they are important contributors to potential adverse effects on human health, ecosystems or the built environment. They are routinely associated with the operation of power generation facilities.

Each of the four contaminant air emissions is described in further detail in the following subsections. For emissions of contaminants to the air, actual emissions as reported to the National Pollutant Release Inventory ("NPRI") are used where possible. The emissions considered in the analysis are prorated to the amount of electricity delivered to the Ontario grid for each facility type, over the same time period to derive an emission rate. Emissions rates are expressed as a mass of pollutant emitted per megawatt hour of energy produced (e.g., kg/MWh). The emission rate for a class of facility (e.g., combined cycle gas turbines) represent the average in cases where there is information for more than a single facility.[15] For facilities that are not represented in the NPRI database (e.g., single cycle gas turbines), emission factors were derived from facilities reporting to the US Environmental Protection Agency.[16]

Oxides of Nitrogen (NO_x)

These compounds include nitrogen dioxide (NO_2) and the more reactive nitric oxide (NO) ion. During fossil fuel and biomass combustion, the majority of the NO_x is formed as NO, but this reactive compound is quickly oxidized to NO_2 in the ambient air upon release in stack gases. Coal, natural gas and biomass fuels (including biogas) naturally contain varying degrees of fuel-borne nitrogen compounds, but the more prominent source of NO_x emissions results when naturally occurring atmospheric nitrogen combines with oxygen in the high temperature zone of combustion processes.

[15] In some cases, such as for Ontario Power Generation's (OPG) existing coal fleet, emission rates for specific units have been provided by OPG.
[16] Refer to SENES, 2007 for details (Attachment 1 of this exhibit).

NO_x compounds have local and regional effects. NO_2 can cause direct health effects and reduce visibility due to its light scattering reddish-brown colour, but the formation of secondary pollutants via a complex array of chemical reactions in the atmosphere is also a concern. Acid rain is formed when NO_x combines with water. Ground level ozone is formed when NO_x reacts with naturally occurring hydroxyl radicals and other volatile hydrocarbons emitted by automobiles and industrial processes.

Sulphur Dioxide (SO_2)

Sulphur dioxide (SO_2) is the most prominent oxide of sulphur associated with fossil fuel combustion. Emissions of sulphur compounds are directly related to the sulphur content of the fuel. Coal combustion is the primary source of sulphur emissions. When coal is burned, the sulphur in coal is oxidized to form sulphur dioxide (SO_2). Sulphur dioxide gas is strongly adsorbed onto the surface of particulate matter, and the particulates catalyze the oxidation of SO_2 to sulphur trioxide (SO_3) in moist conditions. Sulphur trioxide immediately combines with water to form sulphuric acid (H_2SO_4). These particles are removed from the atmosphere through wet deposition processes such as acid rain, and inhalation of these tiny particles can damage the respiratory system. Their high solubility in water causes sulphur oxides to act as strong corrosives to building materials.

Hydrogen sulphide (H_2S) gas is also produced when sulphur compounds are heated. H_2S is toxic, but is readily oxidized to SO_2 in the atmosphere.

Fine Particulate Matter

Particulate matter is generally used to describe particles that are suspended in the atmosphere. The class of particulate matter with diameters less than 2.5 μm (fine particulates or $PM_{2.5}$) are of greatest concern to human health because they are respirable. These particles can be organic, inorganic, solids or aerosols. Some previously described pollutants, such as NO_2, also exhibit the properties of particulate

matter. These particles can also act as catalysts for the oxidation of sulphur dioxide, which causes acid precipitation and reduction of visibility.

A complete data set for $PM_{2.5}$ is not available for all electricity resource options and therefore, in some cases, PM_{10} (diameters less than 10 μm) have been used in the analysis. This results in quantifications of PM that provide a conservative upper bound on the likely impacts.

Mercury

Mercury is emitted from coal combustion. In most cases, organic mercury compounds are more toxic than inorganic forms. In the environment, inorganic mercury is transformed to the organic form, methyl mercury, which then bioaccumulates in the tissues of animal species and fish. Methyl mercury easily enters the body through inhalation or ingestion of contaminated tissues. Long-term exposure to either the organic or inorganic forms of mercury can cause permanent brain and kidney damage, as well as damage developing fetuses.

Mercury emissions to air are considered in the environmental analysis of the Plan.

Radioactivity

This measure considers releases of radioactivity to the environment from nuclear generation resources. Various radionuclides are released from the operation of nuclear plants. The radionuclides released vary by type of reactor and from reactor to reactor, but include such species as noble gases, radioactive particulate matter and tritium. Methods for converting exposure to any radionuclide to a common unit, namely "collective effective dose" are well established and used by the Canadian Nuclear Safety Commission for license compliance and reporting. Radioactive emissions and collective effective dose information from nuclear and fossil fuel cycles are reported by the United Nations Scientific Committee of the Effects of Atomic Radiation (UNSCEAR, 1993; 2000). Radiological emissions for all other generation resources (e.g., wind, solar, bioenergy) are negligible.

UNSCEAR's mandate is to assess and report levels and effects of ionizing radiation, and organizations worldwide rely on the Committee's estimates as the scientific basis for evaluating radiation risk. Emissions to air, water and land from operating nuclear facilities in Ontario and Canada are reported by the CNSC.

Water use

The water use category is intended to capture the use of water, both consumptive and non consumptive ("flow-thorough" water), by generation options. Since water use is a direct result of facility operations, cubic metres per megawatt hour is an appropriate metric.

It is important to distinguish between the amount of water that is withdrawn and the amount that is not returned (consumed). Both numbers are presented in terms of cubic metres per megawatt hour of power generated. This is intended to reflect water use, but this measure is also useful for identifying situations where there is potential for effects on aquatic biology and physical characteristics of water, such as temperature and dissolved oxygen.

The amount of water consumed or flowing through and subsequently returned to a water body has been derived by reviewing environmental assessment reports, estimates of water use at existing facilities, or in published reports.

Land use

This measure is intended to provide an indication of the amount of physical land area occupied by particular generation or transmission options. Land use is important for all generation options with the exception of solar PV and fuel cells which in the IPSP are assumed to be located on or in existing buildings and infrastructure. The land use calculation reflects the facility footprint or the area required for the facility and associated components (i.e., inside the fence).

Land use is a function of the construction and ongoing presence of the facility and therefore area per megawatt, not per megawatt hour, is the appropriate metric. The land use of power generation and transmission facilities has been estimated using actual facilities,

either as stated in environmental assessment reports or as estimated from the actual facility footprint using satellite imagery. In several cases, multiple facilities of a similar class and time period have been used to derive an average value for land use. For transmission lines, a land use metric is determined based on an assumed right-of-way width of 45 m for 230 kV lines and 120 m for 500 kV lines.

Wastes

This measure is intended to include wastes generated during the operation phase of power plants, but excludes decommissioning wastes generated at the end of the facility's life cycle. Wastes generated by activities related to the production of electricity are reported in terms of mass (e.g., kilograms) produced per megawatt hour per year. Conventional solid or chemical wastes such as cans, cardboard, paper, newspaper, plastic, metals and glass, office or cleaning products are not included in this analysis as they are common to all generation stations.

Wastes generated by power plants is estimated from published reports and conversations with plant operators. Total wastes generated have been divided by the amount of electricity produced by the facility to derive an estimated emission rate. Effects related to specific toxicity of waste streams are managed through regulatory compliance, however, the OPA has made some observations of toxicity if a particular energy option is the source of such wastes that require special attention.

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21 June 2007

Ontario Power Authority
120 Adelaide Street West, Ste. 1600
Toronto, ON
M5H 1T1

Attention: **Amir Shalaby**

RE: **Supplementary Environmental Impacts Report for the Integrated Power System Plan – Final Report**

Dear Amir Shalaby,

Enclosed please find five (5) copies and an electronic version (pdf) on a CD of the final report entitled *Supplementary Environmental Impacts Report for the Integrated Power System Plan*. We were pleased to work on such a challenging and rewarding project.

Yours very truly,

SENES Consultants Limited



Donald M. Gorber, Ph.D., P.Eng.
President

Att.

Ontario Power Authority

Final Report:

SUPPLEMENTARY ENVIRONMENTAL IMPACTS REPORT FOR THE INTEGRATED POWER SYSTEM PLAN



Prepared For:

The Ontario Power Authority

Prepared By:

SENES Consultants Limited

June 2007

Supplementary Environmental Impacts Report for the Integrated Power System Plan

Prepared for:

The Ontario Power Authority

Prepared by:

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June 2007

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1.0 INTRODUCTION

1.1 TERMS OF REFERENCE

In November 2005, SENES Consultants Limited prepared ***"Methods to Assess the Impacts on the Natural Environment of Generation Options"*** for the Ontario Power Authority (OPA). The 2005 SENES report provided a method for evaluating the natural resource impacts and sustainability of electricity generation options for the province of Ontario. SENES employed a life cycle approach to broadly review environmental impacts. The environmental impacts were not site specific, but were generalized and assessed across the range of generation options in order to allow for comparison between different types of generation. In the 2005 report, electrical generation options that were evaluated included thermal, nuclear, hydroelectric and renewables. In addition, consideration was made for the Ontario-Manitoba Interconnection project which would see transmission of power generated in Manitoba to southern Ontario.

In order to evaluate the potential environmental impacts for different generation options, environmental criteria were developed that could assess a range of potential impacts, including emissions to air, the generation of solid wastes and the use of water and land on a per megawatt (MW) or per megawatt-hour (MWh) basis. Evaluating generation options according to power production enabled comparisons to be made between generation types based on their relative potential environmental effects. Complementary to these criteria, a fifth criterion was developed to assess the sustainability of different generation options according to the estimated longevity of the fuel resource. The final component of the method developed in 2005 was to rank each generation option according to these criteria. This allowed for a final score to be awarded to generation options based on their environmental performance.

Over the past year, a more refined list of generation options as well as transmission options have been developed by the OPA in response to the Ontario government's directives with respect to the Ontario electrical supply mix. This work is leading to the development of the Integrated Power System Plan (IPSP) for Ontario's electricity system (OPA 2007b). The OPA is now seeking a better understanding of the potential for environmental effects of the generation and transmission facilities in the IPSP and SENES has been engaged to provide a method for such analyses by supplementing the 2005 work. This report updates the earlier report according to the supply mix provided by the OPA in its Preliminary Plan and by furthering the methodology created by SENES. The objective of this methodology is to provide the OPA with tools necessary to compare the environmental performance of Ontario's power system both before and after implementation of the IPSP. The time frame for this analysis is 2007 to 2027 for full implementation of the IPSP.

1.2 REPORT OVERVIEW

This report provides a high level view of the environmental impacts of the OPA's revised resource assumptions in the IPSP and is based on the following principles:

- The resource assumptions regarding electrical generation and transmission options are as specific as possible given the current information and the developing state of the IPSP.
- Environmental performance criteria are based on those described in the 2005 SENES report with updated data based on Ontario specific information where available.
- Modifiers are comparable to those in the 2005 SENES report, but have been refined to account for specific sites or regional characteristics, where possible.

This report describes the assumed electrical resource options in Chapter 2. Chapter 3 provides a description of the environmental performance criteria as well as criteria factor values. Chapter 4 provides an overview of how the data in Chapter 3 may be used to provide an indication of the environmental performance of the IPSP supply mix as well as methodological recommendations for the use of weighting of criteria. Appendix A provides the raw data used to calculate the criteria factor values while Appendix B provides revised modifiers that can be applied to the criteria factor values when detailed comparisons of options is required.

2.0 DESCRIPTION OF ELECTRICITY RESOURCE OPTIONS EVALUATED

This chapter contains the basic assumptions for the electricity resource options, including conservation and demand management, generation and transmission, which were used in this evaluation. These resource assumptions were provided by OPA only as potential electrical resources that are being considered in the IPSP and it has been SENES' understanding that these resource assumptions continue to evolve in the development of the IPSP.

2.1 CONSERVATION AND DEMAND MANAGEMENT

While conservation and demand management (CDM) will form a large part of the IPSP, the environmental performance of individual CDM programs and resources has not been included in the current analysis. The nature of CDM initiatives is highly diverse, and many programs, such as conservation and time-of-use pricing, will likely have a net positive environmental benefit because they displace the requirement to generate electricity. Some CDM resources, such as fuel switching and small-scale generation, may have effects due to emissions, but the environmental performance of some of these technologies is difficult to estimate at present.

The methodology provided in this report is capable of incorporating the environmental performance of CDM resources as more information becomes known about these attributes.

2.2 NATURAL GAS

The resource assumptions in the IPSP include generation from natural gas from the following:

Lennox Generating Station

Operated as both an oil and natural gas fired station, Ontario Power Generation's (OPG) Lennox Generating Station is a special case with respect to current power production in Ontario. During the summer, the plant utilizes natural gas to fire its four units while both oil and gas are used in the winter due to increased cost and demand for natural gas for heating (OPG, 2007f).

Combined Heat and Power

Combined heat and power (CHP), also known as cogeneration, is the production of electricity and thermal energy from a common fuel source; in this case it is assumed to be natural gas.

Combined Cycle Gas Turbines

A combined cycle gas turbine (CCGT) is a combination of combustion and steam turbines to generate electricity from two thermodynamic cycles. Although most of the electricity comes from the gas turbine (typically 60-70% of the power), the combined power of the combustion and steam cycles substantially improves the thermal efficiency of combined cycle over a single cycle gas turbine (SCGT).

Single Cycle Gas Turbines

SCGTs use combustion gases to drive a turbine connected to an electrical generator.

2.3 COAL

Conventional Coal

The IPSP resource assumptions indicate that Ontario's existing coal-fired power plants will be replaced by other resources during the 2007-2027 period.

Coal has been an important part of Ontario's electricity supply mix since the early 1950s. This analysis includes Ontario's four existing coal stations as the basis for conventional coal's environmental performance: Atikokan, Lambton, Nanticoke and Thunder Bay.

Integrated Gasification Combined Cycle

Producing electricity in an integrated gasification combined cycle (IGCC) plant is similar in principle to a combined cycle station in that a gas turbine generates electricity and surplus heat raises steam to generate additional electricity via a steam turbine. The IGCC plant fuels the turbine with synthetic gas derived from the gasification of liquid or solid carbonaceous materials. The OPA's resource assumptions consider coal as the fuel input to the gasification process, but biomass could also be a conceivable fuel resource for IGCC in Ontario.

There are currently no representative IGCC stations in operation in Ontario and therefore data from other sources, such as the proposed Mesaba IGCC plant in Minnesota, were used to derive estimates of the emissions and potential environmental effects from IGCC plants in Ontario.

2.4 BIOMASS

Biomass is available in Ontario in a variety of forms, amounts and locations, including wood or wood residues, agricultural residues, landfill gas and the organic fraction of municipal solid

waste. The OPA's biomass resource assumptions include the possibility for conversion of an existing coal station to biomass fuel, agricultural residues in southern Ontario, wood residues in northern Ontario, and landfill gas and municipal solid waste in southern Ontario.

Based on the available data, a single set of environmental performance data derived using wood waste as the source of fuel is presented in this report. It is recognized that this may not be representative of all biomass electrical generation. Over time, it is expected that environmental emissions, land and water use information will become known as experience with biomass generation facilities in Ontario grows. Most of the OPA's resource assumptions include some small-scale plants, which may or may not have emissions control equipment.

2.5 NUCLEAR

Environmental performance data for nuclear generation in this report were derived from the three nuclear stations in Ontario: Ontario Power Generation's Darlington Nuclear and Pickering Nuclear as well as Bruce Power Limited Partnership's Bruce Power. Note that conventional air emissions from these nuclear stations includes that from auxiliary and backup systems because these emissions are considered part of the contiguous facility for reporting under the National Pollutant Release Inventory.

2.6 HYDROELECTRIC

Hydroelectric facilities generate electricity by spinning turbines as water flows through the turbines of the station. There are three basic types of hydroelectric generating stations considered in this report.

Peaking

Peaking hydroelectric plants typically use dams to impound water in reservoirs. This analysis assumes that peaking hydroelectric stations require the creation of a reservoir and will result in some degree of flooding.

Baseload

Baseload hydroelectric plants are typically run-of-river and include diversion hydroelectric facilities. This analysis assumes that baseload hydroelectric generation does not involve the creation of a reservoir although small dams may or may not be installed. As would be the case for diversion hydroelectric, water may also be diverted from the natural water course and pass through some form of channel before it passes through the turbine.

Pumped storage

Pumped storage generation allows water to flow from an upper to a lower reservoir to generate electricity when demand is high, and pump water from the lower reservoir to the upper reservoir when electricity demand is low. In this report, the Sir Adam Beck I and II stations are used to represent hydroelectric pumped storage generation.

2.7 WINDPOWER

The resource assumptions in the IPSP include new wind power facilities in the following IESO (2006) zones: Northeast, Essa, Southwest, Bruce, Northwest and East.

2.8 PHOTOVOLTAIC

Photovoltaic systems directly convert the energy from the sun into electricity using semiconductor devices such as crystalline silicon wafers and thin films. The application of larger scale photovoltaic systems is emerging in Ontario, but the technology is in commercial use for off-grid and grid-based applications worldwide. This analysis assumes that all photovoltaic technology in the resource assumptions of the IPSP will be located in urban centres (i.e., on building rooftops) and not result in new land use.

2.9 FUEL CELLS

Fuel cells use electrodes in an electrolyte to generate electricity, providing power as long as there is a source of fuel to generate hydrogen. In the case of a hydrogen fuel cell, as long as hydrogen and oxygen are supplied, electricity will be generated with water as by-product. Currently, fuel cell applications are limited due to high costs (U.S. DOE, 2006).

Although fuel cells have been included in the IPSP resource assumptions and this analysis, little details were available regarding specific applications in Ontario.

2.10 TRANSMISSION

In order to estimate the potential impacts of new build transmission during the IPSP period, a representative set of transmission options was used. The list of what was evaluated can be found in Appendix A, Table A.8. The range of representative transmission options that were evaluated included new overhead and underground transmission lines, as well as upgrades, refurbishments or replacements of existing facilities, including new and existing termination points (i.e., transformer and switching stations and transmission junctions).

2.11 HYDROELECTRIC IMPORT

The potential exists for an upgrade to the Ontario transmission system to allow new power imports from either Manitoba or Quebec.

Manitoba

Hydroelectric generation for import from Manitoba is assumed to be from Manitoba Hydro's proposed 1250 MW Conawapa Hydroelectric Generating Station on the Nelson River. The transmission requirement for the interconnection for import is from Conawapa in Manitoba to Sudbury. The specific route for the required transmission line has not been determined.

Quebec

Hydroelectric generation for import from Quebec is assumed to be from the La Grande complex. It is assumed that a new transmission right of way for the connection to Quebec would not be required. Other potential sources of power (e.g., Labrador) exist however, the power source has been assumed as La Grande.

3.0 DESCRIPTION OF ENVIRONMENTAL PERFORMANCE CRITERIA

There are many components and subcomponents of the environment that are impacted by electrical generation and transmission. This report draws from the analysis completed in 2005 (SENES, 2005) and builds in additional site-specific information that is now available for the electricity resources.

As per the 2005 report (SENES, 2005), the environmental performance of electricity generation and transmission resources are evaluated using environmental performance criteria factors that are estimated for air emissions, including select conventional contaminants and greenhouse gases, radioactivity releases, land use, water use and wastes production. In this report, all environmental performance criteria are inclusive only of the operation phase of the generation and transmission resources. For an examination of the life cycle impact of different electricity generation options, please see SENES (2005), the study for the OPA Supply Mix Advice Report. This study was based on the available quantitative information, drawn from the relevant literature, and it provided guidance on the relative contributions of the important emissions at each stage (i.e., mining/extraction, construction, operations and decommissioning) of the total life cycle for each of the generation options. This life cycle review shows that the emissions related to each of the stages vary but that in many cases, the operations phase of a generating station is generally dominant. For the IPSP, this report has focused on the emissions related to the operations phase of the generating facility for three reasons: direct relevance to the Ontario specific context; availability of relevant data for application to the Ontario specific context; and data are not available for Ontario specific emissions for the full life cycle stages for each of the generation options. Based on review of the state-of the art on the subject of life cycle assessments (Spath *et.al* 1999, Spath and Mann 2000 and WEC 2004), it can be concluded that the proportion of emissions and impacts arising from the plant operations phase (as opposed to upstream or downstream stages) provide a sufficiently strong indicator of the relative environmental impacts arising from each of the options. As such, in this report no effects associated with life-cycle components except operations are considered, including facility construction and decommissioning and the upstream fuel cycle (extraction, processing and transport).

