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August 1, 2008

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

RE: EB-2007-0707 Prefiled evidence Report # 1 of GEC-Pembina-OSEA

Dear Ms Walli,

I enclose three copies of the prefiled evidence prepared by Mr Paul Chernick et al. from Resource Insight Inc. on behalf of the Green Energy Coalition, Pembina and OSEA. It has been uploaded to the Board's RESS site and sent to all the parties by email as well.

Sincerely,

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

encls.
EC: All participants

Green Energy Coalition

EB-2007-0707
Exhibit L
Tab 8
Schedule 1

BEFORE THE ONTARIO ENERGY BOARD

IN THE MATTER OF sections 25.30 and 25.31 of the Electricity Act, 1998;

AND IN THE MATTER OF an application by the Ontario Power Authority for review and approval of the Integrated Power System Plan and proposed procurement processes.

Green Resource Portfolios

Development, Integration, and Evaluation

by
Paul Chernick
Jonathan Wallach
Richard Mazzini
Resource Insight Inc.

Filed August 1 2008

prepared for:
Green Energy Coalition
(David Suzuki Foundation, Eneract, Greenpeace Canada, Sierra Club of Canada, World Wildlife Fund Canada)
Pembina Institute
Ontario Sustainable Energy Association

Resource Insight, Inc.

Green Resource Portfolios

Development, Integration, and Evaluation

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Richard Mazzini

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I. Summary and Conclusions

This evidence, with other evidence filed by GEC-Pembina-OSEA, reviews aspects of the Integrated Power System Plan (IPSP) prepared by the Ontario Power Authority (OPA) and develops approaches to power supply that would be less expensive, less risky, and more environmentally benign than OPA's recommendations.

A. The Integrated Power System Plan

There are five categories of major flaws that have plagued the development of the IPSP. First, OPA started with several unreasonable input estimates and assumptions. In terms of direct effects on the analysis, the most serious of these errors relate to the costs and performance of nuclear resources. Understating the costs and overstating the reliability and load-carrying capability of new nuclear resources led OPA to support construction of uneconomical new nuclear capacity and to forego cost-effective Conservation and Demand Management (CDM) and renewables.

Second, OPA does not systematically select resources to minimize costs or environmental impacts. For example, instead of selecting the maximum amount of feasible and cost-effective CDM, OPA assumes a lower value—one that barely complies with Government directives.

Third, OPA understates or ignores the benefits of dispersed local resources located close to load, such as CDM and community-scale energy systems, particularly waste-energy recycling, CHP, small wind, and biogas. Those benefits include avoiding transmission-and-distribution investments, reducing line losses, improving local reliability, and (for CHP) providing thermal energy.

Fourth, OPA takes an unnecessarily constrained view of the power-planning process. For the most part, OPA seems to see itself as a buyer of resources, with limited ability or interest in directing the province's energy future.[1] The OPA's level of effort to procure CDM is inconsistent throughout the timeframe of the plan, targeting the minimum allowed by Directive despite acknowledging higher potential and cost-effectiveness. In estimating the need for capacity reserves as insurance against generation construction delays, OPA acts as if it were powerless to influence the timing of resource construction. With respect to CHP and recycled energy, OPA is waiting for someone else to develop the resource, and has not even bothered surveying potential development sites.[2] Taken as a whole, OPA's attitude towards its planning function leaves it more in the largely passive role of purchasing resources proposed and promoted by others, rather than the manager of the province's energy future, empowered to guide and even drive markets where they are not responding efficiently and effectively.

Fifth, OPA sometimes makes decisions regarding modeling and planning that lead to outcomes quite different than OPA's stated goals. One important chain of errors starts with OPA's decision to plan for very high reserve margins, on the grounds that its procurements are likely to be unsuccessful and (more realistically) that its nuclear resources are likely to perform worse than OPA's plan. Rather than meeting these contingent needs with contingent resources—mothballed coal plants, options to accelerate CHP construction schedules, early permitting and site preparation—or with CDM and renewable procurement that exceeds the Directive minima, OPA chooses to keep the coal plants operating longer than would otherwise be required. And once OPA decides that the coal plants should be in operation, its modeling of the IPSP dispatches them primarily to serve the export market. So what started with OPA's expressed

[1]At times, OPA is a little more assertive, coordinating the timing of transmission and generation for remote wind and hydro, and discussing the geographical distribution it would seek for gas generation.

[2]For wind, OPA has been a bit more proactive. Nonetheless, OPA assumes that half the capacity of each identified wind site will not be developed, regardless of the site advantages. Again, OPA assumes no responsibility for achieving the least-cost outcome.

concern about meeting planning contingencies becomes a justification for operating the most polluting plants in Ontario to serve the export market.

Even more important problems result from OPA's nuclear-centric analysis. The OPA acknowledges that the poor reliability of the nuclear plants increases the required reserve margin, but never treats those higher reserves as part of the cost of the nuclear resources. Similarly, OPA treats minimum-generation situations (when the minimum level of output of plants exceeds load) as problematic for wind generation, but ignores the minimum-generation problems of its large nuclear portfolio. The OPA recognizes the difficulty in controlling the schedule for Bruce A restart and refurbishment, and increases the reserve requirement to compensate for that risk, but does not include similar reserve increments in the costs of planned nuclear resources. Every nuclear problem—high forced outages, operating inflexibility, construction difficulties—is attributed to other resources or spread over all resources. The OPA does not include any of these costs in its estimate of the cost of nuclear resources.

Nuclear power plants—in addition to high construction and operating costs—have long lead times and construction periods, and safety regulation makes the timing of plant completion (or restart, refurbishment or even just return from a maintenance outage) far riskier for nuclear than other resources. The large size of nuclear units (and the tendency of multiple units at a station to be affected by a single event) compounds the risk and inflexibility of nuclear investment. Ontario is exposed to much more supply risk in the event of the outage of a 500–1,600 MW nuclear unit, its failure to reach commercial operation, or return to operation after major maintenance or refurbishment, than would be the case for a 2 MW wind turbine, a 50-MW biomass plant, or a few-hundred-MW gas or CHP plant.

Nuclear capacity is also much less flexible than most other resources. If OPA finds it has 300 MW more gas, wind, hydro, biomass, waste energy or CHP in the pipeline than it needs three or four years in the future, very little is likely to have been spent on those plants, and deferring them should be easy and inexpensive. In contrast, design, procurement, and construction of a nuclear plant would be well underway, with about half its direct costs expended; delay would be difficult and expensive. And reducing the supply plan by 300 MW of renewables, heat recovery or CHP would usually involve delay of several units until they are needed. If the 300 MW excess is nuclear, it would be just a third of an 880 MW Darlington unit refurbishment, or a fifth of a 1,600 MW new nuclear unit, forcing OPA to continue with the entire unit or delay the entire unit.

The large amount of nuclear capacity that OPA has included in the IPSP, if achieved, would crowd out renewables. This competition is most clear in OPA's decision to limit wind generation, due to concerns about minimum generation levels and possible shortfalls of maneuverable thermal and hydro capacity to cover variations in wind outputs, while planning for nuclear capacity that creates massive problems with minimum generation and sharp reductions in generation. The IPSP's additions of non-maneuverable nuclear capacity contribute to OPA's limitation of wind development. The IPSP approach also includes commitments to massive amounts of nuclear capacity a decade before it is expected to be needed. As Ontario's experience with Darlington illustrates, less-than-anticipated load growth (or greater-than-expected market-generation activity) can eliminate the need for these large commitments well into their construction, leaving the province with the choice of suspending construction or suppressing renewables and even CDM. Once the nuclear units are complete, or nearly so, Ontario may find that there is little value for additional renewables and CDM, even if those resources are much less expensive than the nuclear resources (the costs for which would then be sunk).