The environmental performance criteria factors, hereafter referred to as criteria factors, are the data that represent the actual rates of conventional contaminant and greenhouse gas (GHG) emissions to air, radioactivity releases, land and water use and wastes produced. These data have been developed for electricity resources using Ontario-specific facility information, where available, and are generally based on publicly reported emissions, releases, uses, waste production and electricity production information for the facilities. In cases where publicly

reported Ontario data are not available, data representing a particular technology has been drawn from other published sources or mapping software. In particular, air emission data for natural gas electrical generation has been estimated using U.S. EPA emission factors (2000) which is the most representative data currently available.

Where they are required, electricity production rates for all Ontario facilities have been obtained from the Independent Electricity System Operator (IESO) monthly generator reports (2007). The generator reports for each month throughout 2005 have been summed together to calculate a total electricity production for 2005 for all reporting Ontario facilities.

For the criteria factors that have no value estimated for them, the following terms are defined.

0 – a value of zero is reported in cases where the factor is not applicable for technological reasons such as for flow through water use at a cooling tower or air cooled station.

No Data – no data is reported in cases where information was not available but for which the value is assumed not to be zero.

Negligible – negligible is reported in cases where the actual value is expected to be small, particularly in comparison to other reported values, but is not necessarily zero.

Table 3.1 summarizes the set of consolidated data for all of the criteria factors for each electrical resource option that is included in this report. More information with respect to data assumptions and sources is found in the remainder of this Chapter. All applicable assumptions associated with a criteria factor value are presented in the appropriate section of this Chapter.

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TABLE 3.1
CONSOLIDATED CRITERIA FACTORS

Electricity Resource	Generation Style/Station		Fuel	Cooling Water System	Air							Radioactivity (person SV/Gwa)	Land Use (ha/MW)	Water Use		Solid Wastes (T/MWh)
					Conventional (kg/MWh)				GHG (T/MWh)							
					NO_X	SO_2	PM	Mercury	CO_2	CH_4 (CO_2 eq)	N_2O (CO_2 eq)			Flow Through (m^3/MWh)	Consumption (m^3/MWh)	
Fossil	Lennox		Natural Gas/Oil	Once-through	1.24	1.85	0.00100	No Data	0.728	0.000202	0.00206	0.0300	0.0832	73.6	5.08	Negligible
	CHP - Electrical Output (Total Energy Output)		Natural Gas	ACC	0.305 (0.216)	0.0105 (0.00740)	0.0204 (0.0144)	Negligible (Negligible)	0.339 (0.240)	0.000557 (0.00393)	0.00287 (0.00202)		0.0139	0	0.404	
				Cooling Tower										0	No Data	
				Once-through										104	0.404	
	Combined Cycle		Natural Gas	ACC	0.274	0.00941	0.0183	Negligible	0.304	0.000500	0.00257			0	0.0270	
				Cooling Tower										0	No Data	
				Once-through										104	0.0229	
	Single Cycle		Natural Gas	ACC	0.395	0.0136	0.0263	Negligible	0.439	0.000721	0.00371			0	0.0270	
				Cooling Tower										0	No Data	
				Once-through										104	0.0229	
	Average of ON Plants		Coal	Once-through	1.70	4.02	0.0687	0.0000236	1.05	0.000232	0.00465	0.500	0.430	73.6	5.08	0.0162
	IGCC		Coal	ACC	0.363	0.318	0.0635	0.0000204	0.798	No Data	No Data		0.421	0	3.50	0.0794
				Cooling Tower												
				Once-through										73.6	5.08	
Biomass	Average of ON Plants		Wood Waste	Once-through	1.60	0.145	0.104	Negligible	0.32	0.000528	0.0119	Negligible	0.909	Same as Coal	Same as Coal	0.0000109
Nuclear	Ontario Stations		Uranium	Once-through	0.00297	0.00660	0.000407	0.00000000201	Negligible	Negligible	Negligible	2.42	0.166	166	0.332	0.0000753
Hydroelectric	Peaking Small (<20MW)		Water	N/A	Negligible	Negligible	Negligible	Negligible	Negligible	Negligible	Negligible	Negligible	20.3	50000	Negligible	Negligible
	Peaking Medium (21-200MW)		Water	N/A										20000	Negligible	
	Peaking Large (>201MW)		Water	N/A										12000	Negligible	
	Baseload Small (<20MW)		Water	N/A									1.25	50000	Negligible	
	Baseload Medium (21-200MW)		Water	N/A										20000	Negligible	
	Baseload Large (>201MW)		Water	N/A										12000	Negligible	
	Pumped Storage Small (<20MW)	Open	Water	N/A									25.0	50000	Negligible	
		Closed												Negligible	Negligible	
	Pumped Storage Medium (21-200MW)	Open	Water	N/A										20000	Negligible	
		Closed												Negligible	Negligible	
	Pumped Storage Large (>201MW)	Open	Water	N/A										12000	Negligible	
		Closed												Negligible	Negligible	

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TABLE 3.1 (Cont'd)
CONSOLIDATED CRITERIA FACTORS

Electricity Resource	Generation Style/Station		Fuel	Cooling Water System	Air							Radioactivity (person SV/Gwa)	Land Use (ha/MW)	Water Use		Solid Wastes (T/MWh)
					Conventional (kg/MWh)				GHG (T/MWh)							
					NO_X	SO_2	PM	Mercury	CO_2	CH_4 (CO_2 eq)	N_2O (CO_2 eq)			Flow Through (m^3/MWh)	Consumption (m^3/MWh)	
Wind	Average of ON Sites		Wind	N/A	0	0	0	0	0	0	0	0	36.0	0	Negligible	Negligible
Photovoltaic			Solar	N/A	0	0	0	0	0	0	0	0	Negligible	0	0	0
Fuel Cells			Hydrogen	N/A	Negligible	Negligible	Negligible	Negligible	Negligible	Negligible	Negligible	Negligible	Negligible	0	0	Negligible
Transmission Other	Newbuild		N/A	N/A	0	0	0	0	0	0	0	Negligible	9515 ha	0	0	Negligible
Hydroelectric Import	Manitoba	Hydro Large (>201MW)	Water	N/A	Negligible	Negligible	Negligible	Negligible	Negligible	Negligible	Negligible	Negligible	0.400	12000	Negligible	Negligible
		Transmission	N/A	N/A	0	0	0	0	0	0	0	Negligible	5600 ha	0	0	Negligible
	Quebec	Hydro Large (>201MW)	Water	N/A	Negligible	Negligible	Negligible	Negligible	Negligible	Negligible	Negligible	Negligible	96.1	12000	Negligible	Negligible
		Transmission	N/A	N/A	0	0	0	0	0	0	0	Negligible	0 ha	0	0	Negligible
Total Transmission	Newbuild		N/A	N/A	0	0	0	0	0	0	0	Negligible	15115 ha	0	0	Negligible

All associated assumptions are found in sections 3.1 through 3.5

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3.1 AIR

Air emissions are an important environmental consideration for every generation option except some forms of renewable generation such as wind and photovoltaic. Because air emissions are generally a result of ongoing plant operations, the amount (in kilograms or tonnes) of emissions to the air per megawatt-hour is an appropriate metric for comparative analyses across resources and time scales. Air emissions from generation resources are divided into two sub-criteria according to their potential for effects on the natural environment or human health: conventional contaminants and greenhouse gases (GHG).

3.1.1 Conventional Contaminant Air Emissions

Conventional contaminant air emissions are expressed in kilograms per megawatt-hour (kg/MWh). This criterion considers emissions of four potential contaminants: nitrogen oxides (NO_x), sulphur dioxide (SO_2), fine particulate matter (PM) and mercury. SENES (2005) also considered particulate matter less than 10μm (PM_{10}) and formaldehyde and benzene as hazardous air pollutants. In this report, focus was on $PM_{2.5}$ emissions to eliminate the possibility of double counting and to account for the more restrictive regulations on $PM_{2.5}$; however, in some cases PM_{10} has been reported. Formaldehyde and benzene emissions were not included in the method presented in this report because the data set for these two substances was not complete for all electricity generation options. However, available formaldehyde and benzene emissions are presented in the complete raw data set found in Appendix A (Table A.1).

It is recommended that the final reporting of conventional contaminant air emissions include not only the four contaminants individually, but also an index that captures all four components, weighted according to their associated ambient air quality standard (see Section 4.2.1).

Conventional contaminant air emission information was either estimated using the emission factors reported by the U.S. EPA (2000) (natural gas generation options) or obtained from emissions data reported to the National Pollutant Release Inventory (NPRI, 2007). Criteria factors calculated using emission factors from the U.S. EPA were calculated using assumptions provided by the OPA according to those used in the IPSP. Note that in all cases where U.S. EPA emission factors are used, values for PM represent values for PM_{10}. Data available on NPRI are total annual emissions reported by the respective companies as required under the *Canadian Environmental Protection Act*. All NPRI information in this report has been obtained from the on-line database for the 2005 reporting year. Energy production data for 2005 was obtained from the IESO (2007).

Natural Gas

Lennox Generating Station

Data is as reported in NPRI (2007) and IESO (2007) rather than calculated as the other natural gas generation styles. The criteria factor is presented in Tables 3.1 and 3.2 and raw data used for the calculation are presented in Appendix A, Table A.1.

Combined Heat and Power

Conventional contaminant emissions for natural gas CHP have been estimated using the emission rates reported by the U.S. EPA (2000) for natural gas fired stationary gas turbines to determine an estimated emissions rate per MWh. Criteria factors were calculated using an OPA assumed heat rate of 6800 btu/kWh for electrical output only and an estimated heat rate of 4800 btu/kWh for total energy output (Shipley *et. al.* 2001). Electrical output represents emissions attributed to electricity production whereas total energy output accounts for the generation of heat from the use of steam thereby accounting for the additional energy that is generated. In choosing the applicable emission rate from U.S. EPA (2000) for NO_X, the lean premix value was chosen as being representative of low NO_X and inclusive of the NO_X technology typically found installed at Ontario CHP facilities, namely selective catalytic reduction (SCR) or Dry-Low NO_X. It was also assumed that this NO_X lean premix emission rate would be most representative of future CHP stations built in Ontario. The default value for the SO_2 emission rate was assumed representative of natural gas used in Ontario CHP stations. Note that U.S. EPA (2000) does not provide an emission rate for mercury and thus, the value has been assumed negligible. Estimated criteria factors are presented in Tables 3.1 and 3.2. Raw data used for the calculation of all criteria factors is presented in Appendix A, Table A.1.

In addition to these criteria factors, eleven Ontario CHP stations have reported in both NPRI (2007) and IESO (2007). This data and estimated criteria factors are provided for comparison with those calculated using U.S. EPA (2000) emission rates in Appendix A, Tables A.1 and A.2.

Combined Cycle Gas Turbines

Conventional contaminant emissions for CCGT have been estimated using emission rates reported by the U.S. EPA (2000) to determine an estimated emissions rate per MWh. Criteria factors were calculated using an OPA estimated heat rate of 6100 btu/kWh. The default value for the SO_2 emission rate was assumed representative of natural gas used in Ontario CCGT stations. Note that U.S. EPA (2000) does not provide an emission rate for mercury and thus, the value has been assumed negligible. Criteria factors are presented in Tables 3.1 and 3.2. Raw data used for the calculation of all criteria factors is presented in Appendix A, Table A.1.

In addition to these criteria factors, data for Brighton Beach Power Station as reported in NPRI (2007) and IESO (2007) is provided for comparison in Appendix A, Tables A.1 and A.2.

Single Cycle Gas Turbines

Conventional emissions for SCGT are estimated using the emission factors reported by the U.S. EPA (2000) and an OPA estimated heat rate of 8800 btu/kWh. The default value for the SO_2 emission rate was assumed representative of natural gas used in Ontario CCGT stations. Note that U.S. EPA (2000) does not provide an emission rate for mercury and thus, the value has been assumed negligible. The criteria factors are presented in Tables 3.1 and 3.2 and raw data used for the calculation are presented in Appendix A, Table A.1.

Coal

Conventional Coal

The coal emissions and electricity production data are an average of data for the four Ontario stations as reported on NPRI (2007) and IESO (2007). The factor values are presented in Tables 3.1 and 3.2 and raw data used for the calculation are presented in Appendix A, Table A.1. For comparison purposes, U.S. EPA (1998) emission rates for pulverized bituminous and subbituminous coal were used to calculate estimated criteria factors based on Low NO_X technology with and without post burner control as well as with and without SO_2 control at an assumed efficiency of 35%. This data is presented in Appendix A, Table A.1 while the comparison is presented in Table A.2.

IGCC

Conventional emissions for IGCC are obtained from Ratafia-Brown *et al.* (2002). Criteria factors have been converted from pounds per MWh as they are reported in the paper. Note that the paper reports a value for PM_{10}. The criteria factors are presented in Tables 3.1 and 3.2 and raw data used for the calculation are presented in Appendix A, Table A.1.

Biomass

The biomass emissions and electricity production data are an average of data as reported on NPRI (2007) and IESO (2007). Both NO_X and PM criteria factors are an average of Calstock, Cochrane and Kirkland Lake Generating Stations while SO_2 is as provided for Calstock. Note that no mercury emissions are reported for any of these stations on NPRI (2007) however, it is assumed that the biomass fuel source would not contain a natural or anthropogenic source of mercury beyond background levels. As such, the level of mercury in biomass production is

assumed to be negligible. The criteria factors are presented in Tables 3.1 and 3.2 and raw data used for the calculations are presented in Appendix A, Table A.1.

For comparison purposes, emission rates from U.S. EPA (2003 and 2000) for dry and wet wood as well as biogas for landfill and digester gas were estimated using heat rate assumptions from the OPA. These criteria factors are presented in Appendix A, Tables A.1 and A.2.

Nuclear

All conventional contaminant emissions associated with nuclear energy production are associated with back-up and auxiliary systems. The nuclear emissions and electricity production data are an average of data as reported on NPRI (2007) and IESO (2007) for Ontario stations. Both NO_X and PM criteria factors represent an average of Bruce Power and Darlington; SO_2 is an average of Bruce, Darlington and Pickering; and mercury is an average of Darlington and Pickering. The criteria factors are presented in Tables 3.1 and 3.2 and raw data used for the calculation are presented in Appendix A, Table A.1.

For comparison purposes, Tables A.1 and A.2 in Appendix A present estimated criteria factors as calculated from emission rates estimated by Golder (2006) for Pickering Nuclear. These emission rates are based on U.S. EPA and Manufacturer emission data for all emission sources located on the Pickering site.

Hydroelectric

Conventional emissions from hydroelectric peaking, baseload and pumped storage stations are assumed to be negligible. This estimate does not account for flooding associated with ongoing operation.

Wind

Conventional emissions from wind generation are assumed to be negligible.

Photovoltaic

Conventional emissions from photovoltaic electrical generation are assumed to be negligible.

Fuel Cells

Conventional air emissions from fuel cells are assumed to be negligible.

Transmission

Conventional emissions from transmission resources are assumed to be negligible.

Hydroelectric Import

Conventional emissions from hydroelectric import from either Manitoba or Quebec are assumed to be negligible.

TABLE 3.2
CONTAMINANT EMISSION FACTOR VALUES

Electricity Resource	Generation Style/Station		Fuel	Conventional Contaminant Emission Factors (kg/MWh)			
				NO_X	SO_2	PM	Mercury
Fossil	Lennox[a]		Natural Gas/Oil	1.24	1.85	0.00100[7]	No Data
	CHP - Electrical Output (Total Energy Output)[b]		Natural Gas	0.305[1] (0.216[1])	0.0105 (0.00740)	0.0204[2] (0.0144[2])	Negligible
	CCGT[b]		Natural Gas	0.274[1]	0.00941	0.0183[2]	Negligible
	SCGT[b]		Natural Gas	0.395[1]	0.0136	0.0263[2]	Negligible
	Average of ON Plants[a]		Coal	1.70	4.02	0.0687[7]	0.0000236
	IGCC[c]		Coal	0.363	0.318	0.0635	0.0000204
Biomass	Average of ON Plants[a]		Wood Waste	1.60	0.145[3]	0.104[4]	Negligible
Nuclear	Ontario Stations[a]		Uranium	0.00297[5]	0.00660	0.000407[5]	0.00000000201[6]
Hydroelectric	Peaking		Water	Negligible	Negligible	Negligible	Negligible
	Baseload		Water				
	Pumped Storage		Water				
Wind	Average of ON Sites		Wind	0	0	0	0
Photovoltaic			Solar	0	0	0	0
Fuel Cells			Hydrogen	Negligible	Negligible	Negligible	Negligible
Transmission			N/A	0	0	0	0
Hydroelectric Import	Manitoba	Hydro	Water	Negligible	Negligible	Negligible	Negligible
		Transmission	N/A				
	Quebec	Hydro	Water	Negligible	Negligible	Negligible	Negligible
		Transmission	N/A				

Sources: [a]NPRI (2007) and IESO (2007); [b]U.S. EPA (2000); [c]Ratafia-Brown *et al.* 2002.
[1]Assumed lean premix emission rate.
[2]Estimated using emission rate for PM_{10}.
[3]Value is for Calstock Power Plant.
[4]Estimate is actually for PM_{10}.
[5]Value is average of Bruce and Darlington
[6]Value is average of Darlington and Pickering
[7]Value is for $PM_{2.5}$.

3.1.2 Greenhouse Gas Emissions

Greenhouse gas (GHG) emissions are expressed in terms of tonnes per megawatt-hour (T/MWh). This criterion includes three primary greenhouse gas emissions: carbon dioxide (CO_2), methane (CH_4) and nitrous oxide (N_2O), each weighted for their 100-year global warming potential (GWP)[1] and therefore reported as CO_2 equivalents. Where necessary, conversion to the 100-year global warming potential was made using the conversion factors presented in Table 3.3 (EC, 2006). Although not directly related to immediate potential health effects, GHG emissions are of great interest and it is considered important to include them in a comparative evaluation of alternative energy technologies.

TABLE 3.3
GLOBAL WARMING POTENTIAL

GHG	Formula	100-year GWP[1]
Carbon dioxide	CO_2	1
Methane	CH_4	21
Nitrous oxide	N_2O	310

GHG emission information was obtained either from the Environment Canada (EC, 2007) on-line database of facility reported GHGs or estimated using the emission rates reported by the U.S. EPA (2000). The EC program requires all facilities in Canada that emit greater than 100,000 tonnes of CO_2 equivalent units per year to submit a report. This data is compiled and searchable on the EC website. All EC data used in this report is for the 2005 reporting year. Facility energy production for 2005 was obtained from IESO (2007). Criteria factors calculated using emission factors from the U.S. EPA (2000) were calculated according to assumptions provided by the OPA.

Natural Gas

Lennox Generating Station

Data is as reported on EC (2007) and IESO (2007). The criteria factor value is presented in Tables 3.1 and 3.4 and raw data used for the calculation are presented in Appendix A, Table A.3.

[1] GWP is a relative measure of the ability of one GHG to trap heat in the atmosphere relative to another GHG on a unit mass basis over a specified time period. The measure takes into account both the instantaneous and lifetime radiative forcing of the specified gas (EC, 2006).

Combined Heat and Power

GHG emissions for natural gas CHP have been estimated using the emission rate reported by the U.S. EPA (2000) to determine an estimated emission per MWh. Criteria factors were calculated using an estimated heat rate of 6800 btu/kWh for electrical output only and an estimated heat rate of 4800 btu/kWh for total energy output according to OPA assumptions. Criteria factors are presented in Tables 3.1 and 3.4. Raw data used for the calculation of all criteria factors is presented in Appendix A, Table A.2.

In addition to these criteria factors, eleven CHP stations have reported in both EC (2007) and IESO (2007). This additional data and the associated criteria factors are provided in Appendix A, Tables A.3 and A.4.

Combined Cycle Gas Turbine

GHG emissions for natural gas fired CCGT have been estimated using emission rates reported by the U.S. EPA (2000) to determine an estimated emission per MWh. Criteria factors were calculated using an OPA estimated heat rate of 6100 btu/kWh. Criteria factors are presented in Tables 3.1 and 3.4. Raw data used for the calculation of all criteria factors is presented in Appendix A, Table A.3.

In addition to these criteria factors, data for Brighton Beach Power Station as reported on EC (2007) and IESO (2007) was used to calculate estimated criteria factors for comparison to those available from the U.S. EPA (2000). These criteria factors are presented in Appendix A, Tables A.3 and A.4.

Single Cycle Gas Turbine

GHG emissions have been estimated using the emission factors reported by the U.S. EPA (2000) and an OPA estimated heat rate of 8800 btu/kWh. The criteria factors are presented in Tables 3.1 and 3.4 and raw data used for the calculation are presented in Appendix A Table, A.3.

Coal

Conventional Coal

The coal criteria factors are based on the average of reported GHG emissions on EC (2007) and energy production information provided by the IESO (2007) for all Ontario coal fired stations currently in operation. The criteria factors are presented in Tables 3.1 and 3.4 and raw data used for the calculation are presented in Appendix A, Table A.3.

For comparison purposes, emission rates from the U.S. EPA (1998) for pulverized coal were used to calculate GHG criteria factors. These criteria factors are presented in Appendix A, Tables A.3 and A.4.

IGCC

GHG emissions are based on Ratafia-Brown *et al.* (2002) however; no value is reported for CH_4 or N_2O. The criteria factors are presented in Tables 3.1 and 3.4 and raw data used for the calculation are presented in Appendix A, Table A.3.

Biomass

The biomass emission factors are an average of data as reported on EC (2007) and IESO (2007) for the Cochrane and Kirkland Lake Generating Stations. Both stations use wood waste as a fuel source. The criteria factors are presented in Tables 3.1 and 3.4 and raw data used for the calculation are presented in Appendix A, Table A.3. Note that no discount has been made for wood regrowth.

For comparison purposes, emission rates from U.S. EPA (2003 and 2000) for dry and wet wood as well as biogas for landfill and digester gas were estimated using heat rate assumptions from the OPA. These criteria factors are presented in Appendix A, Tables A.3 and A.4.

Nuclear

Greenhouse gas emissions from nuclear power are assumed to be negligible because all associated emissions are from auxiliary or back-up sources. GHG emissions from Ontario's nuclear power plants are not reported on EC (2007) because the facilities emit fewer GHGs than the reporting thresholds.

Hydroelectric

Greenhouse gas emissions from hydroelectric peaking, baseload and pumped storage stations are assumed to be negligible.

Wind

Greenhouse gas emissions from wind generation are assumed to be negligible.

Photovoltaic

Greenhouse gas emissions from photovoltaic electrical generation are assumed to be negligible.

Fuel Cells

Greenhouse gas emissions from fuel cells are assumed to be negligible.

Transmission

Greenhouse gas emissions from transmission resources are assumed to be negligible.

Hydroelectric Import

Greenhouse gas emissions from hydroelectric import from either Manitoba or Quebec are assumed to be negligible.

TABLE 3.4
GREENHOUSE GAS EMISSION FACTOR VALUES

Electricity Resource	Generation Style/Station		Fuel	GHG (T/MWh)		
				CO_2	CH_4 (in CO_2 eq)	N_2O (in CO_2 eq)
Fossil	Lennox[a]		Natural Gas/Oil	0.728	0.000202	0.00206
	CHP - Electrical Output (Total Energy Output)[b]		Natural Gas	0.339 (0.240)	0.000557 (0.000393)	0.00287 (0.00202)
	CCGT[b]		Natural Gas	0.304	0.000500	0.00257
	SCGT[b]		Natural Gas	0.439	0.000721	0.00371
	Average of ON Plants[a]		Coal	1.05	0.000232	0.00465
	IGCC[c]		Coal	0.798	No Data	No Data
Biomass	Average of ON Plants[a]		Wood Waste	0.320	0.000528	0.0119
Nuclear	Ontario Stations		Uranium	Negligible	Negligible	Negligible
Hydroelectric	Peaking		Water	Negligible	Negligible	Negligible
	Baseload		Water			
	Pumped Storage		Water			
Wind	Average of ON Sites		Wind	0	0	0
Photovoltaic			Solar	0	0	0
Fuel Cells			Hydrogen	Negligible	Negligible	Negligible
Transmission			N/A	0	0	0
Hydroelectric Import	Manitoba	Hydro	Water	Negligible	Negligible	Negligible
		Transmission	N/A			
	Quebec	Hydro	Water	Negligible	Negligible	Negligible
		Transmission	N/A			

Sources: [a]EC (2007) and IESO (2007); [b]U.S. EPA (2000); [c]Ratafia-Brown *et al.* 2002.

3.2 Radioactivity

Radioactivity releases are expressed in terms of their normalized collective effective dose in person Sieverts per gigawatt-annum (person Sv/GWa). This criterion considers all radiological effects on a local population resulting from airborne and liquid effluent releases from normal power plant operations.

Various radionuclides are released from nuclear, coal and natural gas fuel cycle activities. The radionuclides released vary by type of fuel and, in the case of nuclear, by type of reactor and from reactor to reactor. Sources include such species as noble gases, radioactive particulates and tritium. Fortunately, well accepted methods exist for converting exposure to any radionuclide to a common unit, namely dose (see for example UNSCEAR, 2000). Radioactive emissions and normalized collective doses are as reported in UNSCEAR (1993 and 2000).

In UNSCEAR (1993 and 2000) and this report, radioactivity releases are reported as the total of airborne and liquid effluent releases.

Natural Gas

Radioactivity from generating stations using natural gas is estimated from UNSCEAR (1993), which presents an operation number that will be conservatively high because it does not account for any radioactive decay during transfer and storage. The criteria factor is presented in Tables 3.1 and 3.5.

Coal

Depending on its source, coal contains varying amounts of inorganic matter including trace elements and radionuclides. During coal combustion, most of these elements are released and distributed between the gas phase and solid combustion products depending on the volatility of each element. Most radon is released in its gas phase as part of the stack emissions. As the less volatile elements decay, including uranium and thorium, air emissions of radioactivity are also released. Some of the radioactivity will also remain in the furnace bottom ash. Radioactivity from generating stations using coal for fuel is estimated from UNSCEAR (1993) and is presented in Tables 3.1 and 3.5.

Biomass

Biomass radioactivity in this report is reported as negligible. Although it is unlikely that the normalized collective dose of radioactivity from biomass combustion would be high, it is possible that it is not zero. However, no specific data is readily available for Ontario, or

otherwise, regarding the normalized collective dose from the operation of a biomass generating station.

Nuclear

The radioactivity emission rates and collective effective dose for nuclear generation is obtained from UNSCEAR (2000). All reactors currently in use in Ontario are heavy water reactors while the most common used in the other parts of the world are pressurized water reactors. The largest difference between the two is the release of tritium which is higher for heavy water reactors. Radioactivity associated with nuclear power generation is presented in Tables 3.1 and 3.5.

Hydroelectric

Radioactivity from hydroelectric peaking, baseload and pumped storage stations is assumed to be negligible.

Wind

Radioactivity from the operation of wind generating stations is assumed to be zero.

Photovoltaic

Radioactivity from the operation of photovoltaic generating stations is assumed to be zero.

Fuel Cells

Radioactivity from the operation of fuel cells is assumed to be negligible.

Transmission

Radioactivity from transmission options is assumed to be negligible.

Hydroelectric Import

Radioactivity from hydroelectric import from either Manitoba or Quebec is assumed to be negligible.

TABLE 3.5
RADIOACTIVITY: NORMALIZED COLLECTIVE EFFECTIVE DOSE (PERSON Sv/GWa)

Electricity Resource	Generation Style/Station		Fuel	Radioactivity (person SV/Gwa)
Fossil	Lennox		Natural Gas/Oil	0.0300[a]
	CHP		Natural Gas	
	CCGT		Natural Gas	
	SCGT		Natural Gas	
	Average of ON Plants		Coal	0.500[a]
	IGCC		Coal	
Biomass	Average of ON Plants		Wood Waste	Negligible
Nuclear	Ontario Stations[b]		Uranium	2.42
Hydroelectric	Peaking		Hydro	Negligible
	Baseload		Hydro	
	Pumped Storage		Hydro	
Wind	Average of ON Sites		Wind	0
Photovoltaic			Solar	0
Fuel Cells			Natural Gas	Negligible
Transmission			N/A	Negligible
Hydroelectric Import	Manitoba	Hydro	Water	Negligible
		Transmission	N/A	
	Quebec	Hydro	Water	Negligible
		Transmission	N/A	

Sources: [a]UNSCEAR (1993) [b]UNSCEAR (2000).

3.3 LAND USE

This criterion is intended to provide an indication of the amount of land used by electricity resources in the IPSP and is an important consideration for all generation and transmission resources with the exception of fuel cells and photovoltaic systems. The land use estimation includes the area required for the footprint of the facility or transmission line and associated components, including buffer zones or exclusion areas. The amount of land used is a function of construction and ongoing presence of the facility and therefore the area per megawatt (MW), rather than per megawatt-hour, is the more appropriate metric. Because the impact on land is a one time occurrence, there are no incremental increases in potential effects as the facility produces or transmits electricity. Transmission land use is expressed solely as area; no attempt was made to estimate the MW of production associated with a particular transmission line.

This analysis does not consider the possible retirement of generating stations or transmission lines. Once a station or transmission line is retired it becomes a brownfield site that may be reused for power generation or transmission or may be cleaned up for another use. These sites generally do not return to their pre-development quality.

Natural Gas

Lennox Generating Station

Land use for the Lennox Generating Station has been estimated as 178 hectares using Google Earth (2007). The criteria factors are presented in Tables 3.1 and 3.6 and raw data used for the calculation are presented in Appendix A, Table A.5.

CHP, Combined Cycle and Single Cycle Gas Turbines

Land use for CHP, CCGT and SCGT natural gas generation has been estimated as an average of land area required for the proposed Thorold CHP plant to be developed on a pulp and paper mill site in Thorold Ontario, for the Brighton Beach plant in Windsor and for Portlands Energy Centre in Toronto. Area for the Thorold CHP plant was estimated using Google Earth (2007) while land area for Brighton Beach and PEC are obtained from ATCO (2001) and PEC (2003), respectively. The criteria factor is presented in Tables 3.1 and 3.6 and raw data used for the calculation are presented in Appendix A, Table A.5.

Coal

Conventional Coal

The land use factor for coal is an average of Ontario's existing coal-fired power plant land areas and station capacity found in station overview brochures for Atikokan (OPG, 2007a), Lambton (OPG, 2007b), Nanticoke (OPG, 2007c), and Thunder Bay (OPG, 2007d). The criteria factors are presented in Tables 3.1 and 3.6 and raw data used for the calculation are presented in Appendix A, Table A.5.

IGCC

Land use is estimated using values for the Mesaba Energy Project (U.S. DOE, 2005). This proposed facility is considered a good estimate of what a new coal-fired station would entail with respect to land use in Ontario. It is noted that the plant includes a buffer zone surrounding the actual facility site; the facility site size is estimated as 170 hectares while the total area including

the buffer zone is 1260 hectares (U.S. DOE, 2005). The criteria factors are presented in Tables 3.1 and 3.6 and raw data used for the calculation are presented in Appendix A, Table A.5.

Biomass

Estimates for biomass facility land use have been extrapolated from a proposed project in Saint John, New Brunswick (CEAA, 2005), and for the proposed Minnesota Biomass plant in Waseca County Minnesota (EQB, 2003). Values for biomass generating station land use are presented in Tables 3.1 and 3.6 and raw data used for the calculation are presented in Appendix A, Table A.5. Note that the land use estimate does not include any land requirements for fuel production but does include all associated facilities such as for fuel storage.

Nuclear

Approximate land use estimates are obtained from facility maps for the three nuclear generating stations in Ontario: Darlington (OPG, 2002), Pickering (OPG, 2003) and Bruce (OPG, 2005b). Criteria factors for land use by nuclear generating stations are presented in Tables 3.1 and 3.6 and raw data used for the calculation are presented in Appendix A, Table A.5.

Hydroelectric

For the three types of hydroelectric generation, peaking stations will result in the largest use of land, baseload stations should result in the least and a pumped storage station could result in something close to a peaking station or fall somewhere between the two.

Peaking

Land use for peaking hydroelectric generating stations is based primarily on the size of the reservoir created for the station. Estimates for reservoir size, intake, penstock, powerhouse, associated facilities as well as headpond have been obtained for twelve generating stations in Ontario: four on the Mattagami River (ON Hydro, 1990), Harmon, Kipling, Little Long and Smoky Falls; Red Rock Falls on the Mississagi River (Google Earth, 2006); Kakabeka Falls on the Kaministiquia River (Google Earth, 2006); Pine Portage on the Nipigon River (Google Earth, 2006); two on the Madawaska River, Arnprior (Google Earth, 2006) and Mountain Chute (MRWMR, 2004); and three on the Ottawa River (Google Earth, 2006), Otto Holden, Des Joachims and Chats Falls.

Peaking hydroelectric land use is presented in Tables 3.1 and 3.6 and the raw data used for the calculation are presented in Appendix A, Table A.6.

Baseload

Land use for baseload hydroelectric generating stations is based primarily on the size of the reservoir created for the station and the associated land use for necessary facilities. Estimates for intake, penstock, powerhouse and associated facilities have been obtained for eleven generating stations in Ontario: three on the Mattagami River, Lower Sturgeon, Sandy Falls and Wawaitin; Hound Chute on the Montreal River, three on the South Muskoka River, Hanna Chute, South Falls and Tretheway; Merrickville on the Rideau River; and three on the Trent River, Frankford, Seymour and Sidney (Google Earth, 2006).

Baseload hydroelectric land use is presented in Tables 3.1 and 3.6 and the raw data used for the calculation are presented in Appendix A, Table A.7.

Pumped Storage

Land use for pumped storage generation has been estimated using information about Sir Adam Beck I and II hydroelectric stations developed as part of the Niagara River Hydroelectric Development (ON Hydro, 1991).

Values for pumped storage generation land use are presented in Tables 3.1 and 3.6 and raw data used for the calculation are presented in Appendix A, Table A.5.

Wind

Land use for wind generation in Ontario has been calculated as an average of eleven sites listed on OPA's contracted wind power project website (OPA, 2007a). Sites included in the average are: Erie Shores Wind Farm; Kingsbridge I and II Wind Power Projects; Kruger Energy Port Alma Wind Power Project; Leader A & B Wind Power Projects; Melancthon I and II Wind Projects; Prince I and II Wind Energy Projects; Ripley Wind Power Project; and Wolfe Island Wind Project.

The land use criteria factor for wind generation is presented in Tables 3.1 and 3.6 and raw data used for the calculation are presented in Appendix A, Table A.5. Included in Table A.5 is an average that includes the Wolfe Island Wind Project.

Photovoltaic

In this report, it is assumed that any photovoltaic generation development in Ontario would be integrated into either building roofs or façades and, as such, photovoltaic land use is assumed to be negligible.

Fuel Cells

Land use for fuel cell generation is assumed to be negligible because it is expected that generation will require minimal land use or be installed in existing buildings.

Transmission

Approximate land use for transmission lines has been estimated using line lengths for 20 potential line builds and the required number of right of ways with an assumed transmission right of way width of 35 m. It is noted that the total area reported is an approximation of the new transmission that will be required in Ontario within the period of the IPSP and should only be evaluated as such. Further, no attempt has been made to estimate the appropriate megawatts that should be used to produce a factor for transmission. Instead, transmission land use is reported in total hectares.

Transmission land use is presented in Tables 3.1 and 3.6 and raw data used for the calculation is presented in Appendix A, Tables A.5 and A.8.

Hydroelectric Import

Land use estimates for hydroelectric imports from either Manitoba or Quebec include both those required for the transmission interconnections between Manitoba or Quebec and Ontario and also the land use for the generation station itself, even if that land occurs outside of Ontario.

Generation and land from Manitoba is assumed to be from the proposed Conawapa generating station (MB Hydro, 2007), while that from Quebec is assumed to be from the La Grande Complex (Hydro Quebec, 2007). Transmission line lengths are estimated using the estimated length of the transmission and assuming a ROW width of 35 m. The land use for the transmission and generation has then been added to provide an overall estimate for land use.

The land use for the Manitoba and Quebec hydroelectric import are presented in Tables 3.1 and 3.6 and raw data used for the calculation are presented in Appendix A, Tables A.5 and A.8.

TABLE 3.6
LAND USE

Electricity Resource	Generation Style/Station		Fuel	Land Use (ha/MW)
Fossil	Lennox[a]		Natural Gas/Oil	0.0832
	CHP		Natural Gas	0.0139[b]
	CCGT		Natural Gas	
	SCGT		Natural Gas	
	Average of ON Plants[c]		Coal	0.430
	IGCC[d]		Coal	0.421
Biomass	Average of ON Plants[c]		Wood Waste	0.909
Nuclear	Ontario Stations[e]		Uranium	0.166
Hydroelectric	Peaking[f]		Water	20.3
	Baseload[g]		Water	1.25
	Pumped Storage[h]		Water	25.0
Wind	Average of ON Sites[i]		Wind	36.0
Photovoltaic			Solar	0
Fuel Cells			Hydrogen	Negligible
Other Transmission			N/A	9515 ha[j]
Hydroelectric Import	Manitoba	Hydro	Water	0.400[k]
		Transmission	N/A	5600 ha[j]
	Quebec	Hydro	Water	96.1[l]
		Transmission	N/A	0 ha[j]
Total Transmission			N/A	15115 ha[j]

Source: [a]Google Earth (2007); [b]average of Thorold CHP (Google Earth 2007), Brighton Beach (ATCO 2001) and PEC (PEC 2003); [c]average of Atikokan, Lambton, Nanticoke and Thunder Bay Generating Stations (OPG 2007a, b, c and d); [d]U.S. DOE (2005); [e]average for Darlington, Pickering and Bruce Generating Stations (OPG 2002, 2003 and 2005b); [f]average of twelve Ontario generating stations (ON Hydro 1990, MRWMR 2004 and Google Earth 2006); [g]average of eleven Ontario generating stations (Google Earth 2006); [h]ON Hydro 1991; [i]OPA 2007a; [j]estimated from approximate line lengths and required right of ways; [k]MB Hydro 2007; [l]Hydro Quebec 2007

3.4 WATER USE

This criterion is intended to capture the use – both consumptive and non-consumptive – of water by a generation option. Because the use of water is a direct result of ongoing operations, volume in cubic metres per megawatt-hour is an appropriate metric. Water use is only applicable to generation options and not to transmission options. In this analysis, two water use impacts are considered:

Flow Through – water use defined as that which is returned to the system such as hydroelectric generation and stations with once-through cooling systems. By definition, this water is not consumed and is returned to the system from which it has been drawn with only permitted changes in quality.

Consumption – water use defined as that which is not returned to the system. All electrical generating stations consume some amount of water because it is not only used as make-up water for re-circulating cooling systems but also for general plant operations such as make-up water for the boiler. The amount of consumed water will vary depending on whether steam is also used off-site (such as for CHP) or if consumed water is strictly for boiler make-up water (such as for a thermal station with ACC cooling) or if it is both boiler and closed loop make-up water (such as for a thermal station with a cooling tower).

Water use by a thermal or nuclear generating station is dependant on a number of factors. Of primary importance for generating stations where the water is used for cooling purposes, is the type of cooling water system. All cooling water systems draw water from the ambient water body and then either consume the water as make-up water or use it as cooling water. The difference between cooling water systems comes in how that cooling water is used (Feeley, III *et al.*, 2005). In general, there are two types:

1. Once-through – these systems return the cooling water back to the ambient water body. Generally this water has had some quality alteration such as an increase in temperature.
2. Closed-loop – For any closed-loop system, water is drawn to make-up for evaporative losses in the cooling system, however, these systems re-circulate cooling water in a couple of different ways:
    i. Cooling tower – cooling water is pumped to a cooling tower to allow the excess heat to dissipate before the water is reused.
    ii. Air Cooled Condenser (ACC) – air, typically provided by a large bank of fans (TransCanada, 2007), is used as the cooling medium therefore no water is drawn for the cooling system.