B. Green Resource Portfolios

We started our portfolio development by reviewing and as necessary correcting OPA's assumptions and projections. Our major corrections involved estimates of nuclear cost, CDM savings, and cost-effective wind potential.

We then constructed a spreadsheet model to compute the load-carrying capability of a portfolio, estimate the dispatch of resources, compute excess generation, and compute annual portfolio costs. With this model, we estimated the cost and performance of OPA's proposed portfolio, both with OPA's high levels of exports and with exports limited to excess generation, correcting for OPA's unrealistic assumptions for nuclear capital costs.

We constructed green resource portfolios with priority on CDM and renewables, rather than OPA's planned nuclear resources. The high costs of nuclear preclude inclusion of new nuclear units.

Our analysis was conservative—in the sense of understating the potential for and benefits of our preferred resources—in the following ways.[3]

- We used the IPSP's projections of existing and committed capacity for almost all resources, adding only 400 MW of large solar projects contracted by the OPA since the IPSP was prepared.
- We used OPA's planned capacity for hydro, biomass and CHP, even though the evidence of Thomas Casten indicates that much more CHP should be available. We also used OPA's estimated 67% CHP capacity factor, rather than Mr. Casten's 80%.
- We did not include any of the waste-heat-recovery generation estimated by Mr. Casten.
- We did not include in the cost of nuclear resources the nuclear insurance cost estimated in the evidence of Gordon Thompson, or the costs of nuclear waste disposal, fuel and decommissioning estimated in the evidence of Marvin Resnikoff. Including these costs, and realistic estimates of OM&A, capital additions, capacity factor, and load-carrying capability, even existing nuclear resources may not be cost-effective to continue operating.
- We limited wind capacity to 10,000 MW, even though we have not seen any demonstration that integrating additional wind would be particularly difficult. We did not include additional wind that may be feasible with storage (as described in the evidence of Tim Hennessy) or with inter-provincial energy exchanges and firming through contracts with Quebec or Manitoba.
- We did not add to the CDM potential the reductions in energy usage and peak loads achievable by providing customers with better price signals.

Even with these conservatisms, the resulting Green Portfolios require no new nuclear resources and are more diverse, less risky, more reliable, more flexible,

[3] Our use of OPA's assumptions does not indicate that we prefer those values to the alternative values provided by our colleagues. We used OPA's assumptions to focus our analysis on specific coal and nuclear issues, to provide very conservative results, and to accommodate the tight time constraints we faced in developing this evidence. Our lack of access to OPA's models compounded the time constraints, by requiring us to reverse-engineer inputs and assumptions that OPA could have easily provided. In some cases, we do not have detailed information on cost and potential, due to OPA's apparent failure to characterize, quantify, and procure resources.

lower cost and cleaner than the IPSP portfolio. At OPA's preferred 4% discount rate, we estimate that the present value of the costs of the OPA Reference Case is $21 billion—or 32%—more than that of our Green Base Case. The reduced reliance on nuclear in the Green Portfolios also moderates the safety and environmental risks posed by nuclear power.

Despite less reliance on nuclear, the Green Portfolios have less greenhouse-gas emissions than the IPSP. In the worst case, were all the planned additions we have designated as clean energy to be SCGTs and CCGTs, rather than low-emission CHP or zero-non-emission renewables and waste-energy recovery, the Green Portfolio greenhouse gas emissions would still be comparable to those of the IPSP. With additional wind, CHP, recycled energy, CDM, and savings from pricing signals, emissions with the Green Portfolio would be considerably lower.

We have also used OPA's nuclear performance assumptions, and like OPA have treated the remaining life of existing nuclear and (in the OPA cases) the in-service dates of planned nuclear resources as deterministic in modeling portfolios. In its insurance analysis, OPA recognizes that the in-service date for restarted and refurbished nuclear units are subject to delay, multiple units may be forced offline for years at a time, and that existing units may be retired earlier than scheduled. One year of unanticipated lost operation of a Pickering unit (due to a delayed operation, prolonged outage, or early shutdown) could add 3 million tonnes of GHG emissions, if the replacement energy comes from Ontario or Midwestern coal plants. The additional GHG emissions would be twice that for a lost year for a Darlington unit, and even more for the very large proposed new nuclear units. Hence, the OPA case, with its additional nuclear units, will probably result in higher emissions than we have modeled.

C. Recommended Improvements in OPA Planning

Our analysis suggests that OPA should be required to improve its planning in the following ways:

- Use more realistic estimates of the costs and performance of nuclear resources.
- Recognize the continuing technical progress in renewable energy.

- Assume a more-active stance managing the province's energy future, identifying, characterizing and designing procurement processes to secure low-cost, low-impact, and market-transforming CDM and generation resources.
- Seek out and quantify the full potential for preferred resources, minimizing and explaining differences between potential and planned acquisitions, and between planned and achieved procurement.
- Realistically assess the capacity insurance required.
- Identify any high-impact resources—most importantly the coal plants—needed solely for insurance against long-term contingencies (delayed in-service dates, prolonged outages, early retirement), and reduce emissions by maintaining those resources in cold standby until they are needed for reliability, if ever, or they reach the legislated end of service.
- Do not operate the coal plants for exports.
- Analyze the effects of the planning inflexibility of any large long-lead time resources that remain in the plan (such as the IPSP's planned nuclear stations), in the event of reduced load, emerging technology problems, and emergence of preferred resources.
- Implement a loading order for resource additions, starting with CDM and then adding, as needed, community-scale renewables, waste heat recovery and CHP; large and/or remote renewables (with associated transmission and storage, including interconnection to neighboring provinces), larger CHP and waste-energy recovery; and efficient gas-fired generation.

II. Overview of Study Approach

This analysis compares the expected costs of the Integrated Power System Plan (IPSP) against those of alternative resource portfolios that comprise more renewables and conservation and demand-management (CDM), less nuclear capacity, and earlier shutdown of the coal plants. We derive estimates of costs and performance for a variety of demand- and supply-resource options. We then use these estimates to develop resource plans that economically and prudently satisfy Ontario's reliability and energy requirements, while complying with government directives and regulations. Using a spreadsheet model developed for this analysis, we forecast annual costs associated with the IPSP and with a number of "green power" portfolios.

In order to satisfy reliability and energy requirements, these Green portfolios include new clean resources in addition to renewable resources and CDM. To simplify the analysis, we model these generic new resources as simple-cycle gas turbine (SCGT) and combined-cycle gas turbine (CCGT) capacity. However, these new gas units are used simply as proxies for potential clean technologies, such as community-based dispersed renewables, Ontario central-station renewables, imports of hydro and wind resources from Manitoba and Quebec, combined heat and power (CHP, including district energy systems), recycled energy, and storage. Modeling these clean resources as gas-fired generation understates the benefits of the Green portfolios, such as the transmission and distribution costs and losses avoided by local, customer-sited technologies, co-production of thermal energy, and reduced emissions.