There are other types of closed-loop cooling systems (e.g., pond cooling) however, for purposes of this report, only cooling towers and ACC are considered.

Natural Gas

Lennox Generating Station

Lennox is a once-through generating station and it is likely that flow through and consumption would be similar to that calculated for other thermal stations (i.e., conventional coal) with once-

through cooling. As such, water use data for the Lennox Generating Station is assumed to be the same as that for conventional coal. Water use for Lennox is presented in Tables 3.1 and 3.7.

Combined Heat and Power

Water use flow through for a CHP natural gas plant has been estimated from water use for PEC (2003) when it was proposed as a CHP station with a once-through cooling system. Water consumption for a once-through station has also been estimated based on consumptive water use at PEC (2003). Consumptive water use at PEC in this configuration is for both boiler and steam generation make-up water

It is assumed that consumptive water use for an ACC CHP station would be the same as the consumptive use at a once-through station; that is for boiler and steam generation make-up water. Although both the ACC and cooling tower generation stations would have zero flow through water use, no data is available for consumptive water use at a cooling tower station. The consumptive water use at a cooling tower station would include boiler, steam generation and cooling tower make-up water therefore it is expected to be somewhat larger than that for an ACC or once-through CHP station.

Natural gas CHP water use is presented in Tables 3.1 and 3.7 and raw data used for the calculation is presented in Appendix A, Table A.9.

Combined Cycle and Single Cycle Gas Turbines

Water use flow through for both CCGT and SCGT natural gas fired stations with once-through cooling systems are assumed the same as that from PEC (2003). Consumption water use for a once-through CCGT or SCGT station is assumed the same as water use at the proposed Halton Hills Generating Station without evaporative cooling (TransCanada, 2007); this value is inclusive of only boiler make-up water. Consumption water use for an ACC system is calculated as an average of the estimated consumed water for use with and without evaporative cooling at the proposed Halton Hills Generating Station (TransCanada, 2007); this value is inclusive of boiler make-up water as well as an average usage for the evaporative cooling system. No water use data is available for either CCGT or SCGT stations with a cooling tower which would have additional water use for make-up water for the cooling system and is expected to consume water at a rate greater than that for a once-through or ACC system.

Natural gas CCGT and SCGT water use is presented in Tables 3.1 and 3.7 and raw data used for the calculation is presented in Appendix A, Table A.9.

Coal

Conventional Coal

Ontario coal fired stations operate with once-through cooling systems. Both flow through and consumption water use criteria factors have been calculated for Lambton Generating Station based on station generated values (OPG, 2007e). Flow through and consumption water use is presented in Tables 3.1 and 3.7 and raw data used for the calculation is presented in Appendix A, Table A.8.

IGCC

Waster use for an IGCC station with either ACC or cooling tower cooling water system is estimated from the middle of the range provided in Ratafia-Brown *et al.* (2002). Water use for an IGCC station with once-through cooling is assumed to be the same as that required for conventional coal. Water use is presented in Tables 3.1 and 3.7 and raw data used for the calculation is presented in Appendix A, Table A.9.

Biomass

Although there are biomass generating stations currently operating in Ontario, no water use data from these stations is readily available. As such, for the purposes of this report, biomass water use assumes a once-through cooling water system and the same flow through and consumption water use as a coal fired station. Criteria factors are presented in Tables 3.1 and 3.7.

Nuclear

Water use flow through for a nuclear generating station with once-through cooling is calculated from the average maximum water drawn through the water intake data from Pickering Nuclear (OPG, 2000). Consumption water use is estimated as 0.2% of the flow through value based on information from OPG (2006b). Water use values for flow through and consumption at a nuclear generating station are presented in Tables 3.1 and 3.7 and raw data used for the calculation is presented in Appendix A, Table A.9.

Hydroelectric

Hydroelectric generating stations have large amounts of water flow through the turbines in a given year. Typically, this value is equal to the entire volume of water that passes down the particular system.

However, consumption water use at hydroelectric stations is not a simple matter. Although some consumptive use is expected due to general station operation, such as cleaning, evaporative losses from impounded water could also be considered. Calculation of water loss due to evaporation from reservoirs is dependent not only on the area of the reservoir but also local ambient conditions such as air and water temperature and even wind conditions. This kind of calculation is beyond the scope of this document.

Peaking

Some flow through data for hydroelectric peaking stations has been supplied by OPG (2006a) for 2005 operating data. Values are broken down according to the size of the station. Water use consumption data is assumed to be negligible, but not zero, for all hydroelectric peaking stations. Water use values for flow through and consumption at hydroelectric peaking stations is presented in Tables 3.1 and 3.7 and raw data used for the calculation is presented in Appendix A, Tables A.9 and A.10.

Baseload

Water flow through at baseload hydroelectric stations is assumed the same as for peaking stations. Water use consumption data is assumed to be negligible but not zero for all hydroelectric baseload stations. Water use values for flow through and consumption at hydroelectric baseload stations is presented in Tables 3.1 and 3.7 and raw data used for the calculation is presented in Appendix A, Tables A.9 and A.10.

Pumped Storage

There are two basic styles of pumped storage hydroelectric generating stations, open and closed. An open pumped storage station operates in a similar manner to a peaking station with the exception that during off-peak times, water is pumped into the reservoir for use during peak periods. A closed pumped storage station operates as a closed system with two pools of water that are not hydrologically linked to any other water system, as such, water is cycled between the reservoir and outfall pool during off-peak and peak periods respectively. Water use, both flow through and consumption, at an open pumped storage station is assumed to be the same as for a peaking station. Flow through waster use at a closed pumped storage station is assumed to be negligible since the water is recycled. Consumption water use at a closed pumped storage hydroelectric station is assumed to be the same as all other hydroelectric generating stations, negligible but not zero. Water use values for pumped storage hydroelectric systems is presented in Tables 3.1 and 3.7 and raw data used for the calculation is presented in Appendix A, Tables A.9 and A.10.

Wind

Water use for wind generation is assumed to be zero for both flow through and consumption.

Photovoltaic

Water use for photovoltaic generation is assumed to be zero for both flow through and consumption.

Fuel Cells

It is assumed that a fuel cell generating station would not require cooling water. As such, both flow through and consumption water use are assumed to be zero.

Transmission

Water use for transmission resource options is assumed to be zero for both flow through and consumption.

Hydroelectric Import

Water flow through use for hydroelectric import from either Manitoba or Quebec is assumed to be the same as for large hydroelectric peaking stations greater than 201MW in rated capacity. Further, water use consumption data is assumed to be negligible but not zero. Water use values for flow through and consumption for hydroelectric import are presented in Tables 3.1 and 3.7 and raw data used for the calculation is presented in Appendix A, Tables A.9 and A.10.

TABLE 3.7
WATER USE

Electricity Resource	Generation Style/Station		Fuel	Cooling Water System	Water Use	
					Flow Through (m^3/MWh)	Consumption (m^3/MWh)
Fossil	Lennox		Natural Gas/Oil	Once-through	73.6	5.08
	CHP[a]		Natural Gas	ACC	0	0.404
				Cooling Tower	0	No Data
				Once-through	104	0.404
	CCGT		Natural Gas	ACC	0	0.0270[b]
				Cooling Tower	0	No Data
				Once-through	104[a]	0.0229[b]
	SCGT		Natural Gas	ACC	0	0.0270[b]
				Cooling Tower	0	No Data
				Once-through	104[a]	0.0229[b]
	Average of ON Plants		Coal[c]	Once-through	73.6	5.08
	IGCC		Coal	ACC[d]	0	3.50
				Cooling Tower[d]		
				Once-through[c]	73.6	5.08
Biomass	Average of ON Plants		Wood Waste[c]	Once-through	73.6	5.08
Nuclear	Ontario Stations		Uranium	Once-through	166[e]	0.332[f]
Hydroelectric[g]	Peaking Small (<20MW)		Water	N/A	50000	Negligible
	Peaking Medium (21-200MW)		Water	N/A	20000	Negligible
	Peaking Large (>201MW)		Water	N/A	12000	Negligible
	Baseload Small (<20MW)		Water	N/A	50000	Negligible
	Baseload Medium (21-200MW)		Water	N/A	20000	Negligible
	Baseload Large (>201MW)		Water	N/A	12000	Negligible
	Pumped Storage Small (<20MW)	Open	Water	N/A	50000	Negligible
		Closed			Negligible	
	Pumped Storage Medium (21-200MW)	Open	Water	N/A	20000	Negligible
		Closed			Negligible	
	Pumped Storage Large (>201MW)	Open	Water	N/A	12000	Negligible
		Closed			Negligible	
Wind			Wind	N/A	0	Negligible
Photovoltaic			Solar	N/A	0	0
Fuel Cells			Hydrogen	N/A	0	0
Transmission			N/A	N/A	0	0
Hydroelectric Import[g]	Manitoba	Hydro Large (>201MW)	Water	N/A	12000	Negligible
		Transmission	N/A	N/A	0	0
	Quebec	Hydro Large (>201MW)	Water	N/A	12000	Negligible
		Transmission	N/A	N/A	0	0

Sources: [a]PEC (2003); [b]TransCanada (2007); [c]OPG (2007e); Ratafia-Brown *et al.* (2002); [e]OPG (2000); [f]OPG (2006b);[g]OPG 2006a.

3.5 SOLID WASTES

This criterion is intended to include wastes produced during normal station operations. Solid wastes produced as a result of electrical generation are identified in terms of type and quantity, and expressed as a mass (tonnes) per MWh. Because wastes directly result from operations, production per megawatt hour is an appropriate metric.

When considering wastes generated during the routine operation of thermal power plants, although the technology itself influences the production of waste, it is the type of fuel that determines the type and amount of wastes produced. Conventional solid or chemical wastes such as cans, cardboard, paper, newspaper, plastic, office or cleaning products, metals and glass have not been included in this analysis because they are common to all generating stations.

Solid wastes produced during electrical generation have the potential to constitute a deleterious substance and the potential toxicity of different types of wastes varies. As such, a qualitative comparison of the potential toxicity of wastes produced at nuclear, coal and biomass generating stations is presented in Appendix B, section B.4.2.

Natural Gas

Natural gas, when burned, does not create waste by-products. As such, operational waste for both natural and synthetic gas is determined to be negligible because, although conventional and chemical waste is not quantified in this analysis, it will be produced and it is therefore not accurate to represent natural gas generation as producing zero waste.

Coal

Conventional Coal

Electricity produced from coal produces both fly and bottom ash and in some stations gypsum (from flue gas desulphurization) as wastes. OPG reported in their 2005 Sustainable Development Report (OPG 2005a) that the corporation diverted 62% of recovered ash and gypsum from landfills. OPG sells the recovered fly ash for use in binding materials, bottom ash as roadbed fill material and recycles gypsum for use in manufacturing dry wall. The total amount of ash and gypsum produced in 2005 was 1,286,980 tonnes with 801,913 tonnes recycled and therefore diverted from landfills. This results in just over 485,000 tonnes of waste that must be disposed of in landfills annually. For calculation, the MWh produced at all five Ontario coal stations in operation in 2005 (Lakeview GS was taken out of production in 2005) and reported to the IESO (2007) were summed for a total MWh of coal production of 30,014,479 MWh in 2005.

The waste criteria factor for coal is presented in Tables 3.1 and 3.8 and the raw data used for calculation are presented in Appendix A, Table A.11.

IGCC

Waste production in an IGCC plant primarily consists of a solid slag (char), the production of which is a function of the ash content of the coal that is being burned. This slag can subsequently be recycled for other applications. IGCC generation also produces a second by-product in the form of sulphur or sulphuric acid which is also recyclable for use in other applications. Ratafia-Brown *et al.* (2002) estimate total solid waste generated in pounds per megawatt hour. The waste criteria factor for IGCC is presented in Tables 3.1 and 3.8 and the raw data used for calculation is presented in Appendix A, Table A.11. Note that no effort has been made to estimate the potential for recycling of this waste because it is not currently known if a market will be available for IGCC by-products.

Biomass

Biomass, assuming wood waste as the fuel source, generates ash waste (bottom and fly ashes) as a by-product of combustion. Unfortunately, no Ontario specific information is available regarding waste production at a biomass generating station therefore the biomass waste number estimated in SENES (2005) will be used. In order to estimate the production of waste from a biomass facility, contact was made with the Williams Lake Generating Station in British Columbia (Meyer, 2005). The Williams Lake station uses over 550,000 tons of wood waste from five nearby sawmills to generate 67 to 69 MW of power (over 500,000 MWh per year) and roughly 5.8 tonnes of ash waste.

With respect to the waste generated at the Williams Lake station, there currently is a trial project for local farmers to utilize the ash as a substitute for agricultural lime however, this option has not been fully developed (Meyer, 2005). As such, it is assumed that biomass ash, on a non-site specific basis, will be disposed of in landfills.

The biomass waste criteria factor is presented in Tables 3.1 and 3.8 and the raw data used for calculation is presented in Appendix A, Table A.11.

Nuclear

OPG's *Sustainable Development Report* (2004a) provides the net MWh of electrical production and the quantities of waste by type produced at the Pickering and Darlington nuclear plants in 2004. Solid wastes generated during routine operation at a nuclear power plant include:

- low-level radioactive waste in the form of clothing, mop heads, rags, paper towels and floor sweepings;
- intermediate level waste such as used reactor components, or resins and filters to keep the reactor water systems clean;
- used fuel bundles; and
- hazardous Wastes - liquid and solid.

For the purpose of this report, only the used fuel bundles, and low and intermediate level waste will be considered in the calculation of the criteria factor. The quantity of low and intermediate level waste is presented as a volume (m^3) however, for our purposes an estimate of mass (in tonnes) is required. To estimate the mass, the ratio of intermediate to low level radioactive waste has been obtained from OPG's *Nuclear Waste Management* report (2004b) and then the tonnes of low level radioactive waste are estimated using the density of cardboard and the tonnes of intermediate level radioactive waste are estimated using the density of iron. From the reported 1979 m^3 of low and intermediate level waste from Pickering and Darlington that was stored in 2004 the estimated tonnage is 1958 tonnes.

Waste quantities (as reported for 2004) are presented in Tables 3.1 and 3.8 and the raw data used for calculation is presented in Appendix A, Table A.11.

Hydroelectric

There are no waste products requiring storage or disposal as a result of routine operation of a hydroelectric station, except conventional and chemical waste associated with general facility operations. Therefore, the value for waste from hydroelectric generation is negligible.

Hydroelectric Import

Similar to hydroelectric, no waste products requiring storage or disposal result from the import of power from either Manitoba or Quebec. Therefore the factor value for waste from hydroelectric import is negligible.

Wind

There are no waste products requiring storage or disposal as a result of routine operation of a wind farm. Therefore, the waste factor value for wind generation is assumed to be negligible.

Photovoltaic

There are no waste products requiring storage or disposal as a result of routine operation for photovoltaic generation. Further, it is expected that there would also be no conventional or chemical waste. Therefore, the waste factor value for photovoltaic generation is assumed to be zero.

Transmission

There are no waste products requiring storage or disposal as a result of routine operation of transmission resources. However, there may be waste generated during atypical events such as storms and accidents for wire and/or tower repair. As such, the waste factor for transmission is assumed to be negligible.

TABLE 3.8
WASTES

Electricity Resource	Generation Style/Station		Fuel	Solid Wastes Generated (T/MWh)
Fossil	Lennox		Natural Gas/Oil	Negligible
	Cogeneration		Natural Gas	
	Combined Cycle		Natural Gas	
	Single Cycle		Natural Gas	
	Average of ON Plants[a]		Coal	0.0162
	IGCC[b]		Coal	0.0794
Biomass[c]			Wood Waste	0.0000109
Nuclear[a and d]	Ontario Stations		Uranium	0.0000753
Hydroelectric	Peaking		Water	Negligible
	Baseload		Water	
	Pumped Storage		Water	
Wind			Wind	Negligible
Photovoltaic			Solar	0
Fuel Cells			Hydrogen	Negligible
Transmission			N/A	Negligible
Hydroelectric Import	Manitoba	Hydro	Water	Negligible
		Transmission	N/A	
	Quebec	Hydro	Water	
		Transmission	N/A	

Sources: [a]OPG (2005a) and IESO (2007); [b]Ratafia-Brown *et al.* (2002); [c]Meyer (2005); [d]OPG (2004b);

3.6 RESOURCE AVAILABILITY

The 2005 SENES report contained a seventh environmental criterion called sustainability. That criterion assessed the years of production remaining for finite resources such as coal and uranium. This report did not retain that criterion for evaluation purposes, but the reader is referred to the discussion of sustainability as a function of remaining fuel production as reported in SENES (2005).

4.0 RECOMMENDATIONS FOR FACTOR AND MODIFIER USE

The information presented in the previous chapters results in a set of criteria factors that can be used to indicate the environmental performance of an electricity resource mix, which can then be used to describe differences between the current mix in Ontario and that of the Integrated Power System Plan (IPSP) when fully implemented. Alternatives, such as sequential iterations of the Plan can also be assessed. Table B.1 in Appendix B summarizes the set of consolidated data for all of the criteria factors for each electrical resource option that is included in this report.

This chapter outlines how to use the criteria factors. As part of this methodology, a set of modifiers were developed that may be applied to describe the environmental performance at the level of the electricity system. Modifiers allow for some degree of analysis of the overall potential to cause impacts to the natural environment in more qualitative terms. Modifier description and usage instructions are provided in Appendix B. The overall methodology is intended to compliment the suite of sustainability criteria described in the OPA's Discussion Paper on Sustainability (#6) of the IPSP.

4.1 APPLICATION OF CRITERIA FACTORS

This methodology was developed to be easily applied to different electrical resource options as well as supply option mixes. The criteria factors are intended to represent the best available information regarding the quantitative environmental performance of electrical generation and transmission on the natural environment.

The radioactivity, water use, land use and waste environmental criteria factors can also be applied to new technologies where impacts are expected to be similar. For example, it can be assumed that all CANDU nuclear stations with once-through cooling will circulate roughly 166 m^3/MWh of flow through water regardless of whether they represent new or old technology. If new information is known for new or upgraded technologies, then the values used for the criteria factors can be updated. The values for conventional contaminants and GHG air emissions may not substitute as well to new technologies which may have improved emission controls or more efficient operation. As such, caution should be exercised if using existing values as proxies for new technologies or resources, and such values should be updated with new information as it becomes available.

The following discussion is a general methodology to use these criteria factors to estimate and compare the natural environment impacts associated with different electrical resource options and/or different supply mix options:

4.1.1 Air

4.1.1.1 Conventional Contaminant Air Emissions

These emissions are reported in terms of mass of emissions per MWh (kg/MWh) and if the electricity production is known (MWh/yr), then by applying this method final values are calculated and expressed as a total mass per year. Emissions for each conventional contaminant can be estimated for each electrical resource comprising the electrical system as follows:

Conventional Emissions (kg/year) = Emission rate (kg/MWh) * Electricity production (MWh/yr)

where emission rate is the criteria factor estimated for each conventional contaminant (NO_x, SO_2, PM and mercury).

This equation can be applied for each type of electrical resource option and its associated MWh of expected production. These estimates of total emissions can then be summed across the electrical resource options to provide an estimate of the kilograms of conventional contaminants that will be produced for a given year at the power system level. Caution should always be applied that this final value represents an estimate and is not an absolute value of expected emissions.

Note that while it is acceptable to report these emissions as indicated above, a weighting scheme based on the potential for human health effects is presented in section 4.2.1 for consideration.

4.1.1.2 Greenhouse Gas Emissions

These criteria factors are reported in terms of the mass of CO_2 equivalents (T CO_2 eq.) per MWh and the final value recommended for comparison purposes should be represented as a summed total in T CO_2 eq./year. The application equation then becomes:

GHG Emissions (T CO_2eq./year) = (CO_2(T/MWh) + CH_4(T CO_2eq./MWh) + N_2O(T CO_2eq./MWh)) * Electricity production (MWh/year)

This equation should be applied for each resource option using its expected electrical production in the IPSP. These estimates of total emissions can then be added for each electrical resource to provide an estimate of the global warming potential for a given year and supply mix. Caution should always be applied that this final sum, either by electrical resource option or as a total for all options represents only an estimate and is not an absolute value of expected emissions.

4.1.2 Radioactivity

This criteria factor is reported in terms of person Sv/GWa and the final value recommended for comparison purposes should be represented as a summed total in person Sv. The application equation then becomes:

Radioactivity (person Sv) = Radioactivity (person Sv/GWa) * Electricity production (GWa)

This equation should be applied for each applicable electrical resource and its associated GWa of expected production in the IPSP. These estimates of total releases may then be summed across the electrical resource options to provide a total estimate, in person Sv, of radioactivity released for a given supply mix in that year. Caution should always be applied that this final value, either by electrical resource option or as a total for all options, represents only an estimate or is not an absolute value of expected releases.

4.1.3 Land Use

The factor value is reported in hectares per megawatt (ha/MW) and the final value recommended for comparison purposes should be represented as a summed total in hectares. The application equation for each resource then becomes:

Land Use (ha) = Land Use (ha/MW) * Electrical capacity (MW) + Transmission Land Use (ha)

where the Land Use in hectares on the right hand side of the equation is the land use associated with transmission resources. This equation should be applied for each type of electrical resource option and its associated capacity in MW (if applicable). The estimates of total land area under use may then be summed for all of the electrical resources, both generation and transmission, to yield a total estimate land used by a given supply mix. Caution should be exercised that the summed total represents only an estimate of the land that will be used and should not be represented as an exact value.

4.1.4 Water Use

The criteria factors for water flow through and consumption are reported in m^3/MWh and the final value recommended for comparison purposes should be represented as a summed total in m^3/year for both flow though and consumption. The application equations then become:

Flow through Water Use (m^3/year) = Flow through Water Use (m^3/MWh) * Electricity production (MWh/year)

Consumption Water Use (m^3/year) = Consumption Water Use (m^3/MWh) * Electricity production (MWh/year)

These equations should be applied for each type of electrical resource and its associated MWh/year of expected production. These estimates of total water use may then be summed across the electrical resource options to provide an estimate of both flow through and consumption water use in cubic meters for a given supply mix in a given year. Caution should be exercised that the final summed total for water use is represented only as an estimate and not as an absolute number.

4.1.5 Solid Wastes

The criteria factor for wastes is reported in T/MWh and the final value recommended for comparison purposes should be represented as a summed total in T/year. The application equation then becomes:

Waste (T/year) = Waste (T/MWh) * Electricity production (MWh/year)

This equation should be applied for each type of electrical resource option and its associated MWh/year of expected production. These estimates of total waste may then be summed across the electrical resource options to provide a total estimate of waste in tonnes for a given supply mix in a given year. Caution should be exercised that the final summed total for waste is represented as an estimate and not as an absolute value of waste that will be generated.

4.1.6 Supply Mix Comparisons

Once the criteria factors have been applied to the current mix or the IPSP, the environmental performance can be compared in one of two ways:

Comparing by resource option – different types of generation (e.g., natural gas) may be compared between supply mixes. Differences reflected for example by changes in station locations or emissions controls for a specific facility (or group of facilities) can be compared by the summed totals for each generation type or the supply mix as a whole. For example, a comparison could be made of the summed tonnes of CO_2 equivalents for natural gas in the current supply mix versus natural gas at the full implementation of the IPSP.

Comparing by environmental criteria – different electrical resource mixes (e.g., the current mix versus the IPSP at full implementation) can be compared by summed totals for each natural environment criteria. For example, a comparison could be made of the summed tonnes of CO_2 equivalents for all electrical resource options in the current electrical supply mix versus that after full IPSP implementation.

It is noted that comparison of future supply mixes that include different styles of facilities or new forms of electrical generation from those assumed in this report are likely to require additional data and potentially additional research before an analysis can be completed.

4.2 CRITERIA WEIGHTING

The relative importance of one aspect of the natural environment versus another is largely a measure of societal values and/or politics. However, further consideration can be made for conventional air emissions.

4.2.1 Conventional Contaminant Air Weighting

For conventional air contaminant emissions, weighting factors were developed based on environmental protection standards and used to normalize for the relative differences in the contaminants with respect to potential human health effects. The primary human health related pollutants considered are nitrogen oxides (NO_X), sulphur dioxide (SO_2), fine particles ($PM_{2.5}$)[2] and mercury. Contaminant weighting factors are presented in Table 4.1. Weighting of the individual contaminants allows for the creation of an index of overall emission value that sums across the individual contaminants. Note that the 2005 SENES report developed weighting factors for formaldehyde and benzene which are also presented in Table 4.1 for future reference purposes.

TABLE 4.1
CONVENTIONAL CONTAMINANT AIR EMISSION WEIGHTINGS
BASED ON HUMAN HEALTH EFFECTS

Contaminant	Value	Weighting Factor
NO_x[a]	100 µg/m^3	1
SO_2[b]	55 µg/m^3	100/55 = 1.8
$PM_{2.5}$[c]	15 µg/m^3	100/15 = 6.7
Mercury[d]	inhalation reference concentration is 0.3 µg/m^3	100/0.3 = 333
Benzene[e]	1x10^{-5} risk level for inhalation is 1.3 µg/m^3	100/1.3 = 77
Formaldehyde[f]	1x10^{-5} risk level for inhalation is 0.8 µg/m^3	100/0.8 = 125

[a]Environment Canada Maximum Acceptable Level (National Air Quality Objectives) (EC, 2003).
[b]Ontario MOE Annual Ambient Air Quality Criteria (ON MOE, 2001).
[c]U.S. EPA National Ambient Air Quality Standards (U.S. EPA, 2005a).
[d]U.S. EPA IRIS (U.S. EPA, 2005b).
[e]U.S. EPA IRIS (U.S. EPA, 2005b).
[f]U.S. EPA IRIS (U.S. EPA, 2005b).

[2] Note that this weighting is calculated based on $PM_{2.5}$ whereas the values presented in this report are both $PM_{2.5}$ and PM_{10}. Use of this weighting scheme would be a conservative representation of the potential human health effects for any PM_{10} values.

These weightings are meant to be applied to the factor values, with or without the air shed modifier, and then sum the contaminants for a total of conventional contaminant emissions making the equations in sections 4.1.1:

$$\text{Modified Conventional Emissions (kg/year)} = (1 * NO_x(\text{kg/MWh}) + 1.8 * SO_2(\text{kg/MWh}) + 6.7 * \text{PM(kg/MWh)} + 333 * \text{Mercury(kg/MWh)}) * \text{Electricity production (MWh/year)}$$

The weighted and modified emission totals can then be summed within the electrical resource option and then across all electrical resource options. Note that the use of the air shed modifier is not required to calculate the recommended index of conventional emissions. To calculate the index without the addition of this modifier, the ASm multiplier is removed from the above equation. Caution must be exercised in reporting this number as being representative of total emissions.

The weighting scheme presented in Table 4.1 represents just one potential scheme. Other weighting schemes can be developed but should be based on either stakeholder evaluations and public consultation or expert developed such as the two that were presented in the 2005 SENES report. These latter schemes were developed as part of the European Union ExternE project and were based on aggregated costs based on the relative damage to human health and the environment from the life-cycle effects of different power options (Dorland *et al.*, 1997 and Spadaro and Rabl, 1998). Because these schemes are based on life-cycle effects, they are not appropriate for the current analysis. However, something similar could be developed and applied to the criteria developed in this report.

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APPENDIX A

INPUT DATA FOR FACTOR DEVELOPMENT

TABLE A.1
RAW DATA FOR CONVENTIONAL CONTAMINANT EMISSIONS FACTOR CALCULATION

Fuel	Generation Style	Generation Station or Factor Source	Conventional Contaminant Emissions (kg)[1]						Assumed Heat Rate (btu/kWh) or 2005 Production (MWh)[3]	Conventional Contaminant Emission Factors (kg/MWh)					
			NO_X	SO_2	PM^2	Mercury	Formaldehyde	Benzene		NO_X	SO_2	PM	Mercury	Formaldehyde	Benzene
Natural Gas/Oil	Duel Fuel	Lennox Generating Station	1672812	2503354	1347				1351496 MWh	1.24	1.85	0.00100	No Data	No Data	No Data
Natural Gas	CHP (Electrical Output)	U.S. EPA (2000)	0.0990 lb/MMBtu	0.00340 lb/MMBtu	0.00660 lb/MMBtu		0.000710 lb/MMBtu	0.00000206 lb/MMBtu	6800 btu/kWh	0.305	0.0105	0.0204	Negligible	0.00219	0.00000635
Natural Gas	CHP (Total Energy Output)	U.S. EPA (2000)	0.0990 lb/MMBtu	0.00340 lb/MMBtu	0.00660 lb/MMBtu		0.000710 lb/MMBtu	0.00000206 lb/MMBtu	4800 btu/kWh	0.216	0.00740	0.0144	Negligible	0.00155	0.00000448
Natural Gas	Cogen	Cardinal Power	573799		31570		3396		1282051 MWh	0.448	No Data	0.0246	No Data	0.00265	No Data
Natural Gas	Cogen	Mississauga Cogeneration Plant	544142		11151				860822 MWh	0.632	No Data	0.0130	No Data	No Data	No Data
Natural Gas	Cogen	Fort Frances Division	753379	51943	122950				567809 MWh	1.33	0.0915	0.217	No Data	No Data	No Data
Natural Gas	Cogen	Iriquois Falls Generating Station	195284		7107				697218 MWh	0.280	No Data	0.0102	No Data	No Data	No Data
Natural Gas	Cogen	Lake Superior Power	374914		8989				345639 MWh	1.08	No Data	0.0260	No Data	No Data	No Data
Natural Gas	Cogen	NPIF Kingston CoGen Inc.	99403						481114 MWh	0.207	No Data	No Data	No Data	No Data	No Data
Natural Gas	Cogen	Ottawa Health Sciences Center Cogeneration Plant	309289		6941				405110 MWh	0.763	No Data	0.0171	No Data	No Data	No Data
Natural Gas	Cogen	Sarnia Regional Cogeneration Plant	1308055		74178				1610819 MWh	0.812	No Data	0.0460	No Data	No Data	No Data
Natural Gas	Cogen	West Windsor Power	207420		21740				797651 MWh	0.260	No Data	0.0273	No Data	No Data	No Data
Natural Gas	Cogen	Whitby Cogeneration	147000		2760				329780 MWh	0.446	No Data	0.00837	No Data	No Data	No Data
Natural Gas	Cogen	Windsor Essex Cogeneration Plant	124582		4783				309640 MWh	0.402	No Data	0.0154	No Data	No Data	No Data
Natural Gas	Average of Cogen less than 10 years old									0.436	0.0915	0.0215	No Data	No Data	No Data
Natural Gas	Average of Cogen									0.622	0.0915	0.0405	No Data	0.00265	No Data
Natural Gas	enhanced Combined Cycle	Kapuskasing Generating Station	79000		1500				260197 MWh	0.304	No Data	0.00576	No Data	No Data	No Data
Natural Gas	enhanced Combined Cycle	Nipigon Power Plant	250000		1500				288849 MWh	0.866	No Data	0.00519	No Data	No Data	No Data
Natural Gas	enhanced Combined Cycle	North Bay Power Plant	77000		1400				250317 MWh	0.308	No Data	0.00559	No Data	No Data	No Data
Natural Gas	enhanced Combined Cycle	Tunis Power Plant	350054		2004				330539 MWh	1.06	No Data	0.00606	No Data	No Data	No Data
Natural Gas	Average of enhanced Combined Cycle									0.634	No Data	0.00565	No Data	No Data	No Data
Natural Gas	Average of Cogen and enhanced Combined Cycle									0.606	0.0915	0.0305	No Data	0.00265	No Data
Natural Gas	CCGT	U.S. EPA (2000)	0.0990 lb/MMBtu	0.00340 lb/MMBtu	0.00660 lb/MMBtu		0.000710 lb/MMBtu	0.00000206 lb/MMBtu	6100 btu/kWh	0.274	0.00940	0.0183	Negligible	0.00196	0.00000570
Natural Gas	Combined-Cycle	Brighton Beach Power	203530		8849				1396995 MWh	0.146	No Data	0.00633	No Data	No Data	No Data
Natural Gas	SCGT	U.S. EPA (2000)	0.0990 lb/MMBtu	0.00340 lb/MMBtu	0.00660 lb/MMBtu		0.000710 lb/MMBtu	0.00000206 lb/MMBtu	8800 btu/kWh	0.395	0.0136	0.0263	Negligible	0.00283	0.00000822

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TABLE A.1 (Cont'd)
RAW DATA FOR CONVENTIONAL CONTAMINANT EMISSIONS FACTOR CALCULATION

Fuel	Generation Style	Generation Station	Conventional Contaminant Emissions (lb/MMBtu or kg)[1]						Assumed Heat Rate (btu/kWh) or 2005 Production (MWh)[3]	Conventional Contaminant Emission Factors (kg/MWh)					
			NO_X	SO_2	PM[2]	Mercury	Formaldehyde	Benzene		NO_X	SO_2	PM	Mercury	Formaldehyde	Benzene
Coal		Nanticoke Generating Station	23171155	67946900	665588	160.393			17851406 MWh	1.30	3.81	0.0373	0.00000898	No Data	No Data
Coal		Lambton Generating Station	8990586	29343100	756959	67.438			9496425 MWh	0.947	3.09	0.0797	0.00000710	No Data	No Data
Coal		Thunder Bay Generating Station	2742287	4214500	144823	37.18			991847 MWh	2.76	4.25	0.146	0.0000375	No Data	No Data
Coal		Atikokan Generating Station	1734763	4774300	11540	39.691			967983 MWh	1.79	4.93	0.0119	0.0000410	No Data	No Data
Coal	Average of Nanticoke, Lambton, Thunder Bay and Atikokan									1.70	4.02	0.0687	0.0000236	No Data	No Data
Pulverized Coal, Low NO_X with Post Burner Control, SO_2 Control[4]		U.S. EPA (1998)	0.663 lb/MMBtu	1.58 lb/MMBtu	0.214 lb/MMBtu	0.00000355 lb/MMBtu	0.0000556 lb/MMBtu	0.0000103 lb/MMBtu	3412 btu/kWh 35% Efficiency	0.403	1.54	0.0209	0.0000157	0.000246	0.0000454
Pulverized Coal, Low NO_X, No SO_2 control[4]		U.S. EPA (1998)	0.663 lb/MMBtu	1.58 lb/MMBtu	0.214 lb/MMBtu	0.00000355 lb/MMBtu	0.0000556 lb/MMBtu	0.0000103 lb/MMBtu	3412 btu/kWh 35% Efficiency	1.61	6.99	0.0209	0.0000157	0.000246	0.0000454
Coal	IGCC[5]									0.363	0.318	0.0635	0.0000204	No Data	No Data
Biomass - Wood		Calstock Power Plant	307440	25401	35553				175366 MWh	1.75	0.145	0.203	No Data	No Data	No Data
Biomass - Wood		Cochrane Generating Station	229390		10524				235741 MWh	0.973	No Data	0.0446	No Data	No Data	No Data
Biomass - Wood		Kirkland Lake Generating Station	1040500		32632				503346 MWh	2.07	No Data	0.0648	No Data	No Data	No Data
Biomass - Wood		Average Calstock, Cochrane and Kirkland Lake								1.60	0.145	0.104	No Data	No Data	No Data
Biomass - Dry Wood		U.S. EPA (2003)	0.490 lb/MMBtu	0.0250 lb/MMBtu	0.120 lb/MMBtu	0.00000350 lb/MMBtu	0.00440 lb/MMBtu	0.00420 lb/MMBtu	10000 btu/kWh	2.22	0.113	0.544	0.0000159	0.0200	0.0191
	CHP	U.S. EPA (2003)	0.490 lb/MMBtu	0.0250 lb/MMBtu	0.120 lb/MMBtu	0.00000350 lb/MMBtu	0.00440 lb/MMBtu	0.00420 lb/MMBtu	8000 btu/kWh	1.78	0.0907	0.435	0.0000127	0.0160	0.0152
Biomass - Wet Wood		U.S. EPA (2003)	0.220 lb/MMBtu	0.0250 lb/MMBtu	0.160 lb/MMBtu	0.00000350 lb/MMBtu	0.00440 lb/MMBtu	0.00420 lb/MMBtu	10000 btu/kWh	0.998	0.113	0.726	0.0000159	0.0200	0.0191
	CHP	U.S. EPA (2003)	0.220 lb/MMBtu	0.0250 lb/MMBtu	0.160 lb/MMBtu	0.00000350 lb/MMBtu	0.00440 lb/MMBtu	0.00420 lb/MMBtu	8000 btu/kWh	0.798	0.0907	0.581	0.0000127	0.0160	0.0152
Biogas - Landfill		U.S. EPA (2000)	0.14 lb/MMBtu	0.045 lb/MMBtu	0.023 lb/MMBtu			0.000021 lb/MMBtu	10000 btu/kWh	0.635	0.204	0.104	0.000	0.000	0.0000953
Biogas - Digester		U.S. EPA (2000)	0.16 lb/MMBtu	0.0065 lb/MMBtu	0.012 lb/MMBtu		0.00019 lb/MMBtu		10000 btu/kWh	0.726	0.0295	0.0544	0.000	0.000862	0.000
Nuclear - Uranium		Bruce Power	158630	653405	26650				33147232 MWh	0.00479	0.0197	0.000804	No Data	No Data	No Data
Nuclear – Uranium		Pickering Nuclear		1100		0.044			18079351 MWh	No Data	0.0000608	No Data	0.00000000243	No Data	No Data
Nuclear – Uranium		Darlington Nuclear	32186	1090	263	0.044			27722050 MWh	0.00116	0.0000393	0.00000949	0.00000000159	No Data	No Data
Nuclear – Uranium	Average of Nuclear Stations									0.00297	0.00660	0.000407	0.00000000201	No Data	No Data
Nuclear - Uranium	Pickering Nuclear[6]									0.00130	0.000688	0.0000680	0.000000000793	0.000000722	0.0000000557

[1]Data from U.S. EPA (1998, 2000 and 2003) represents emission rates in lb/MMBtu all other data is in kg of emissions

[2]Data from U.S. EPA (2000) as well as the value for IGCC represents PM_{10} emissions that are used as a conservative proxy for PM.

[3]Heat rate data is used for calculations using U.S. EPA (2000) emission rates; an efficiency is assumed for coal calculated using U.S. EPA (1998) emission rates; remaining data is annual production.

[4]Ontario coal stations all operate with low NO_X control and a few units have additional post burner (SCR) control. However, only some have SO_2 scrubber technology.