The Ontario Power Authority (OPA) segregates resources into three categories: existing, committed and planned. For the most part, we accept OPA's characterization of existing and committed resources, filling in missing assumptions as necessary. We also revise the capacity of committed solar to reflect OPA commitments since the preparation of the IPSP.[4]

Critically, we reject OPA's characterization of plans for potential new nuclear generation at Darlington and for replacement or refurbishment of Bruce B as committed resources. Simply put, we take a different view of government statements than OPA does. In Exhibit I-22-87, OPA declares that the Infrastructure Ontario and Ministry of Energy statements narrowing the nuclear RFP sites to Darlington and expressing support for continued nuclear generation at Bruce constitute commitment to those resources, citing an Infrastructure Ontario Press Release.[5] We read the public statements as expressions of general policy intentions that have yet to be tested for economic and technical feasibility. Accordingly, the proposed nuclear projects should not be treated as committed and unavoidable.

Many of the characteristics of existing and committed resources are irrelevant to the planning decisions before the Board. The sunk costs of resources are inherently irrelevant. So long as a resource is in place for the same period in all plans, its future capital costs and fixed OM&A are also irrelevant, since they will be the same in all plans. For most existing and committed resources, our cost model thus includes only fuel and variable OM&A. The only existing resources for which we include fixed OM&A costs are the coal plants, since those are retired in different years in alternative plans.

When forecasting portfolio costs, we include only those transmission costs that OPA has identified as required to integrate wind and hydro generation. We assume that the costs of all other transmission would be the same in all cases.

In our analysis, we use OPA's pre-CDM load forecast, although this may be overstated.[6] We also adopt most of OPA's resource assumptions, as described further in Section IV. Our adoption of OPA estimates for purposes of modeling does not mean that we view these assumptions as correct. We view many of

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[4] We did not make similar adjustments for other renewables and CHP, even though OPA has also contracted for additional capacity in those categories.

[5] "Phase 2 of Nuclear RFP Latest Step in Ontario's 20-Year Plan to Bring Clean, Affordable and Reliable Electricity to Ontarians," Infrastructure Ontario Press Release, June 16 2008.

[6] On this point, see the evidence of Ralph Torrie filed by GEC-Pembina-OSEA.

those assumptions as understating the potential for green resources. Like OPA, we express costs in 2007 Canadian dollars and present-value annual costs to 2007.

In addition to the financial benefits that we quantify, the resource mix we develop has important benefits that are difficult to monetize, including planning flexibility, short lead times, and reduced vulnerability to industry-wide safety-related nuclear shutdowns. The first two characteristics are particularly valuable in the face of the significant likelihood of lower-than-expected load growth and continuing technological change.

III. Critique of the Integrated Power System Plan

We critique various IPSP input assumptions and analytical approaches throughout this document. The following sections address problems in OPA's broader planning approach.

A. Planning Process

The Ontario Power Authority interprets the requirement in the Supply Mix Directive to obtain 6,300 MW of CDM by 2025 as a planning ceiling, rather than a floor. While OPA concedes that additional CDM may be cost-effective, it does not include additional CDM in the IPSP. As explained in the evidence of Scudder Parker, filed by GEC-Pembina-OSEA, OPA does not even include all the cost-effective CDM its own studies identified.

The OPA also assumes unrealistic and subsidized financing for generation resources. OPA capitalizes all investment costs using a 4% finance rate, equivalent to the cost of debt for provincially-supported entities, such as Ontario Power Generation (OPG), without any allowance for the costs of actually financing the costs over the plant's useful life. Most of OPA's generation acquisitions (renewables, CHP, CCGT and even the restart of Bruce 1 and 2) have actually been financed at market rates, with the construction and operating risks largely internalized by the developer.[7] Real market-based generation

[7] The contract for refurbishment and operation of the Bruce units does transfer some of these risks away from the developer/operator, obscuring the true cost of that effort.

resources—even if they sell to OPA under a fixed-price power-purchase or tolling contract—require equity in their capital structure to absorb the risks of cost overruns and poor performance. Financing generation entirely with debt (or equity at artificially low cost) hides the risks from the economic analysis, and transfers the risks to consumers or taxpayers without quantification.

Based on the analysis of nuclear overnight construction costs in the evidence of Jim Harding and the nuclear insurance subsidy in the evidence of Gordon Thompson (both filed by GEC-Pembina-OSEA), and of nuclear OM&A, capital additions, operating life, and cost of capital in this evidence, we conclude that OPA has dramatically and critically under-estimated the cost of new nuclear resources.

Inexplicably, the IPSP does not compare the costs of its preferred cases against cases with less nuclear capacity (such as Case 3 in Exhibit G-1-1). OPA only compares the costs of a few pairs of individual resources in various exhibits.[8] In Exhibit D-3-1, Attachment 1, OPA compares the costs of gas and nuclear resources at various capacity factors and estimates the amount of nuclear capacity that would be cost-effective and prudent for supplying baseload output requirements. That analysis uses OPA's understated nuclear costs and ignores Ontario's minimum-load problem and the existence of other baseload resources (e.g., run-of-river hydro and CHP), and thus overstates the feasible amount of nuclear baseload capacity. That erroneous determination of economic baseload capacity essentially determines the amount of nuclear capacity in OPA final plan.

The OPA also excludes identified renewable resources—particularly wind power—that are less expensive than nuclear resources.

B. Insurance Capacity, Exports, and Coal

Ontario Regulation 496/07 requires that OPG cease the burning of coal at all four existing coal plants by December 31 2014. The Supply Mix Directive further specifies that, prior to 2014, the IPSP should "plan for coal-fired generation in Ontario to be replaced by cleaner sources in *the earliest practical*

[8]For example, OPA compares gas to wind and hydro to wind in Exhibit D-5-1, and on-shore to off-shore wind in Exhibit D-5-2.

time frame that ensures adequate generating capacity and electricity system reliability in Ontario" (p. 1, emphasis added).

Rather than phase out the coal plants in the earliest practical time frame, OPA postulates large requirements for "insurance," which it does not allow other resources to provide, and substantially delays the deactivation of coal capacity. Specifically, the IPSP includes between 3,000 MW and 4,400 MW of additional coal capacity to meet its estimate of insurance requirements between 2009 and 2014.

The OPA's formulation of insurance requirements has a raft of problems, as follows:

- The insurance requirements identified by OPA are excessive. We are not aware of any other utilities or planning authorities that include such a large insurance reserve for delay in resource additions. The high insurance requirements are driven in part by excessive and biased allowances for uncertainty.
- In modeling the uncertainties in conservation and renewable resources, OPA reduces the expected contribution from these resources by asymmetrically assuming that shortfalls were twice as likely as surpluses (Exhibit D-2-1, Attachment 2, pp. 3–4). Specifically, OPA assumes a triangular distribution from 40% below plan to 20% above plan in each year, with no provision for delayed projects to come in later. The IPSP offers no justification for those assumptions. Also without reasonable basis, OPA further reduces the expected contribution from renewable resources by counting only half of the capacity at the large wind sites it includes in the IPSP and slightly more than half of the small wind projects in the Hydro One queue (Exhibit D-5-1, pp. 34–35).[9]

  For both large and small wind, OPA ignores steps that can be taken to address shortfalls in expected contributions, such as timely improvements to procurement processes, which would mitigate much of the uncertainly reflected in OPA's modeling.

[9]As OPA notes in Exhibit D-5-1, with respect to small wind projects, "not all of the projects for which an application to Hydro One has been made will ultimately come into service; however, additional resource applications are expected over the period of the IPSP" (p. 35, footnote 14). In that situation, OPA "assumes that these two factors will cancel each other out."

The bias in the conservation and renewable distributions increases the insurance requirement by about 250 MW in 2014, or about 12% of OPA's proposed insurance (excluding insurance for the risk of higher nuclear forced outage rates). According to Exhibit I-38-26(c), reducing the spread in the conservation distribution by half, even without correcting the bias, reduces the insurance requirement by 140 MW in 2016.

- The insurance calculation assumes an average one-year delay in planned gas-fired generation, and does not consider the possibility of capacity being brought on-line early in the event of a capacity shortfall (Exhibit D-2-1, Attachment 2, pp. 5–6). This assumption has the following consequences:
    - In essence, OPA's decision to assume a one-year average delay means that the IPSP capacity cases are not based on OPA's stated nominal forecast of gas additions (as in Exhibit D-9-1, Table 12), but a significantly lower expected forecast. This reduction is before any allowance for the risk of variation from the expected additions schedule.
    - The expected delay in gas generation built into the insurance calculation reduces the average gas capacity available by hundreds of MW in the 2010–2014 period. In 2010, the reduction is 1,475 MW; in 2013, it is 1,028 MW.
    - Through most of the 2010–2014 period, the expected delay in gas generation represents about 40% of OPA's insurance.
- The OPA did not consider accelerating CDM, gas, or renewables to meet that insurance level and phase out the coal plants in the earliest practical time frame.
- Similarly, OPA did not assume interconnection support in later years, even though that would also allow earlier coal shutdown. In Exhibit I-22-221(d), OPA explains that it is not willing to rely on interconnections beyond 2009, because

    > availability in the longer term cannot be relied upon in the absence of a firm contract. The OPA does not consider relying upon these short term availability estimates to be a prudent assumption for longer-term planning purposes.

    Had OPA simply assumed the same interconnection support in 2009 as in 2008, another unit or two of Lambton could be shut down.

- More fundamentally, OPA's logic is deficient, in that it requires the coal plants to be on line, as insurance against potential delay in various resources (CDM, gas generation, nuclear restart, or the Bruce transmission line) or long-term shutdown of an entire nuclear station. That insurance can be provided by having the coal plants in cold shutdown, available for restart in 60 or 90 days, if one of the potential adverse conditions arises.

Rather than shutting down the coal plants in the earliest practical time frame and leaving them available for restart under certain contingencies, OPA proposes to leave many additional coal units in operation, and to allow them to dispatch on an economic basis. For the most part, those coal plants would be producing energy not required to meet Ontario's loads. Case 1B of the IPSP shows projected energy exports of 20–27 TWh annually between 2010 and 2014, driven by the excess coal capacity. In our modeling of the IPSP, we find that the coal plants generate about 36 TWh during the period 2010–2014 if exports are limited to minimum-generation situations, and about 87 TWh if the coal plants are allowed to run as OPA expects. The additional 49 TWh of coal generation in the latter case serve exports.

In effect, the planning in the IPSP is driven by exports. The insurance requirement becomes an operating-capacity requirement, which (combined with OPA's constraints on interconnections and all other resources) requires the coal plants to continue to operate, which OPA does without constraint, producing copious energy for the export market. Using coal to produce energy for exports is inconsistent with the phase-out required in the Supply Mix Directive.

The coal-for-export strategy is also no longer feasible, with the May 16, 2008 amendment to Ontario Regulation 496/07, which provides that "as of January 1, 2011, the [coal plants shall] not collectively emit more than 11.5 megatonnes of carbon dioxide from the use of coal in any calendar year." This is 41% of the carbon emissions of the coal plants in 2007 (OPG, 2008b, 41). At 2007 capacity factors and emission rates, the 11.5 MT limit would only allow the operation of Thunder Bay, Atikokan, and at most four Nanticoke units, with the total shutdown of Lambton.

C. Minimum Generation Issues

In a recently completed operability study of the IPSP, the Independent Electricity System Operator (IESO 2008) identifies the problem of excess generation at low-load hours, when minimum generation levels may exceed load plus exports.

The IESO (2008, 14) describes surplus baseload generation (SBG) as resulting from nuclear, hydro (especially during spring runoff) and wind resources, and assumes the availability of only 1,000 MW of hourly export capability to absorb this excess. The IESO finds that the OPA plan would require numerous nuclear unit shutdowns to mitigate minimum generation problems.

Because of OPA's employment of large quantities of baseload generation in the IPSP, numerous occurrences of surplus baseload generation are embedded in the IPSP.[10] OPA does not acknowledge the SBG potential since it assumes that Ontario can export large amounts of energy at all times, limited only by regional transfer capability. Accordingly, in the OPA view, whenever an SBG condition exists, the surplus energy will simply be sold elsewhere. As a result, the OPA projects substantial exports in most years of the IPSP, particularly in those years of maximum nuclear penetration.[11] See Table 1.

[10]The OPA appears to overstate the type and magnitude of resources that contribute to SBG. In Exhibit I-22-118, OPA suggests that—in addition to nuclear, wind and some hydro—non-dispatchable capacity in the planned system would include 4,000–5,000 MW of gas, 1,250 MW of interconnection, and 3,000–7,000 MW of conservation. Each of these categories of supposedly non-dispatchable resources is overstated. Our analysis of historical operating data indicates that very little of the gas generation (even the CHP) is non-dispatchable. It in difficult to understand why an interconnection would require Ontario to accept 1,250 MW of energy at low-load hours. And OPA's forecast of non-dispatchable conservation is greater than its planned conservation at peak load, let alone the much lower amounts of conservation near minimum load.

[11]As discussed above, a portion of the exports between 2008 and 2014 are explained by dispatch of existing coal units for economic export. However, exports net of coal are still substantial.

Table 1: Generation for Export in the IPSP (TWh)

	Ontario Load[a]	IPSP Generation[b]	IPSP Exports
2008	158	176	18
2009	159	175	16
2010	159	179	20
2011	161	181	20
2012	162	185	23
2013	163	188	25
2014	164	191	27
2015	165	177	12
2016	168	178	10
2017	169	177	8
2018	171	179	8
2019	173	181	8
2020	176	186	10
2021	178	195	17
2022	181	202	21
2023	184	208	24
2024	187	209	22
2025	189	211	22
2026	192	216	24
2027	195	215	20

[a]D-3-1 p. 12 [b]D-9-1 p. 32

This assumption of a virtually infinite sink for exports masks the reality that baseload units will be unable to operate under the likely SBG conditions. The IESO (2008, Table 4) makes this clear in its assessment of the IPSP:

- "Analysis of the OPA data indicated that management of surplus baseload generation in the simulated schedules relied on significant amounts of exports." Thinking such amounts are infeasible, "the maximum export schedule was capped at 1,000 MW" by the IESO in its analysis. This compares to exports of many times that amount in the OPA data.
- With the 1,000-MW cap on exports, the IESO's analysis found many occasions where nuclear unit shutdowns were required to resolve SBG situations, including cases where even the shutdowns were not enough to resolve the issue fully. The number of annual shutdowns was estimated at an astoundingly large 77 in 2012 and exceeded 35 in several other years, worsening each year near the end of the plan period.