[5]from Ratafia-Brown *et al.* (2002)

[6]from Golder (2006)

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TABLE A.2
CONVENTIONAL CONTAMINANT CRITERIA FACTORS: U.S. EPA DERIVED* VERSUS NPRI DERIVED+

Generation Style and/or Fuel	NO_X (kg/MWh)	SO_2 (kg/MWh)	PM (kg/MWh)	Mercury (kg/MWh)
Natural Gas CHP -Electrical Output (Total Energy Output)*	0.305 (0.216)	0.0105 (0.00740)	0.0204 (0.0144)	No Emission Rate
Natural Gas CHP ON Stations Average of all 11+	0.622 (0.207-1.33)	0.0915[1]	0.0405 (0.00840-0.046)	No Data
Natural Gas CHP ON Stations Average of those built in last 10 years[2]+	0.436 (0.207-0.812	0.0915[1]	0.0215[3] (0.0102-0.0460)	No Data
Natural Gas CCGT*	0.274	0.00941	0.0183	No Emission Rate
Brighton Beach+	0.146	No Data	0.00633	No Data
Coal Average of ON Stations+	1.70 (0.947-2.76)	4.02 (3.09-4.93)	0.0687 (0.0119-0.146)	0.0000236 (0.00000710-0.0000410)
Pulverized Coal, Low NO_X with Post Burner Control, SO_2 Control*	0.403	1.54	0.0209	0.0000157
Pulverized Coal, Low NO_X, No SO_2 control*	1.61	6.99	0.0209	0.0000157
Biomass Average of ON Stations+	1.60 (0.973-2.07)	0.145[4]	0.104 (0.0446-0.203)	No Data
Biomass Dry Wood*	2.22	0.113	0.544	0.0000159
Biomass Dry Wood CHP*	1.78	0.0907	0.435	0.0000127
Biomass Wet Wood*	0.998	0.113	0.726	0.0000159
Biomass Wet Wood CHP*	0.798	0.0907	0.581	0.0000127
Biogas – Landfill*	0.635	0.204	0.104	No Data
Biogas – Digester*	0.726	0.0295	0.0544	No Data
Nuclear Average of ON Stations+	0.00297[5] (0.00116-0.00479)	0.00660 (0.0000393-0.0197)	0.000407[5] (0.00000949-0.000804)	0.00000000201[6] (0.00000000159-0.00000000243)
Nuclear Pickering estimated as U.S. EPA emission rates*	0.00130	0.000688	0.0000680	0.000000000793

Values in brackets provide the criteria factor range. Shaded rows represent the data used in the report.

[1]Only one station (Fort Frances Division) reported an emission value for SO_2 in NPRI (2007). The criteria factor values estimated for SO_2 are much less than the value reported by the Fort Frances Division station. This is likely because SO_2 emissions from natural gas stations are generally low and fall below the reporting threshold for *Canadian Environmental Protection Act* (20 T/year). It is unclear why the Fort Frances Division station is the only CHP station in Ontario with emissions greater than the reporting threshold.

[2]The four stations brought into service in the last ten years are Sarnia Regional Cogeneration Plant, Iroquois Falls Generating Station, Kingston CoGeneration Plant and Whitby Cogeneration Plant

[3]Average and range do not include Kingston CoGen which did not report a value to NPRI (2007) in 2005

[4]Value is for Calstock Power Plant

[5]Value is average of Bruce and Darlington.

[6]Value is average of Darlington and Pickering.

*Value is U.E. EPA derived. +Value is NPRI derived.

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TABLE A.3
RAW DATA FOR GREENHOUSE GAS EMISSIONS FACTOR CALCULATION

Fuel	Generation Style	Generation Station	GHG Emissions (Tonnes)[1]			Assumed Heat Rate (btu/kWh) or 2005 Production (MWh)[2]	GHG Emission Factors (T/MWh)		
			CO_2	CH_4 (CO_2 eq)	N_2O (CO_2 eq)		CO_2	CH_4 (CO_2 eq)	N_2O (CO_2 eq)
Natural Gas/Oil	Duel Fuel	Lennox Generating Station	983613	273	2790	1351496 MWh	0.728	0.000202	0.00206
Natural Gas	CHP (Electrical Output)	U.S. EPA (2000)	110 lb/MMBtu	0.00860 lb/MMBtu	0.00300 lb/MMBtu	6800 btu/kWh	0.339	0.000557	0.00287
Natural Gas	CHP (Total Energy Output)	U.S. EPA (2000)	110 lb/MMBtu	0.00860 lb/MMBtu	0.00300 lb/MMBtu	4800 btu/kWh	0.240	0.000393	0.00202
Natural Gas	Cogen	Cardinal Power	502037	864	4449	1282051 MWh	0.392	0.000674	0.00329
Natural Gas	Cogen	Mississauga Cogeneration Plant	439644	626	3192	860822 MWh	0.511	0.000727	0.00236
Natural Gas	Cogen	Fort Frances Division	277809	147	2083	567809 MWh	0.489	0.000260	0.00367
Natural Gas	Cogen	Iriquois Falls Generating Station	339692	464	2387	697218 MWh	0.487	0.000666	0.00342
Natural Gas	Cogen	Lake Superior Power	149812	246	1267	345639 MWh	0.433	0.000712	0.00366
Natural Gas	Cogen	NPIF Kingston CoGen Inc.	233325	0.340	1.80	481114 MWh	0.485	0.000000707	0.00000374
Natural Gas	Cogen	Ottawa Health Sciences Center Cogeneration Plant	246034	332	1683	405110 MWh	0.607	0.000818	0.00415
Natural Gas	Cogen	Sarnia Regional Cogeneration Plant	1259112	2142	10247	1610819 MWh	0.782	0.00133	0.00636
Natural Gas	Cogen	West Windsor Power	361432	572	2948	797651 MWh	0.453	0.000717	0.00370
Natural Gas	Cogen	Whitby Cogeneration	180601	263	1352	329780 MWh	0.548	0.000796	0.00410
Natural Gas	Cogen	Windsor Essex Cogeneration Plant	191161	274	1397	309640 MWh	0.617	0.000885	0.00451
Natural Gas	Average of Cogen less than 10 years						0.575	0.000698	0.00347
Natural Gas	Average of Cogen						0.528	0.000690	0.00357
Natural Gas	Average of Cogen and enhanced Combined Cycle						0.514	0.000681	0.00352
Natural Gas	enhanced Combined Cycle	Tunis Power Plant	120002	193	992	330539 MWh	0.363	0.000584	0.00300
Natural Gas	Average of enhanced Combined Cycle						0.363	0.000584	0.00300
Natural Gas	CCGT	U.S. EPA (2000)	110 lb/MMBtu	0.00860 lb/MMBtu	0.00300 lb/MMBtu	6100 btu/kWh	0.304	0.000500	0.00257
Natural Gas	Combined-Cycle	Brighton Beach Power	510000	840	63240	1396995 MWh	0.365	0.000601	0.0453
Natural Gas	SCGT	U.S. EPA (2000)	110 lb/MMBtu	0.00860 lb/MMBtu	0.00300 lb/MMBtu	8800 btu/kWh	0.439	0.000721	0.00371
Coal		Nanticoke Generating Station	17585856	3591	39990	17851406 MWh	0.985	0.000201	0.00224
Coal		Lambton Generating Station	8694815	1407	41850	9496425 MWh	0.916	0.000148	0.00441
Coal		Thunder Bay Generating Station	1150029	294	8680	991847 MWh	1.16	0.000296	0.00875
Coal		Atikokan Generating Station	1105064	273	3100	967983 MWh	1.14	0.000282	0.00320
Coal	Average of Nanticoke, Lambton, Thunder Bay and Atikokan						1.05	0.000232	0.00465
Pulverized Coal		U.S. EPA (1998)	195 lb/MMBtu	0.00184 lb/MMBtu	0.00257 lb/MMBtu	3412 btu/kWh 35% Efficiency	0.862	0.000171	0.00352
Coal	IGCC						0.798	No Data	No Data
Biomass - Wood Waste		Cochrane Generating Station	63473	111	3906	235741 MWh	0.269	0.000472	0.0166
Biomass - Wood Waste		Kirkland Lake Generating Station	186838	294	3689	503346 MWh	0.371	0.000584	0.00733
Biomass - Wood Waste		Average of Cochrane and Kirkland Lake					0.320	0.000528	0.0119
Biomass - Dry Wood		U.S. EPA (2003)	195 lb/MMBtu	0.0210 lb/MMBtu	0.0130 lb/MMBtu	10000 btu/kWh	0.885	0.00200	0.0183
	CHP	U.S. EPA (2003)	195 lb/MMBtu	0.0210 lb/MMBtu	0.0130 lb/MMBtu	8000 btu/kWh	0.708	0.00160	0.0146
Biomass - Wet Wood		U.S. EPA (2003)	195 lb/MMBtu	0.0210 lb/MMBtu	0.0130 lb/MMBtu	10000 btu/kWh	0.885	0.00200	0.0183
	CHP	U.S. EPA (2003)	195 lb/MMBtu	0.0210 lb/MMBtu	0.0130 lb/MMBtu	80000 btu/kWh	0.708	0.00160	0.0146
Biogas – Landfill gas		U.S. EPA (2000)	50 lb/MMBtu	No EF	No EF	10000 btu/kWh	0.227	No EF	No EF
Biogas - Digester		U.S. EPA (2000)	27 lb/MMBtu	No EF	No EF	10000 btu/kWh	0.122	No EF	No EF

[1]Data from U.S. EPA (1998, 2000 and 2003) represents emission rates in lb/MMBtu, all other data is in kg of emissions.

[2]Heat rate data is used for calculations using U.S. EPA (2000) emission rates; an efficiency is assumed for coal calculated using U.S. EPA (1998) emission rates; remaining data is annual energy production.

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TABLE A.4
GHG CRITERIA FACTORS:
U.S. EPA DERIVED* VERSUS NPRI DERIVED+

Generation Style and/or Fuel	CO_2 (T/MWh)	CH_4 (T CO_2 eq/MWh)	N_2O (T CO_2 eq/MWh)
Natural Gas CHP - Electrical Output (Total Energy Output)*	0.339[1] (0.240)	0.000557 (0.000393)	0.00287 (0.00202)
Natural Gas CHP ON Stations Average of all 11+	0.528 (0.392-0.782)	0.0000690 (0.000000707-0.00133)	0.00371 (0.00000374-0.00636)
Natural Gas CHP ON Stations Average of those built in last 10 years[2]+	0.575 (0.485-0.782)	0.000698 (0.000000707-0.00133)	0.00347 (0.00000374-0.00636)
Natural Gas CCGT*	0.304	0.000500	0.00257
Brighton Beach+	0.365	0.000601	0.0453
Coal Average of ON Stations+	1.05 (0.916-1.16)	0.00232 (0.000148-0.000296)	0.00465 (0.00224-0.00875)
Pulverized Coal*	0.862	0.000171	0.00352
Biomass Average of ON Stations+	0.320 (0.269-0.371)	0.000528 (0.000472-0.000584)	0.0119 (0.0073-0.0166)
Biomass Dry Wood*	0.885	0.00200	0.0183
Biomass Dry Wood CHP*	0.708	0.00160	0.0146
Biomass Wet Wood*	0.885	0.00200	0.0183
Biomass Wet Wood CHP*	0.708	0.00160	0.0146
Biogas – Landfill*	0.227	No Emission Rate	No Emission Rate
Biogas – Digester*	0.122	No Emission Rate	No Emission Rate

Shaded rows represent data used in the report.

[1]The criteria factor values for CO_2 estimated using U.S. EPA (2000) emission factors are lower than both the average and range estimated using station emissions reported in EC (2007). However, without further knowledge about how the total emissions for the EC (2007) database were calculated for each station, there is no obvious explanation for the difference.

[2]The four stations brought into service in the last ten years are Sarnia Regional Cogeneration Plant, Iroquois Falls Generating Station, Kingston CoGeneration Plant and Whitby Cogeneration Plant.

*Value is U.E. EPA derived. +Value is NPRI derived.

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TABLE A.5
RAW DATA FOR LAND USE FACTOR CALCULATION

Electricity Resource	Generation Style/Station	Fuel	Land (ha)	Land (acre)	Land (km^2)	MW	Land Use (km^2/MW or km^2)	Land Use (ha/MW)
Fossil	Lennox	Natural Gas/Oil			1.78	2140	0.000832	0.0832
	Average for all Natural Gas	Natural Gas					0.000139	0.0139
	Northland Power/Abitibi	Natural Gas			0.01	255	0.0000392	0.00392
	Brighton Beach	Natural Gas			0.1	580	0.000172	0.0172
	PEC	Natural Gas	11.3		0.113	550	0.000205	0.0205
	Average of ON Plants	Coal					0.00430	0.430
	Nanticoke	Coal			3.24	3938	0.000823	0.0823
	Lambton	Coal			3.35	1975	0.00170	0.170
	Thunder Bay	Coal			0.53	326	0.00163	0.163
	Atikokan	Coal			3	230	0.0130	1.30
	IGCC/Mesaba just project	Coal	68.8	170	0.688	1212	0.000568	0.0568
	Mesaba with buffer land		510	1260	5.10	1212	0.00421	0.421
Biomass	Average	Wood Waste					0.00909	0.909
	NGPP Minnesota		52.9		0.529	38.5	0.0137	1.37
	St. John		6.88	17	0.0688	15.5	0.00444	0.444
Nuclear	Average of ON Stations	Uranium					0.00166	0.166
	Pickering				2.1	3100	0.000677	0.0677
	Darlington				5	3524	0.00142	0.142
	Bruce				13.4	4640	0.00289	0.289

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TABLE A.5 (Cont'd)
RAW DATA FOR LAND USE FACTOR CALCULATION

Electricity Resource	Generation Style/Station		Fuel	Land (ha)	Land (acre)	Land (km^2)	MW	Land Use (km^2/MW or km^2)	Land Use (ha/MW)
Hydroelectric	Peaking		Water						20.3
	Baseload		Water						1.25
	Pumped Storage		Water					0.250	25.0
Wind	Average of ON Wind Sites		Wind					0.360	36.0
	Erie Shores			5260		52.6	99	0.531	53.1
	Kingsbridge I			1000		10	39.6	0.253	25.3
	Kingsbridge II			4000		40	159	0.252	25.2
	Kruger Energy Port Alma			4800		48	101	0.474	47.4
	Leader A&B			5600		56	200	0.280	28.0
	Melancthon I			2500		25	67.5	0.370	37.0
	Melancthon II			4860		48.6	132	0.368	36.8
	Prince I			2500		25	99	0.253	25.3
	Prince II			5200		52	90	0.578	57.8
	Ripley			3600		36	76	0.474	47.4
	Wolfe Island			2510		25.1	198	0.127	12.7
Photovoltaic			Solar						0
Fuel Cells			Hydrogen						Negligible
Other Transmission			N/A						9515 ha
Hydroelectric Import	Manitoba	Hydro	Water			5	1250	0.00400	0.400
		Transmission	N/A			56		5600	5600 ha
	Quebec	Hydro	Water			9900	10300	0.961	96.1
		Transmission	N/A			0		0.000	0 ha
Total Transmission			N/A						15115 ha

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TABLE A.6
HYDROELECTRIC PEAKING LAND USE RAW DATA

River	Generating Station	Capacity (MW)	Reservoir Area (ha)	ha/MW
Mattagami	Harmon	141	251	1.78
Mattagami	Kipling	149	141	0.946
Mattagami	Little Long	133	7,167	53.9
Mattagami	Smoky Falls	52	213	4.10
Mississagi	Red Rock Falls	38	625	16.4
Kaministiquia	Kakabeka Falls	25	126	5.04
Nipigon	Pine Portage	142	3,800	26.8
Madawaska	Arnprior	82	663	8.09
Madawaska	Mountain Chute	170	3,240	19.1
Ottawa	Otto Holden	243	3,600	14.8
Ottawa	Des Joachims	429	8,424	19.6
Ottawa	Chats Falls	96	7,020	73.1
Average				**20.3**

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TABLE A.7
HYDROELECTRIC BASELOAD LAND USE RAW DATA

River	Generating Station	Capacity (MW)	Estimated Facility and Headpond* Area (ha)	ha/MW
Mattagami	Lower Sturgeon	5	2.5	0.500
Mattagami	Sandy Falls	3	6	2.00
Mattagami	Wawaitin	11	10	0.909
Montreal	Hound Chute	4	2	0.500
South Muskoka	Hanna Chute	1	3	3.00
South Muskoka	South Falls	4	7	1.75
South Muskoka	Tretheway	2	3	1.50
Rideau	Merrickville	2	2	1.00
Trent	Frankford	3	3	1.00
Trent	Seymour	6	2	0.333
Trent	Sidney	4	5	1.25
Average				**1.25**

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TABLE A.8
TRANSMISSION OPTION LAND USE RAW DATA

TRANSMISSION OPTIONS	Est. New Line Length (km)	ROWs Req.	Est. ROW Area (ha)
New 500 kV transmission lines from approx. Moose River (south of Moosonee) to Hanmer TS (in Sudbury)	450	2	3,150
New 500 kV transmission lines from Hanmer TS (in Sudbury) to the GTA	400	2	2,800
New 500 kV transmission line from Bowmanville SS to Parkway TS (ROW exists already)	65	1	228
New 500 kV from Conawapa, Manitoba, to Hanmer TS (in Sudbury) (assume direct route)	1600	1	5,600
New 500 kV line from Hamner TS (Sudbury) to Mississagi TS (near Thessalon)	193	1	676
Redevelopment existing 230 kV line to new 500 kV line from Hamner TS (Sudbury) to Mississagi TS (near Thessalon)	193	0	0
New 230kV line from 3rd Line TS (in Sault Ste. Marie) to Mississagi TS (near Thessalon)	76	2	532
New 230kV line from MacKay TS (near Montreal River) to 3rd Line TS (in Sault Ste. Marie)	91	2	637
New 230 kV transmission line from Parkway TS (Hwy 407 and Warden Ave.) to Hearn TS (in Toronto Portlands)	25	1	88
Redevelop existing 115kV line from Richview TS to Manby TS to 230kV line	8	0	0
New 230 kV transmission line from Maidstone Junction (near town of Essex) to Lauzon TS (on east side of Windsor)	14	1	49
New 230kV transmission line from new Staples Junction to new Leamington TS	12	1	42
New 230 kV line from Alexander SS (near Nipigon) to Little Jackfish generation site (at north end of Lake Nipigon)	150	1	525
New 230 kV from Espanola to Manitowaning (possibly rebuild or upgrade existing 115 kV portion from Espanola to Little Current)	78	1	273
New 230 kV from Owen Sound TS to Tobermorey	109	1	382
Redevelop existing 115 kV to 230 kV from Seaforth TS to Goderich TS	34	0	0
New 230 kV transmission line from Milton TS to Hurontario SS (ROW already exists)	16	1	56
Upgrade 230 kV line from Hurontario Junction (near Hwys 401 and 10) and to Pleasant TS (in Brampton)	7	0	0
New 230 kV line from Lakehead TS (east of Thunder Bay) to Birch TS (in Thunder Bay)	22	1	77
Ontario-Quebec Purchase – assume use of existing 230 kV connection between Cumberland, in the City of Ottawa, and Masson, Quebec	10	0	0
Total			15,115

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TABLE A.9
RAW DATA FOR WATER USE FACTOR CALCULATION

Electricity Resource	Generation Style/Station	Fuel	Cooling Water System	Flow through	Consumption	MW	MWh	Water Use	
								Flow Through (m^3/MWh)	Consumption (m^3/MWh)
Fossil	Lennox	Natural Gas/Oil	Once-through					No Data	No Data
	Cogeneration	Natural Gas	ACC					0	Same as CHP once-through
			Cooling Tower					0	No Data
			Once-through	17033 L/s	66 L/s	588.5		104	0.404
	Combined Cycle	Natural Gas	ACC		18.35 m^3/hr	680		0	0.0270
			Cooling Tower					0	No Data
			Once-through		15.6 m^3/hr	680		Same as CHP once-through	0.0229
	Single Cycle	Natural Gas	ACC					0	Same as CCGT ACC
			Cooling Tower					0	No Data
			Once-through					Same as CHP once-through	Same as CCGT Once-through
	Average of ON Plants	Coal	Once-through	2423 m^3/min	3730000000 L/day		1975	73.6	5.08
	Nanticoke	Coal	Once-through					0	0
	Lambton	Coal	Once-through					0	0
	Thunder Bay	Coal	Once-through					0	0
	Atikokan	Coal	Once-through					0	0
	IGCC	Coal	Once-through		925 gallons/MWh			0	3.50
Biomass		Wood Waste						Same as Coal	Same as Coal
Nuclear	Pickering Nuclear	Uranium	Once-through	190 m^3/s			4120	166	0.332

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TABLE A.9 (Cont'd)
RAW DATA FOR WATER USE FACTOR CALCULATION