Surplus-generation situations are particularly onerous for nuclear units because of their inflexibility in changing load. Although the surplus may only last a few hours, the unit's output may be restricted for days thereafter because of its operational characteristics. Hence, even brief events can lead to a sizable effect on nuclear production.

Nuclear units are subjected to numerous load swings and shutdowns in the IPSP when exports are limited to a more-feasible amount. And the situation could easily become worse. There is no assurance that neighboring regions will be in a position to accept even 1,000 MW of exports from Ontario. At certain times of minimum load in Ontario, those systems are also likely to be operating near minimum generation levels.

Cycling or shutdown of nuclear units to mitigate minimum-generation constraints will likely lead to lower reliability and may raise safety issues. These units are simply not designed for frequent load changes, and to stretch them in this unintended manner is risky.

Notwithstanding such issues, the economic effects on the nuclear option deserve considerable attention by OPA. Capacity factors are sure to be smaller than OPA has predicted because of the SBG problem. OPA was asked about any such analyses (I-22-231(c)), but offered no estimates of impact.

Most importantly, OPA has stated (I-22-231(b)) that it has not consulted with the nuclear regulator, plant designers, or plant operators to determine if the large number of shutdowns and runbacks contemplated by the IPSP will even be possible or permissible.

Even were Ontario's nuclear fleet as reliable as OPA assumes, it is unlikely that the fleet will be permitted to generate at its optimum under minimum-load conditions. From an operating perspective, the Ontario system simply cannot efficiently utilize the maximum 14,000 MW allowed in the directive.

D. Lack of Documentation

We have found several apparent inconsistencies in the resource capacities presented in various documents in the IPSP filing; in OPA's stated nuclear capital cost; in OPA's categorization of resources as baseload, intermediate, or peaking; in its dispatch modeling of various resources, and in other elements of the IPSP.

The OPA has refused to provide most of its spreadsheet computations, or even the actual input and output values from its models, so we have no way to ascertain the source of these apparent inconsistencies, to determine what values (prices, outage rates, capacities, heat rates) OPA actually used for most purposes, or even to determine the scope of costs included in its analysis. Nor do we, or any other party, have any way to determine whether OPA simply made computational errors in its derivation of the IPSP.

Given the lack of documentation offered in support of OPA's analysis, the Board should treat the results of that analysis with caution.

IV. Resource Costs and Characteristics

For the purposes of our analysis, we accept most of OPA's resource assumptions, including

- its forecast of CDM through 2010;
- the type and amount of existing capacity and timing of retirement, if any;
- the type and amount of committed capacity and timing.

The following table summarizes the source of the resource assumptions adopted in our analysis, indicating whether we adopted OPA's assumptions (Y) or developed such assumptions independently (N).

Table 2: Resource Assumptions and Inputs from OPA

Resource	Capital Cost	Fixed OM&A	Variable OM&A	Fuel	Heat Rate	Planned Capacity	Capacity Factor
Biomass	–	–	Y	Y	Y	Y	Y
Hydro	–	–	–	–	–	Y	Y
Solar	–	–	–	–	–	N	Y
On-Shore Wind	Y[a]	Y	–	–	–	N	Y
Off-Shore Wind	N	Y	–	–	–	N	Y
Gas	N	Y	Y	N	Y	N	–
CHP	–	–	Y	N	Y	Y[b]	N
Nuclear	N	N	Y	Y	Y	N	N

Blanks (–) are not used in the analysis or are otherwise not applicable.
[a]with modifications
[b]See the evidence of Thomas Casten with regard to the feasibility of greater CHP capacity

The following sections describe our treatment of resource costs and characteristics and discuss to the extent to which these differ from OPA's.

A. Conservation and Demand Management

We rely on forecasts of CDM savings and costs developed by the Vermont Energy Investment Corporation (VEIC), introduced on behalf of GEC-Pembina-OSEA in the Evidence of Scudder Parker. Specifically, VEIC developed forecasts for a medium and an aggressive CDM scenario. We use the medium CDM forecast as our base case inputs. In addition, we model an aggressive CDM sensitivity based on VEIC's aggressive CDM scenario forecast.

B. Wind

Potential

The OPA estimated the wind-resource potential separately for small sites, large on-shore sites, and for large off-shore sites. For small sites, OPA estimated potential based on the total capacity of Renewable Energy Standard Offer Program (RESOP) applications currently in the Hydro One queue, as reduced to account for transmission and distribution limits (Exhibit D-5-1, p. 34). We adopt OPA's estimate of 1,148 MW of small-wind potential for analytical purposes, but note that improvements in distribution and transmission substations may allow development of much more distributed generation. The failure of the IPSP to examine the economics of such improvements and ensure their timely deployment is a serious shortcoming.[12] In our analyses, we limit the total wind capacity to the 10,000 MW level examined in Exhibit D-5-1 Attachment 2; we make up for the restriction in small wind projects by adding more capacity from large projects.

For large on-shore sites, OPA identifies potential sites of greater than 30-MW capacity throughout the province, estimates the capacity and energy production for each of these sites, estimates capital, OM&A, transmission-interconnection, and transmission-upgrade costs for each site (or for a cluster of sites), and then ranks sites on the basis of their levelized total costs per unit of energy output

[12] See also the evidence of Hermann Scheer on behalf of GEC-Pembina-OSEA, which discusses the rationale for an accelerated shift toward distributed renewable generation.

("all-in LUEC," for Levelized Unit Energy Cost). OPA estimates a large on-shore potential of almost 8,500 MW (Exhibit D-5-1, Table 16).

Similarly, OPA estimates the potential for large off-shore wind by identifying potential sites and estimating the capacity and energy output for each of these sites. However, in this case, off-shore sites are ranked not on the basis of cost, but by a variety of qualitative factors.[13] The OPA identifies a total of 34,500 MW of potential off-shore sites. The top ten ranked sites have a combined capacity of about 5,900 MW.

We adopt OPA's approach of ranking identified on-shore sites on the basis of all-in LUEC, and adopt the cost and performance assumptions underlying those estimates of all-in LUEC.[14] In addition, we extend OPA's ranking approach for on-shore sites to include the top-ten ranked identified off-shore sites. We derive an all-in LUEC for each of these off-shore sites based on estimates of capital costs for prototypical off-shore projects and OPA's estimate of OM&A and transmission costs.

Table 3 provides our combined ranking of large on- and off-shore projects. The combined potential amounts to more than 14,300 MW, with all-in LUECs that range from 7.5¢/kWh to 11.5¢/kWh.

Table 3: Ranking of Large On-Shore and Off-Shore Wind Projects

Site	**Capacity** *(MW)*	**Cumulative Capacity** *(MW)*	**Energy** *(GWh)*	**All-In LUEC** *($/MWh)*
Kingsville (D 20)	200	200	535	74.53
Port Burwell (D 21)	200	400	535	74.83
Elmira (D 24)	200	600	501	78.21
Bruce (S 36)	177	777	443	78.78
Windsor (S 31)	69	846	185	79.36
Simcoe (D 23)	200	1,046	501	80.30
Wallace (S 45)	200	1,246	486	82.67
Simcoe (D 18)	100	1,346	250	82.90
Bruce Peninsula (S 46, S 5)	380	1,726	951	82.95

[13] As discussed below, OPA did not estimate site-specific costs for off-shore sites. Instead, OPA developed generic cost estimates for a prototypical off-shore site.