Electricity Resource	Generation Style/Station		Fuel	Cooling Water System	Flow through	Consumption	MW	MWh	Water Use	
Hydroelectric	Peaking Small (<20MW)		Water	N/A					50000	Negligible
	Peaking Medium (21-200MW)								20000	Negligible
	Peaking Large (>201MW)								12000	Negligible
	Baseload Small (<20MW)		Water	N/A					50000	Negligible
	Baseload Medium (21-200MW)								20000	Negligible
	Baseload Large (>201MW)								12000	Negligible
	Pumped Storage Small (<20MW)	Open	Water	N/A					50000	Negligible
		Closed							Negligible	Negligible
	Pumped Storage Medium (21-200MW)	Open							20000	Negligible
		Closed							Negligible	Negligible
	Pumped Storage Large (>201MW)	Open							12000	Negligible
		Closed							Negligible	Negligible
Wind			Wind	N/A					0	Negligible
Photovoltaic			Solar	N/A					0	0
Fuel Cells			Hydrogen						0	0
Transmission			N/A	N/A					0	0
Hydroelectric Import	Manitoba	Hydro	Water	N/A					12000	Negligible
		Transmission	N/A	N/A					0	0
	Quebec	Hydro	Water	N/A					12000	Negligible
		Transmission	N/A	N/A					0	0

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TABLE A.10
WATER USE OF HYDROELECTRIC GENERATING STATIONS

Station Capacity	Mean Annual Turbine Flow versus Net Energy Production (litres/MWh)
<10 MW	50,250,500
10-20MW	27,746,000
21-100 MW	17,539,500
101-200 MW	15,734,500
201-300 MW	11,909,000
> 300 MW	> 11,909, 000

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TABLE A.11
RAW DATA FOR WASTES FACTOR CALCULATION

Electricity Resource	Generation Style/Station		Fuel	Comments	Solid Wastes (T)	MWh	Solid Wastes Generated (T/MWh)
Fossil	Lennox		Natural Gas/Oil				Negligible
	CHP		Natural Gas				
	Combined Cycle		Natural Gas				
	Single Cycle		Natural Gas				
	Average of ON Plants		Coal		485067	30014479	0.0162
	IGCC		Coal	Number is lb/MWh	175		0.0794
Biomass			Wood Waste		5.8	532000	0.0000109
Nuclear	Ontario Stations		Uranium	Low and Intermediate-level stored waste	1958	42158000	0.0000753
				Used fuel stored in 2004	1216	42158000	
Hydroelectric	Peaking		Water				Negligible
	Baseload		Water				
	Pumped Storage		Water				
Wind			Wind				Negligible
Photovoltaic			Solar				0
Fuel Cells			Hydrogen				Negligible
Transmission			N/A				Negligible
Hydroelectric Import	Manitoba	Hydro	Water				Negligible
		Transmission	N/A				
	Quebec	Hydro	Water				
		Transmission	N/A				

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APPENDIX B

ENVIRONMENTAL CRITERIA MODIFIERS

APPENDIX B: ENVIRONMENTAL CRITERIA MODIFIERS

The modifiers outlined in the following sections provide the user with a method to incorporate aspects of environmental effects on the natural environment from electrical resource options that are less easily quantified. However, the application of modifiers is not necessary to use the preceding methodology (i.e., as presented in Chapters 1 through 4 of this document). Instead, modifiers are provided here as a means to help distinguish between supply mixes or generation options for which differences are not apparent using the criteria factors alone.

Modification of criteria factors may be done for an entire plan/supply mix or for generation types within a plan/supply mix. Modifiers are helpful in allowing potential effects from changes in the location of a generation type, either at the plant level or at the generation type level, to be elucidated. For example, if current wind production is focused in the Northeast IESO zone (2006) near parks or conservation reserves, but could be located in the Southwest IESO zone (2006) on brownfield land, the application of modifiers would showcase the difference in criteria factors that would otherwise not be shown without modification.

When comparing electrical supply mixes, it is important that modified totals only be compared with modified totals (or unmodified with unmodified). The modifiers are intended to capture effects on the natural environment that are not already included in the unmodified criteria factors such as the potential cumulative effects from emissions in an air shed with air quality that is already compromised. By modifying (essentially scaling) the estimated emissions or use, these additional effects become included in the criteria factor.

Caution must be made in reporting totals for comparison after they have been modified because, even though they have the same units as the unmodified criteria factors, they should not be taken to represent absolute values of expected emissions or use. That is, the modified criteria factor has units (mass per year, volume per year or area) but this is simply a means to compare options and should not be taken to represent the amount of emissions in those units (mass per year, volume per year or area). Once a criteria factor has been modified, it is not the absolute value that is being weighted, rather this value is used as a proxy for potential environmental effects.

B.1 AIR EMISSIONS MODIFIER

B.1.1 Air Shed

It is important to recognize and account for the potential for cumulative effects on air sheds from the addition of generation options to regions already under stress from an air quality perspective. This modifier is intended to highlight areas where cumulative effects are possible and where air emissions may be more likely to contribute to additional effects on local air quality. For the

purposes of this report, four categories of potential air shed quality have been selected for inclusion based on the categories used by the Ontario Ministry of the Environment in the Ontario Air Quality Forecast (ON MOE, 2007) and are presented in Table B.1 along with their associated multiplier values presented in Table B.1. The multiplier values are based on professional judgement.

TABLE B.1
AIR SHED CATEGORY DEFINITIONS AND MULTIPLIER VALUES

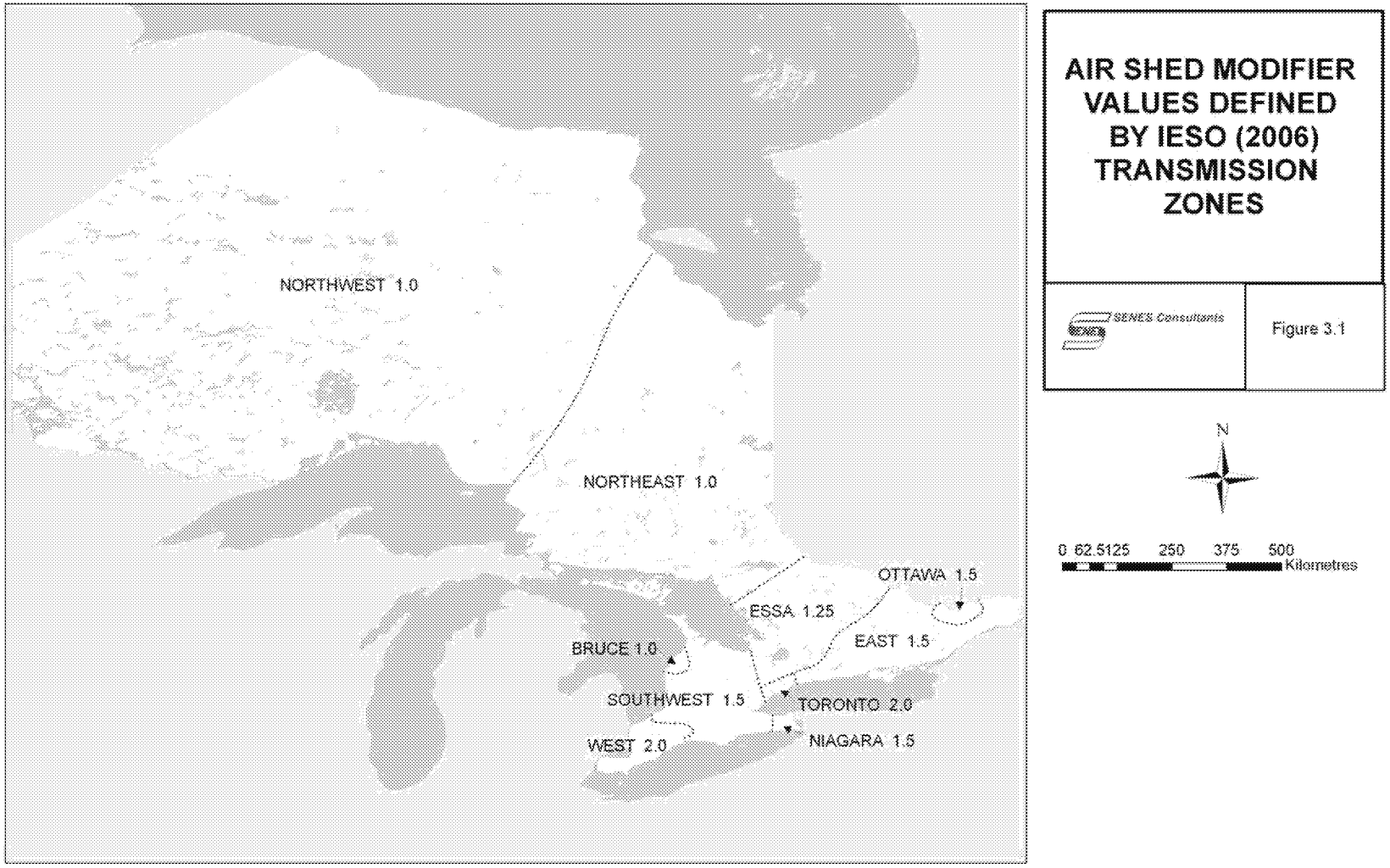
Definition	Multiplier Value
Air shed generally shows relatively good air quality.	1
Air shed generally shows moderate air quality.	1.25
Air shed generally shows poor air quality.	1.5
Air shed currently shows very poor air quality.	2.0

Using the categories defined in Table B.1 as a reference point, particulate matter emissions (NRC, 2004) and SENES in-house expert knowledge, the general air quality of each of the IESO transmission zones (IESO, 2006) has been categorized into the Table B.1 classifications, as presented in Table B.2. Figure B.1 provides a map of the IESO zones (2006) with the associated air shed modifier value from Table B.2. The application of the air shed modifier is intended to apply to all types of generation, but only to the conventional contaminant air emissions. No regional air shed modifier should be applied to greenhouse gas emission because their emissions are a global issue irrespective of where the emissions occur.

TABLE B.2
AIR SHED MODIFIER CATEGORIES AND MULTIPLIERS
DEFINED BY IESO (2006) TRANSMISSION ZONES

Zone	Definition	Multiplier
Northwest	Air shed generally shows relatively good air quality.	1
Northeast	Air shed generally shows relatively good air quality.	1
Bruce	Air shed generally shows relatively good air quality.	1
Essa	Air shed generally shows moderate air quality.	1.25
Southwest	Air shed generally shows poor air quality.	1.5
Niagara	Air shed generally shows poor air quality.	1.5
East	Air shed generally shows poor air quality.	1.5
Ottawa	Air shed generally shows poor air quality.	1.5
West	Air shed currently shows very poor air quality.	2.0
Toronto	Air shed currently shows very poor air quality.	2.0

FIGURE B.1
AIR SHED MODIFIER VALUES BY IESO TRANSMISSION ZONES



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B.1.2 Utilization of Air Shed Modifier

Because the air shed modifier is defined by using information developed for the IESO zones (2006), its application is fairly straightforward. For a given generating station (transmission options are assumed to have zero air emissions) located in a specific zone, the modifier can be applied to the conventional air emission criteria factors before calculating the total emissions for the resource. With the application of the air shed modifier, the equation from Section 4.1.1 becomes:

Modified Conventional Emissions (kg/year) = (ASm * Emission rate (kg/MWh)) * Electricity prod (MWh/yr)

And the equation from Section 4.2.1 becomes:

Modified Conventional Emissions (kg/year) = (1 * ASm * NO_x(kg/MWh) + 1.8 * ASm * SO_2(kg/MWh)
+ 6.7 * ASm * PM(kg/MWh) + 333 * ASm * Mercury(kg/MWh)) * Electricity production (MWh/year)

where ASm is the appropriate multiplier from Table B.2 for each generating station.

The modified emission totals can then be summed within the generating options and then across all generating options for a total for the supply mix. Caution is expressed that these totals do not represent an absolute value and should not be represented as such.

B.2 LAND USE MODIFIERS

Two land use modifiers have been developed for this report.

B.2.1 Quality of Land Used or Lost

This modifier has been developed to account for the quality of the land that will be impacted or lost by the development of generation or transmission resources. It is recognized that the construction and operation of electrical generation and transmission facilities, wherever located, will cause some changes to the natural environment. However, all aspects of the environment are not altered in the same manner, in the same physical space, or over the same time frame. The nature and the significance of the change varies according to the type of facilities installed, the methods of construction followed, the mitigation measures applied, and ongoing operational activities undertaken as well as the quality of the land that will be impacted from a natural environment perspective.

This modifier acknowledges that certain components of the natural environment are generally viewed to be of greater value than others. To define the quality of land, four categories were

developed and assigned multiplier values to reflect the relative value of their environmental components; multiplier values are based on professional judgement. It is noted that the categories do not represent an exhaustive list of potential land uses that are important to the natural environment that could be impacted by generation options. Instead, they are intended to represent major land use categories that can be identified with respect to importance from a natural environment perspective. The four categories and associated multipliers are presented in Table B.3.

TABLE B.3
MODIFIER CATEGORIES AND MULTIPLIERS FOR LAND USE QUALITY

Category	Definition	Multiplier
1	• National and Provincial Parks and Conservation Authority areas. • Land previously inaccessible or rarely accessed by humans including lands that are not currently fragmented by roads or other linear features.	1.5
2	• Significant or sensitive biological areas such as Areas of Natural or Scientific Interest (ANSIs), Environmentally Sensitive Areas, Significant Ecological Areas, National Wildlife Areas, Conservation Reserves, Conservation Areas etc. • Water features such as lakes, streams or wetlands.	1.25
3	• Land that is currently developed, has been zoned for development or is an infill site.	1
4	• Brownfields and other sites that will benefit from development through clean-up requirements.	0.75

Categories 3 and 4 defined in Table B.3 are intended to consider lands that are not in a natural state, such as an infill or brownfield site, for which development may add value or represent an improvement to the natural environment. It is assumed that developing a brownfield site would positively impact the environment because it is likely to require some degree of remediation. Therefore, the impact implied by the analysis is less for brownfield sites than for other sites and consequently, the multiplier is less than one. This modifier assumes that an urban, suburban or industrial infill site[3] that is not contaminated nor is currently developed is the baseline condition and would receive a multiplier of one with respect to any new developments proposed in the IPSP. Categories 1 and 2 defined in Table B.3 represent lands that are important for their natural resource value and therefore these land classifications receive multipliers greater than one.

In setting the actual values for the land use quality multiplier, it was decided, based on professional judgement, that the quality of the land should not count for a positive or negative determinant in more than 25% increments. This is partially based on the site-specific nature of

[3] An infill site is defined as a parcel of land that, while not a brownfield, is also not undeveloped, natural habitat land. These sites may, or may not, have been previously developed but, are generally found within municipality limits and have undergone some form of modification from what would have been the natural condition.

land quality and because there is a large degree of human perception, or value judgments, with respect to quality. For example, a pristine stream in northeast Ontario may be perceived as having higher 'quality' than green space that traverses a suburban neighbourhood. In this situation, it is conceivable that modifier multipliers of 1.5 and 1.1, respectively, would be more appropriate. This kind of judgement, however, is beyond the scope of this report.

As a visual aid, a map illustrating most of the categories of land use defined in Table B.3 is provided as Figure B.2. Data for Figure B.2 is referenced from Land Information Ontario (LIO, 2005) and ESRI (2005). The line indicating "Limited Human Access" represents the line above which road access is currently limited. Lack of road access deters activities such as recreation and hunting and limits corridor and fragmentation effects on forest species. It is recognized that the scale of this map may not provide the user with enough information for site-specific reference. Further, not every feature listed in Table B.3 is reflected on the map in Figure B.2.

It must be noted that the application of this modifier requires site specific information and is likely to require detailed location and project specific knowledge. For any given generation option, it is not possible to say that only one land classification is applicable in all cases. For example, it is not possible to assume that wind farms will only be developed on agricultural land and not on brownfield sites. While this modifier is important at a site specific level, it can not be applied broadly, and therefore, its application becomes more complicated. When assessing the category that a given electricity resource option would fall into, the multiplier that should be applied is the highest value that is applicable. For example, if a generation option is located on land that has been zoned for development but will result in the loss of a wetland, the multiplier 1.25 should be applied rather than 1.0.

B.2.2 Availability for Alternative Use

This modifier is intended to account for the potential for generation and transmission sites to be accommodating of other land uses. Some generation and transmission facilities can coexist with other land use activities. For example, although a relatively large area is required for a wind farm, land between the turbines still supports use by biota and reservoirs created by hydroelectric stations provide lacustrine aquatic habitats. More difficult to define are transmission lines sited through forested areas. These lines allow for passive wildlife use between the tower footings, but the vegetation is controlled, and the corridors fragment the forest resulting in new human access and competition from edge-species like cowbirds and crows.

FIGURE B.2
ONTARIO LAND USE OF SIGNIFICANCE TO THE NATURAL ENVIRONMENT



ONTARIO LAND USE OF SIGNIFICANCE TO THE NATURAL ENVIRONMENT

SENES Consultants | Figure 3.2

N

0 62.5 125 250 375 500 Kilometres

- ANSI
- Significant Ecological Area
- Environmentally Sensitive Area
- National Wildlife Area
- Conservation Reserve Regulated
- Conservation Area
- Provincial Park
- Limited Human Access

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Table B.4 summarizes the three categories defined for this modifier and the associated modifier values which have been defined based on professional judgement.

TABLE B.4
MODIFIER CATEGORIES AND MULTIPLIERS FOR AVAILABILITY FOR ALTERNATIVE USE

Category	Definition	Multiplier
1	• Neighbouring land use is restricted due to generating station or transmission line presence	1.25
2	• No alternate use available	1.0
3	• Available for wildlife use such as grazing or migrating • Available for human use such as agriculture	0.75

This modifier estimates the amount of land that would still be available for some form of use by the natural environment. In developing the numeric value for the multiplier, it was important that the range represent a logical estimate of the land that may remain available for other uses following the development. As such, questions such as "When a wind farm is developed, how much of the land is still available, and with sufficient quality, for biological use?" were asked. Similar questions can be asked for hydroelectric reservoirs and buffer zones around thermal or nuclear generating stations. The answer to these questions varies not only on a site specific basis but also by generation option. It was determined that broad generalizations regarding the amount of land that could have secondary usage by biological organisms (as habitat or even feeding sites) could be made. Table B.5 provides the suggested modifier values for resource options identified in this report based on professional judgement. Caution is warranted in using this modifier as to not over-estimate the amount of land that may remain available because these areas, while available for use, may not represent land quality that is equivalent to pre-development. As such, it has been determined that a 25% benefit could be applied to a site if it remains available for biological use following the development.

TABLE B.5
AVAILABILITY FOR ALTERNATIVE USE
MODIFIER AND MULTIPLIER VALUES

Electrical Resource		Category	Reasoning	Multiplier Value
Natural Gas		2	Generally sites are either conjoined to other industrial sites or do not include any buffer land nor do they restrict surrounding land.	1.0
Coal		2	Generally sites do not include any buffer land nor do they restrict surrounding land.	1.0
Biomass		2	Generally sites are either conjoined to other industrial sites or do not include any buffer land nor do they restrict surrounding land.	1.0
Nuclear		3	Generally sites include buffer land and while they restrict land use from a human perception, it is generally not restricted from a natural environment perspective.	0.75
Hydroelectric		3	Generally site provides additional habitat, albeit of a different value, than was previously available and from a natural environment perspective, surrounding land is available for use.	0.75
Hydroelectric Import	Manitoba	1	Generally, the land use in Ontario is transmission in the northwest portion of the province where fragmentation will be an issue and forest species (both flora and fauna) use will be restricted	1.25
	Quebec	3	Generally, the land use in Ontario is for transmission in the southeast portion of the province where the land use will not be restricted from a natural environment perspective.	0.75
Wind		3	Generally, sites are nearly as available from a natural environment perspective after development as they were before and surrounding land use is not restricted.	0.75

TABLE B.5 (Cont'd)
AVAILABILITY FOR ALTERNATIVE USE
MODIFIER AND MULTIPLIER VALUES

Electrical Resource		Category	Reasoning	Multiplier Value
Photovoltaic		N/A	It is assumed that no land is used for photovoltaic generation development	N/A
Transmission	Northern quarter of Ontario	1	Generally, land above the Limited Human Access line in Figure 3.2 is area where fragmentation will be an issue and forest species (both flora and fauna) use will be restricted.	1.25
	Remainder of Ontario	3	Generally, the land use in Ontario is such that transmission will not restrict natural environment use.	0.75

B.2.3 Utilization of Land Use Modifiers

B.2.3.1 Quality of Land Used or Lost

The modifier for quality of land impacted or lost requires user knowledge for its application because assumptions can not be made across either IESO defined zones or across electrical resource options. Instead, an evaluation must be made at the siting level of the quality of the land that will be impacted. To a large degree, the subjectivity involved in such an evaluation has been removed by defining the modifier categories such that only if the actual footprint of the electrical resource option affects the defined land use is the application of this modifier warranted. However, application still involves user interaction and knowledge pertaining to option siting. As such, without site-specific information, it should be assumed that siting will be on category 3 land for which the multiplier value is one. It is entirely possible that siting of most options will be on such land as a matter of general practice.