[14] We rely on the all-in LUEC solely for the purposes of ranking wind projects. In contrast, we estimate annual carrying charges associated with wind capital investments for the purposes of estimating annual plan costs.

Site	Capacity (MW)	Cumulative Capacity (MW)	Energy (GWh)	All-In LUEC ($/MWh)
Picton (S 54, S 53)	292	2,018	726	83.02
Goderich (D 32, D 38, D 37, S 58)	429	2,447	1,075	83.43
Off-Shore Site 4	800	3,247	2,754	85.06
Off-Shore Site 1	410	3,657	1,414	85.27
Stratford (S 60)	123	3,780	287	85.66
Off-Shore Site 5	765	4,545	2,567	85.88
Kent (S 16)	41	4,586	110	87.40
Off-Shore Site 8	800	5,386	2,646	87.45
Larchwood (S 33)	119	5,505	283	87.49
Off-Shore Site 3	730	6,235	2,418	87.55
Off-Shore Site 9	465	6,700	1,524	88.07
Off-Shore Site 7	600	7,300	1,948	88.21
Off-Shore Site 2	405	7,705	1,315	88.95
East Lake Superior (S 30)	200	7,905	491	89.05
Off-Shore Site 6	545	8,450	1,774	89.34
Kingsville (S 1)	33	8,483	88	89.72
Stratford (S 59)	60	8,543	140	89.99
Manitoulin Group 1 (S 35, S 22)	400	8,943	952	91.38
OS 10	355	9,298	1,214	91.62
Manitoulin Group 2 (S 8, S 13, D 19, D 25)	554	9,852	1,318	92.09
East Lake Superior Group 1 (S 25, S 2)	400	10,252	982	92.76
Wingham (D 22)	36	10,288	90	92.95
Wallace (S 23)	42	10,330	102	93.09
East Lake Superior (S 17)	72	10,402	177	94.97
Northern Georgian Bay (S 43)	66	10,468	157	95.02
Martindale (S 40)	200	10,668	476	95.30
Pembroke (S 26, S 18, S 29)	207	10,875	503	95.91
Northern Superior (S 44)	200	11,075	464	96.56
East Lake Superior Group 2 (S 6, S 4)	400	11,475	982	96.59
West of London (S 57, S 52, D 26)	337	11,812	785	96.65
Fort Frances (S 56)	154	11,966	376	96.78
Parry Sound (S 28, S 15, S 38, S 41, S 49)	237	12,203	561	98.01

Site	Capacity (MW)	Cumulative Capacity (MW)	Energy (GWh)	All-In LUEC ($/MWh)
Dymond (S 48)	66	12,269	157	99.57
Thunder Bay (S 12, S 10, S 11, S 14, S 3)	604	12,873	1,475	100.18
North Bay (S 34, D 39, S 37)	402	13,275	951	100.94
Marathon (S 7)	95	13,370	221	100.94
Lakehead (S 55, S 32, S 42)	579	13,949	1,344	103.27
Alexander (S 47)	200	14,149	464	104.40
Rabbit Lake (S 51)	44	14,193	108	107.39
Pinard (S 50)	76	14,269	181	110.09
Alexander (S 39)	78	14,347	181	115.11

Annual Cost and Performance

We estimate annual prices paid for small wind generation in accordance with the current RESOP pricing mechanism. Specifically, we set the 2007 price for RESOP generation at 11.04¢/kWh. Thereafter, 80% of the 2007 price remains fixed, and the remainder escalates at the general rate of inflation.[15] We then estimate annual costs for small wind resources based on OPA's assumption that 10% of the estimated 1,148 MW potential will enter service in each year from 2011 to 2020 (Exhibit D-5-1, p. 60).

We estimate annual costs and performance for large on-shore sites based on OPA's estimates of site-specific capital, OM&A, and transmission costs, along with OPA's estimates of each site's capacity and energy output.[16] OPA assumes that capital costs remain constant in real dollars over the planning horizon. In contrast, we assume a real decline of 1% per year, based on the technical progress estimates in O'Connell, Pletka, et al. (2007, 5-6) for a U.S. Department of Energy study of wind potential.

Similarly, we estimate annual costs for large off-shore sites based on OPA's estimates of site-specific capacity and energy output, along with OPA's generic estimates of OM&A and transmission costs for prototypical sites. However, we do not adopt OPA's generic capital-cost estimate, since it is based on cost

[15]Since all costs in the RII model are expressed in constant 2007 dollars, we actually forecast prices after 2007 by keeping 20% of the 2007 price fixed and deflating the remaining 80% at the general rate of inflation.

[16]As discussed above, we include transmission costs solely for wind and hydro resources. We therefore conservatively assume that transmission costs for incorporating planned nuclear capacity do not vary between OPA and Green cases.

experience for deep-water ocean sites and thus likely overstates the costs for the shallow, fresh-water sites that are top-ranked in OPA's analysis of off-shore wind potential. Instead, we assume a capital cost of $2,600/kW based on an estimate in O'Connell, Pletka, et al. (2007, 5-6).

The RII model dispatches wind resources to match OPA's estimates of average annual capacity factors for selected wind sites. In addition, the RII model shapes monthly output to match historic monthly generation profiles, as provided in the first part of Exhibit D-5-1, Attachment 3, Figure 2. The OPA failed to provide its assumptions regarding hourly generation profiles by month for wind resources.[17] The diurnal pattern shown in the second part of Exhibit D-5-1, Attachment 3, Figure 2, indicates that output is almost flat over the day, with actual data suggesting some increase during the on-peak hours (roughly 8 AM to 5 PM). For each month, we therefore model wind output as constant across the hours of the day.[18]

Integration Constraints

The IPSP (Exhibit D-5-1, pp. 12–13) states, "With respect to wind's operational limitations, the OPA has recommended, for the present, that the development of wind resources be limited to 5,000 MW over the term of the plan." OPA cites Exhibit D-5-1, Attachment 2 (Ontario Wind Integration Study) as the source for this opinion.

The findings of the Ontario Wind Integration Study do not support OPA's recommendation for a 5,000 MW limit on planned wind development. In fact, this study finds that up to 10,000 MW of wind could be accommodated without posing significant operational problems. For example, the study concludes with regard to the impact on regulation requirements:

> The results of the regulation analysis show that the incremental regulation required to maintain the current performance is small…. [W]e believe that the impact on regulation of 10,000 MW of wind generation by the year 2020 is modest and can be accommodated with little or no changes to existing operating practices. (Exhibit D-5-1, Attachment 2, p. 74)

In contrast, OPA in Exhibit I-1-37 characterizes the results of the Wind Integration Study regarding regulation as follows:

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[17] That information should have been provided with OPA's wind and hydro profile model, which OPA has thus far refused to release.

[18] Our results would not vary substantially using a different assumption for diurnal generation, so long as wind output were not correlated with load.

> The results of the assessment suggest that the incremental regulation requirement associated with a 5,000 MW penetration of wind in Ontario is modest and could be accommodated with little or no changes to existing operating practices.

While that statement is certainly correct, OPA could have said the same for 10,000 MW, for regulation and other services.

The incremental capacity required for 10,000 MW of wind is only 18 MW of 1-minute regulation, 155 MW of 5-minute load following, and 336 MW of 10-minute reserves. In addition, the integration study indicates that a total of 7,600 MW of capacity needs to be available to ramp up in three hours. All those requirements would be met easily by the 11,600 MW of gas and oil capacity in OPA's plan (Exhibit D-9-1, Table 14), plus the thousands of megawatts of hydro resources.

The integration study does raise concerns that 10,000 MW of wind penetration may lead to excess baseload generation during minimum-load hours and may generally increase ramping requirements. However, these concerns are largely conjecture, since the integration study did not analyze whether the existing system or a system defined by the capacity mix in the IPSP could provide the maneuverability necessary to accommodate high penetrations of wind. Just as important, much of the minimum-generation or surplus-baseload generation problem in Ontario results from the large amount of nuclear capacity. Replacing some nuclear capacity with wind, clean thermal capacity, and storage would likely reduce the minimum-generation problem, not exacerbate it.[19]

In fact, the required ramping capacity identified in the integration study seems to be within the combined hydro, gas (including Lennox), import capability, and export capability of the Ontario system. Operating flexibility could be enhanced in the future by adding more centralized storage (increased capacity at existing storage hydro sites, pumped hydro, compressed air), decentralized storage (such as batteries or capacitors) near load, and/or storage at wind sites (such as compressed air).

[19]Clean thermal capacity generally follows load and would be less of a problem at low load times, storage is dispatchable, and wind can be constrained if necessary. In contrast, it is difficult to constrain nuclear output, due to safety concerns associated with repeated cycling and the long time period for restart after complete shutdown.

C. Hydroelectric

We adopt OPA's assumptions regarding the timing and magnitude of committed and planned hydroelectric additions. We estimate annual costs and performance for these additions based on OPA's estimates of site-specific capital, OM&A, and transmission costs, along with OPA's estimates of each site's capacity and energy output.

The OPA failed to provide the hourly generation profiles that would have allowed us to dispatch hydro resources in the same fashion as in OPA's modeling of the IPSP. Instead, we assume that 3,500 MW of hydro resources are non-dispatchable run-of-the-river facilities. The RII model then dispatches the remainder to follow hourly load.

D. Solar Photovoltaic

Following OPA's convention, we assume that solar-electric installations of less than 500 kW are included in CDM. We include as committed the 407 MW of larger installations that OPA has contracted under the RESOP, compiled from OPA's monthly "Progress Report on Renewable Energy Standard Offer Program" through May 2008. We note that significant progress in solar technology appears to be likely, but do not model on that basis (see the evidence of Hermann Scheer).

Consistent with OPA's modeling, the RII model dispatches solar resources at an average annual capacity factor of 12%.

E. Bioenergy

We adopt OPA's assumptions regarding the timing, magnitude, and type of committed and planned bioenergy additions. We estimate annual costs and performance for these additions based on OPA's assumptions regarding the costs and operating characteristics for bioenergy projects provided in Exhibit D-3-1, Attachment 2.

F. Coal

The only coal plants considered in the IPSP are the existing units. Since their shutdown dates and energy output vary among cases, we need estimates of fixed OM&A, variable OM&A, and fuel costs per MWh (incorporating both the cost of fuel and heat rate) to model these resources. In the absence of OPA documentations of its assumptions, we estimated these values from publicly available documents.

Fixed OM&A

We estimate the 2007 OM&A cost of the coal plants to be $81/kW-year, based on the following sources and steps:

- OPG (2008b, 2) reports 8,573 MW of fossil generation, at an OM&A cost of $66.8/kW-yr (37), or $573 M.
- Subtracting $50 M and 2,100 MW of Lennox, from Board's order on the Lennox RMR (Decision with Reasons , EB-2006-0205, January 22 2007), leaves $523 M for the coal plant OM&A and 6,473 MW of coal capacity.
- Dividing the coal OM&A by the coal capacity yields $81/kW-year.

Subtracting variable OM&A of $3/MWh, we estimate that the fixed OM&A for the coal plants to be $68/kW-year. We further assume that the coal plants could be placed in cold shutdown, available on a couple months notice, and still meet the insurance needs identified by OPA. We assume that the fixed OM&A of the plants in cold storage would be half that in operation.

Variable OM&A

We estimate that the variable OM&A for OPG's coal plants averages about $3/MWh, based on data in Ontario Ministry of Energy (2005, Tables 2-1, 4-1, and 4-8).

Fuel Costs

We derived fuel costs for Ontario's coal units based on data from the Ontario Ministry of Energy (2005, Table 4-5). We assumed the lowest-cost coal available, which was Powder River coal for Nanticoke and Lambton and Lignite for Thunder Bay and Atikokan. Since the report was based on 2004 dollars, we escalated to 2007 using the actual growth rate of bituminous and lignite prices from the U.S. Energy Information Administration (2008).

We computed the capacity-weighted average price and used a heat rate of 10,600 Btu/kWh to produce an average fuel cost of $28.08/MWh in 2007 dollars.

G. Nuclear

Performance

The RII model calculates generation from nuclear units based on OPA outage rates. The OPA provided projected forced outage rates for existing units in I-22-114 Table 3; projected planned outage rates for existing units in I-22-115 Table 3; and combined forced and planned outage rates for new nuclear units in I-22-114 Table 3.

We calculated nuclear unit availability as follows:

1. Forced and planned outage rates for new units were calculated by using the ratio of those outage rates for exiting units applied to the combined value for new units.
2. The availability in high load months (assumed to be all but April, May, October and November) was assumed to be:

   (1–forced outage rate)
3. The availability in the four remaining (low load) months was assumed to be:

   (1–forced outage rate) × (1–3 × planned outage rate)

These monthly availability factors were input to the dispatch module of the RII Model and the nuclear units were dispatched 100% of the time within the limits of those availability factors. The net capacity factors are hence equal to the availability factors as derived above.

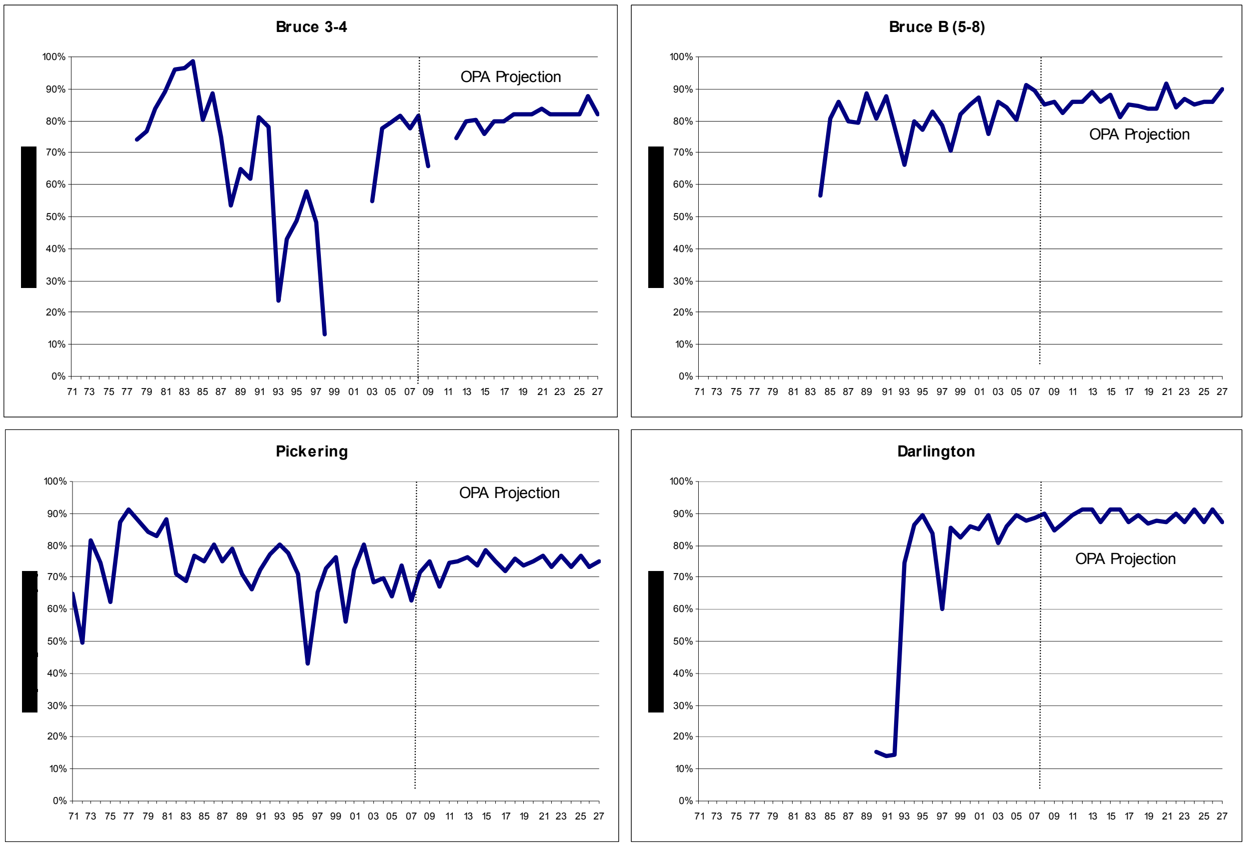
Capacity factors vary by month and year but average about 82% over the life of the plan.