Should it be determined that this modifier will be applied, the equation in section 4.1.3 becomes:

Land Use (ha) = QLm * (Land Use (ha/MW) * Electrical Capacity (MW) + Transmission Land Use (ha))

where QLm is the appropriate multiplier from Table B.3 for each generating station or transmission line.

The modified land use factor may then be summed across the stations and lines of each electrical resource option, then across all electrical resource options for a supply mix total. Caution is again made that these land use values should not be expressed as absolute values.

B.2.3.2 Availability for Alternative Use

Assumptions were made for the application of this modifier such that the same multiplier is applied across electrical resource options, with the exception of transmission where determination must first be made regarding whether the transmission option will be located in the northern quarter of Ontario (above the limited human access line delineated in Figure B.2) or below this line. The equation in section 4.1.3 becomes:

Land Use (ha) = AUm * (Land Use (ha/MW) * Electrical capacity (MW) + Transmission Land Use (ha))

where AUm is the appropriate multiplier from Table B.5 for each electrical resource option.

The modified emission totals may then be summed within and across the electrical resource options. Caution must be exercised that these land use values should not be represented as absolute values.

B.2.3.3 Application of Both Land Use Modifiers

Application of both land use modifiers would result in the equation from section 4.1.3 becoming:

Land Use (ha) = QLm * AUm * (Land Use (ha/MW) * Electrical capacity (MW) + Transmission Land Use (h))

where both QLm, the land quality multiplier from Table B.3, and AUm, the land availability multiplier from Table B.5, are applied at the level of the individual generation station (e.g. biomass station located on infill site) or transmission line.

The modified values are then summed to create a total for each electrical resource option (e.g. all biomass stations) then across all generation and transmission options for a land use total in modified hectares. This modified value must not be represented as an absolute value.

B.3 WATER USE MODIFIERS

SENES (2005) contains two water use modifiers: one that accounted for the presence of fish and one that accounted for chemical or physical changes to water quality. It should be noted that only the former was applied in the 2005 report. This report retains both modifiers in refined form.

B.3.1 Presence of Aquatic Biota

In estimating water impacts, BC Hydro (2005) utilized the presence of fish as a modifier. In their report, they assumed that a water body with no fish was at low risk from impacts from hydro development and, therefore, water impacts could be set to zero by applying a multiplier of zero. Water bodies with fish were simply multiplied by one. The same logic could be applied to other types of generation utilizing water from a water body with no fish present.

In the 2005 report this modifier simply assessed the presence, or absence, of fish in any water body that would be impacted by a generation option. Because it was assumed that all water bodies in Ontario contained fish, a multiplier of one was applied to all water use impacts. In this report, the default assumption for all Ontario generation options that have water use impacts remains that they will impact water bodies that contain fish or other important aquatic biology. However, it is also recognized that it is possible that water use could occur in such a way that no fish are impacted. For example, if water is supplied via a municipal water system or if the generation option is placed on a body of water with no fish present. The latter is possible in a situation such as for a pumped storage hydroelectric option wherein the water reservoir and outfall pool have been artificially created[4]. The corollary situation also exists where a system could be designed such that impacts to fish are expected to be particularly high such as a small lake in a relatively closed system that contains a sustenance fishery or species at risk. To account for these situations, three categories were developed for this modifier with associated multiplier values defined based on professional judgement. These categories are presented in Table B.6.

TABLE B.6
MODIFIER CATEGORIES AND MULTIPLIERS FOR PRESENCE OF AQUATIC BIOTA

Category	Definition	Multiplier
1	Expected impact on a fish or fishery	1.5
2	Fish present	1
3	No fish present	0

With respect to application of this modifier, the default value (category 2) should be applied to all generation options and categories 1 and 3 modifiers should only be applied on a case specific basis. In particular, the application of category 1 may be difficult to determine. Similar to the quality of land impacted or lost modifier, it is not possible to say whether all cases within a generation option have the similar potential to impact aquatic biota. For example, a natural gas

[4] It is noted that even an artificially created system free of aquatic biota can become populated over time. However, for the purposes of this report we have assumed that any water system that has been created with the express purpose of electrical generation does not contain aquatic biota.

CHP station with air cooled condensers could use water from a municipal system (category 3), from a large system like Lake Ontario (category 2) or even from a small lake populated with a unique and sensitive fish species (category 1).

B.3.2 Changes to Water Quality

The intention of this modifier is to account for potentially harmful changes to the water quality during use, such as temperature, dissolved oxygen or the addition of chemicals. Because this modifier implies that the water is returned to the same source from which is drawn, it is only applicable to generating options with flow through water use which, for this document, constitutes thermal and nuclear generating stations with once-through cooling water systems as well as hydroelectric generating stations. To estimate the potential impacts of changes in water quality, it is assumed that these impacts are biological and could be cumulative. Therefore, the impacts of a change in temperature, while potentially benign, may become lethal if combined with changes in dissolved oxygen or through the addition of chemicals. However, it must also be recognized that water discharge, with respect to quality, is closely regulated by both Environment Canada and Ontario's Ministry of the Environment. As such, any potentially harmful discharges will require permits. Because harmful discharges are plant specific, this modifier was not applied in the 2005 report. However, because more site specific information is available for this report, three categories of potential impact have been defined and are presented in Table B.7 along with their associated multiplier values that have been developed based on professional judgement.

TABLE B.7
MODIFIER CATEGORIES AND MULTIPLIERS FOR CHANGES TO WATER QUALITY

Category	Definition	Multiplier
1	• some potential for changes to physical water quality • some potential for changes to chemical water quality	1.5
2	• minor potential for changes to physical water quality • minor potential for changes to chemical water quality	1.25
3	• no potential for changes to physical water quality • no potential for changes to chemical water quality	1

For the purposes of this modifier, the terms used in Table B.7 are defined as:

Physical water quality: includes physical characteristics of water such as temperature, turbidity and dissolved oxygen.

Chemical water quality: alteration of water quality through the addition of chemical substances such as contaminants like flocculants, pesticides and herbicides.

Some: effects are definable and may still exist after mitigation for example loss of habitat at water outfall due to scouring.

Minor: effects are definable but generally mitigated. For example, dissolved oxygen levels in water below hydroelectric stations that is mitigated through spillway control during spawning periods.

Application of this modifier will require site specific and potentially plant/technology specific information. Further, because water quality is closely regulated at both the provincial and federal level, impacts at even existing stations are likely monitored and mitigated. As such, for the purposes of this report, this modifier has been developed and can be applied when more information is available.

B.3.3 Utilization of Water Use Modifiers

B.3.3.1 Presence of Aquatic Biota

Application of the modifier for the presence of aquatic biota is similar to that for the quality of land impacted modifier; it must be applied at the individual generation station siting level. Note that water use for transmission is assumed to be zero in this report. Because this modifier can not be applied across either entire IESO defined zones or across an entire electrical generation option category, the user must have some knowledge of the system and where siting is or will be located. Unlike the land quality modifier however, the application of category 1 defined in Table B.6 is to some degree subjective since it requires the user to determine whether a fish or fishery could be impacted by the pressure of additional water use. The application of category 3 defined in Table B.6 is less subjective because it is based on water being drawn from a system without fish present such as a municipal water source, groundwater or a human-made body of water. In all cases where site-specific information is not available, category 2 defined in Table B.6 with a multiplier value of one should be assumed.

If it is determined that this modifier should be applied, the equations in section 4.1.4 become:

Modified Flow through Water Use (m^3/year) = ABm * Flow through Water Use (m^3/MWh)
* Electrical production (MWh/year)

Modified Consumption Water Use (m^3/year) = ABm * Consumption Water Use (m^3/MWh)
* Electrical production (MWh/year)

where ABm is the appropriate multiplier from Table B.6 for each generating station in each electrical resource option.

The modified emission totals are then summed across the components of each electrical resource option, then across all electrical resource options to calculate a total modified value for water use. Caution must be exercised that this value not be represented as absolute.

B.3.3.2 Changes to Water Quality

Changes to water quality modifier also requires the user to have knowledge of the generating station siting as well as knowledge of the source water body. As an added complication, some knowledge of the plant technology that uses water is also required. Further, it is expected that water quality issues will be closely regulated by both Environment Canada and the Ontario Ministry of the Environment. As such, it is recommended that this modifier not be applied unless specific information regarding expected changes to water quality is available. If such a situation occurs, the equations in section 4.1.4 become:

Modified Flow through Water Use (m^3/year) = WQm * Flow through Water Use (m^3/MWh) * Electrical production (MWh/year)

Modified Consumption Water Use (m^3/year) = WQm * Consumption Water Use (m^3/MWh) * Electrical production (MWh/year)

where WQm is the appropriate multiplier from Table B.7 for each generating station in each electrical resource option.

The modified emission totals are then summed across the generating stations of each electrical resource option, then across all electrical resource options. Caution must be made that these values not be presented as absolute values.

B.3.3.3 Application of Both Water Use Modifiers

Should the situation arise that both water use modifiers are applied to a generating station, the equations from section 4.1.4 would become:

Modified Flow through Water Use (m^3/year) = ABm * WQm * Flow through Water Use (m^3/MWh) * Electrical production (MWh/year)

Modified Consumption Water Use (m^3/year) = ABm * WQm * Consumption Water Use (m^3/MWh) * Electrical production (MWh/year)

where both ABm, the aquatic biota presence multiplier from Table B.6, and WQm, the water quality multiplier from Table B.7, are applied at the level of the individual generation station.

The modified values are then summed to create a total for each electrical resource option (for example, natural gas CHP) then across the options for a water use total in modified cubic meters per year. Caution is advised because this value is not an absolute value.

B.4 SOLID WASTE MODIFIERS

B.4.1 Permanence of Waste Storage Facility

The intention of this modifier is to consider the permanence of a landfill facility or a long term storage facility associated with a generation type. Wastes produced by an electricity resource option will either be disposed in a landfill (ash, gypsum), or stored in a long term waste facility (used radioactive fuel bundles and low and intermediate waste).

From a land use perspective, both an engineered landfill and an intermediate or long-term storage facility for radioactive materials, impairs land use over the long-term. A closed landfill site can be vegetated to provide wildlife habitat, as can the land above the below ground storage facility and the associated above ground buildings. Thus, it is assumed that neither a landfill nor a long-term storage facility site will be available for use in Ontario other than to provide wildlife habitat or for recreational purposes. As such, it is not possible to distinguish between the permanency of the two waste disposal facilities and no modifying factor will be applied.

B.4.2 Waste Toxicity

Wastes generated at nuclear, coal and even biomass generating stations have the potential to constitute a deleterious substance, potentially harmful to humans or the natural environment.

In a waste management report published in 2006, the Canadian Nuclear Safety Commission (CNSC, 2006) suggests a rationale for assessing the future impacts that may arise from radioactive waste. This rationale was adapted to provide a simple qualitative comparison to illustrate the relative potential impacts arising from wastes generated at a nuclear, coal and biomass generating station. Comparison results are presented in Table B.8.

TABLE B.8
COMPARISON OF LIFETIME IMPACTS OF
WASTE GENERATED DURING ELECTRICAL PRODUCTION

Waste Type	Lifetime Of Hazardous Contaminants	Operation Period Of Waste Management Facility	Duration Of Passive And Active Controls
Nuclear Waste: Low and Intermediate Level	Long term	Above ground, 10s of years to 100 years; Intermediate depth caverns, 10s of years to 100 years.	Few hundred years.
Nuclear Waste: Used fuel Interim and Long-term Disposal	Very long term	10 years in water filled pools at reactor site; 50 or more years in dry storage containers at reactor sites or central storage facility; Long term disposal in underground caverns.	Very long term, 100s to 1000's of years. Including monitoring, surveillance, maintenance, land use restrictions and markers
Coal Waste (landfilled)	Long term (metals)	10s of years	Greater than 100 years
Biomass Waste (landfilled)	Long term (metals)	10s of years	Greater than 100 years

The toxicity associated with waste from a coal or biomass generating station is a matter of the concentration of trace contaminants present in the source fuel being concentrated in residues remaining after combustion to generate electricity. Metals and radionuclides found in coal and biomass get concentrated in the waste slag and ash because they are non-combustible. As an example, uranium can be found in coal at variable concentrations depending on the source of the coal, but usually at least at concentrations of 5 parts per million (ppm) or higher in many coals. This means that if one million units of coal containing 5 units of uranium are used to generate electricity, the remaining ash will be concentrated in uranium. This can be illustrated as follows: assuming that the uranium, originally at 5 ppm, is now concentrated in the non-combustible ash assumed at 5% (or 50 000 units of the original 1 000 000 units of coal) the uranium rather than being distributed in the 1 000 000 units of coal will now be distributed in the 50 000 units of ash remaining after combustion. This means that the uranium concentration is now 5 parts in 50 000 parts or 100 ppm. The uranium concentration in this hypothetical situation is now 20 times greater than in the original coal. A similar concentration effect is expected for all non-combustible constituents of the coal, including metals, heavy metals and radionuclides and the same process is applicable to biomass combustion. This ash, from either coal or biomass, or some portion of it, is then disposed in a landfill and these concentrated constituents are also landfilled.

There are two general types of waste generated at a nuclear generating station: low and intermediate level radioactive waste and used fuel bundles. Low and intermediate-level radioactive waste that is produced during the operation of Ontario's reactors is stored centrally at OPG's Western Waste Management Facility.

Low level waste (LLW) consists of common industrial items that have become contaminated with low levels of radioactivity during routine clean-up and maintenance at the nuclear generating stations and consists of mops, rags, paper towels, temporary floor coverings, floor sweepings, protective clothing, and contaminated hardware. Where possible, the LLW is processed by either compaction or incineration to reduce the volume and the space required for storage and disposal. Wastes that can neither be compacted nor incinerated are stored as received without processing. LLW is stored in a variety of stackable carbon-steel containers and these containers are stored in warehouse-like structures, known as Low Level Storage Buildings.

Intermediate level waste (ILW) consists of ion exchange resins, filters and irradiated reactor core components. ILW wastes are currently stored in concrete- and steel-lined structures constructed in augured boreholes, in concrete-lined and covered trenches, and in concrete above-ground structures. However, these latter structures are no longer receiving waste. In the future, it is anticipated that the LLW and ILW will be transferred to a deep geological repository for long-term management (Heystee and Jensen, 2005).

After removal from the reactor, used fuel continues to produce intense gamma radiation and decay heat. Current practice in Canada is to allow used fuel (i.e., fuel which has been irradiated in a reactor) to cool in water-filled pools for about ten years and then to transfer the fuel to above-ground dry storage containers for intermediate term storage at the reactor site. The current design life of dry storage containers is 50 years, but the actual life of dry storage containers is thought to be 100 years or more. Eventually, used fuel will be transferred to underground caverns for long-term management.

Potential for deleterious effects exist for waste either from coal and biomass or from the nuclear fuel cycle. The primary difference between ash waste and nuclear waste is the need for secure containment of nuclear waste.

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JUN 27 2007

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June 23, 2007

Mr. Amir Shalaby
Vice President, Power System Planning
Ontario Power Authority
120 Adelaide Street West
Suite 1600
Toronto, ON, M5H 1T1

Dear Mr. Shalaby:

Subject: Peer review of "Supplementary Environmental Impacts Report for the Integrated Power System Plan"

I have carried out a peer review of the "Supplementary Environmental Impacts Report for the Integrated Power System Plan" (dated June 2007) that was prepared by SENES Consultants Limited for the Ontario Power Authority. This review has not involved replicating the data in the report, but rather has focused on the reviewing the approach and methods employed, the data utilized, and the meanings and reasonableness of the results.

I found the report to provide a sound and well thought out study of the direct environmental emissions of the operating phase of a wide variety of electrical power generating options for Ontario, including in some cases new electrical transmission facilities. A reasonable approach is used in the study where emissions for the province, which is a large system, are sought. The report does not dwell excessively on details where they do not affect the provincial data significantly, but stays focused on information important at the provincial level.

The type of study carried out is difficult to perform because it is often difficult to obtain data and, when data are obtained, it is difficult to ensure the data from different sources are comparable. Where necessary, the report makes reasonable simplifications and uses alternative data sources appropriately to assemble relatively complete data sets that are representative of the situation in Ontario. Where data does not exist or is not readily obtainable, reasoned professional judgement is applied by the report authors to estimate environmental emissions.

A good range and number of references and information sources have been considered and utilized within the report, in attempt to gather appropriate data and results on environmental impacts for the power generation options.

Some additional detailed observations that I made while reviewing the report follow.

- The array of electrical generation options considered is reasonable, and appears to account for the options likely to be important in Ontario in the future.
- The way in which the different power generation options are assessed is reasonable for the situation in Ontario, and the accounting for the environmental impact associated with new transmission facilities increases the meaningfulness of the results.
- The separation of water use into "water consumption" and "flow-through water use" allows the environmental impact of water use to be understood better than if all water uses were lumped together.

The report addresses electricity production via cogeneration in a reasonable and interesting manner. Cogeneration is difficult to deal with in a study such as this because a cogeneration system produces not just electricity, but also a co-product: useful heat. The difficulty in assessing the environmental emissions for cogeneration arises when one tries to determine whether all or only a portion of the emissions should be attributed to the electrical product. In this report, both methods of attributing emissions to the electrical product from cogeneration systems are considered, thereby providing a reasonable range of values for readers to consider. Which data are considered more pertinent will depend most likely on the uses for the product heat.

Table 3.1 provides a very concise summary of the results of the report and is interesting and useful. Readers of the report are cautioned, however, that they should not focus on Table 3.1 alone. Rather, they should read the subsequent sections of the report, where groups of data from Table 3.1 are presented and explained carefully, so that they gain a more complete understanding and appreciation of the data summarized in Table 3.1. The sections of the report following Table 3.1, including Appendix A, provide greater descriptions and justifications for the data presented in the report. For instance, in Table 3.1, solid wastes simply present data in mass units (tonnes) without differentiating between the type of material represented, while further on in the report, the nature of the different solid wastes (ash, spent nuclear fuel, toxic substances, etc.) are detailed.

The report acknowledges that simply examining data is one step in appreciating the impact of environmental emissions, and clearly points out that emissions data need to be weighted relative to impact criteria (e.g., human health, animal health, plant and land harm, cost) to allow a better understanding of the impact to be developed. An interesting set of weighting factors are proposed in the report based on a range of impact criteria, and these could be useful in subsequent studies although other weighting factors could also be introduced depending on the criteria considered most important by an assessor. Other weighting factors could also be used, and different individuals, agencies and countries often disagree on the magnitudes and types of weighting factors that are correct.

The report has some limitations, which are acknowledged within it:

- The report does not address emissions associated with the full life cycle of the power generation options considered, as stated in the report. A full life cycle assessment was not within the scope of the study.
- Not all types of gaseous environmental emissions are considered. However, many of the most important emissions are considered, thereby allowing a good picture of the relevant environmental emissions to be obtained for the power generation options for Ontario.

The report provides a good foundation for future assessments and research that could involve the following or other activities:

- build upon the environmental impact data provided in the report so as to determine other environmental information (e.g., the effect of introducing an emission abatement technology), and
- extend the environmental impact data so as to make it more comprehensive as more reliable data become available (e.g., by considering additional environmental pollutants such as carbon monoxide, volatile organic compounds and ammonia).

Sincerely,

Dr. Marc A. Rosen

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