Although we accept for modeling purposes OPA's outage-rate forecasts, we discuss below why such forecasts are not supported by operating experience in Ontario or elsewhere. We therefore assess the impact of OPA's optimism by modeling a sensitivity case that increases forced outage rates for all nuclear units by five percentage points.

Existing Units

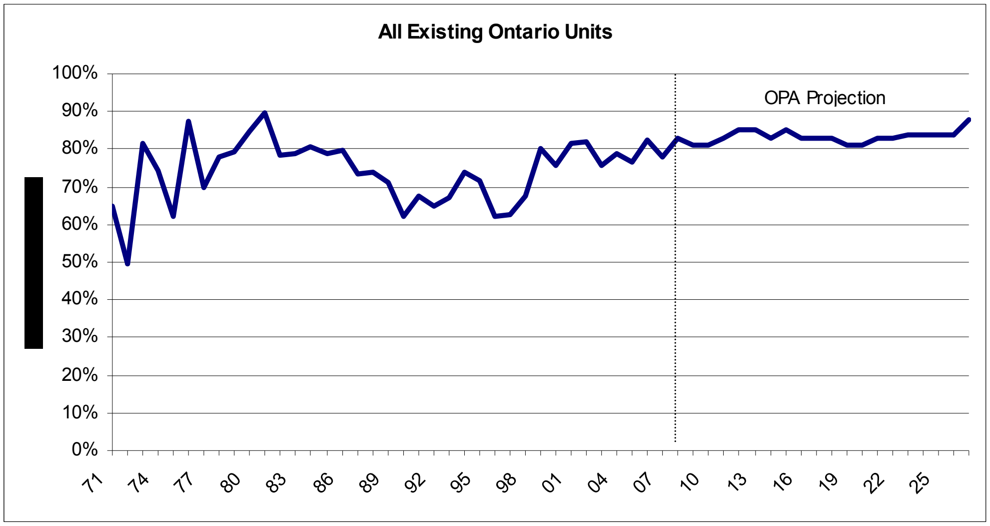
For existing units, OPA forecasts capacity factors based on the average of actual performance in 2005 and 2006 (Exhibit D-6-1, p. 31.) Forecasting performance based on experience in 2005 and 2006 amounts to an assumption that performance will continue for the next 20 years at the <u>best</u> levels of the past 20 years; see Figure 1.

Figure 1: Nuclear Performance



The OPA's optimism about future performance becomes more apparent in Figure 2, which rolls up all of the existing units into totals. Here we can see that the performance of the existing units is actually predicted to be at levels not seen in more than 25 years.

Figure 2: Ontario Nuclear Performance



The OPA's optimism is not supported by experience in other countries, where performance has improved substantially and then leveled off in recent years. Figure 3 illustrates worldwide performance. This shows a pattern of substantial improvement into the turn of the century followed by a leveling off at the higher values. Note that Figure 3 shows *unit* capability factor, which in all cases will be greater than the capacity factor.

The Ontario experience has lagged the worldwide data by about 6 points per year on average.

Figure 3: Nuclear Unit Capacity Factors, World Wide vs. Ontario

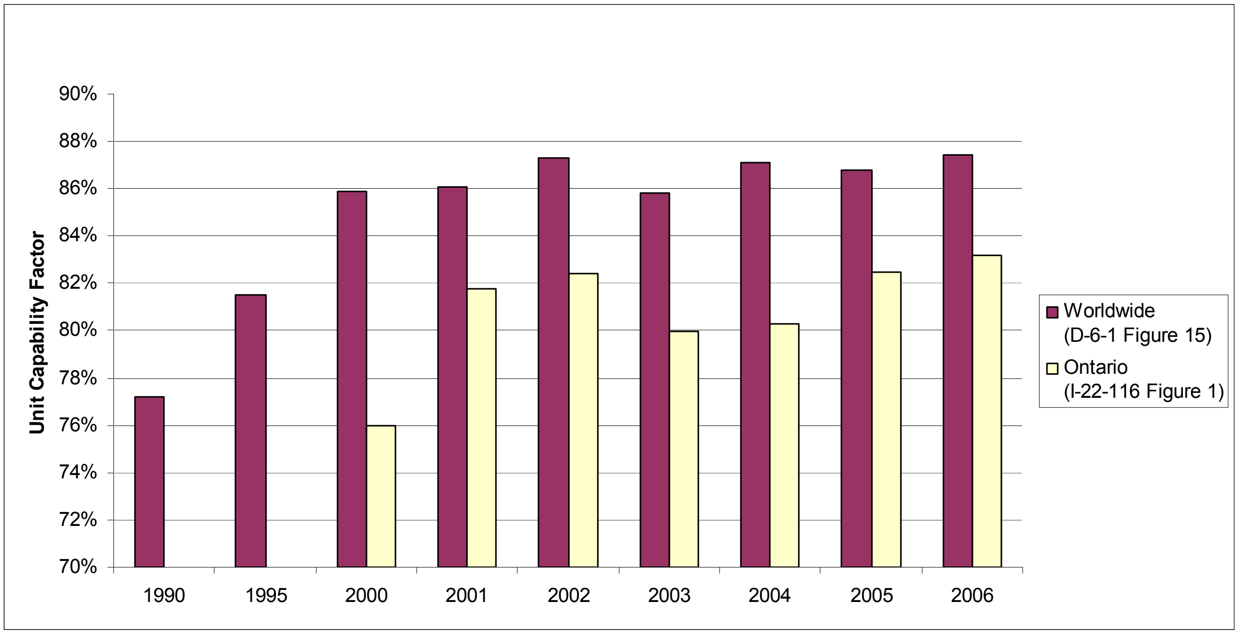
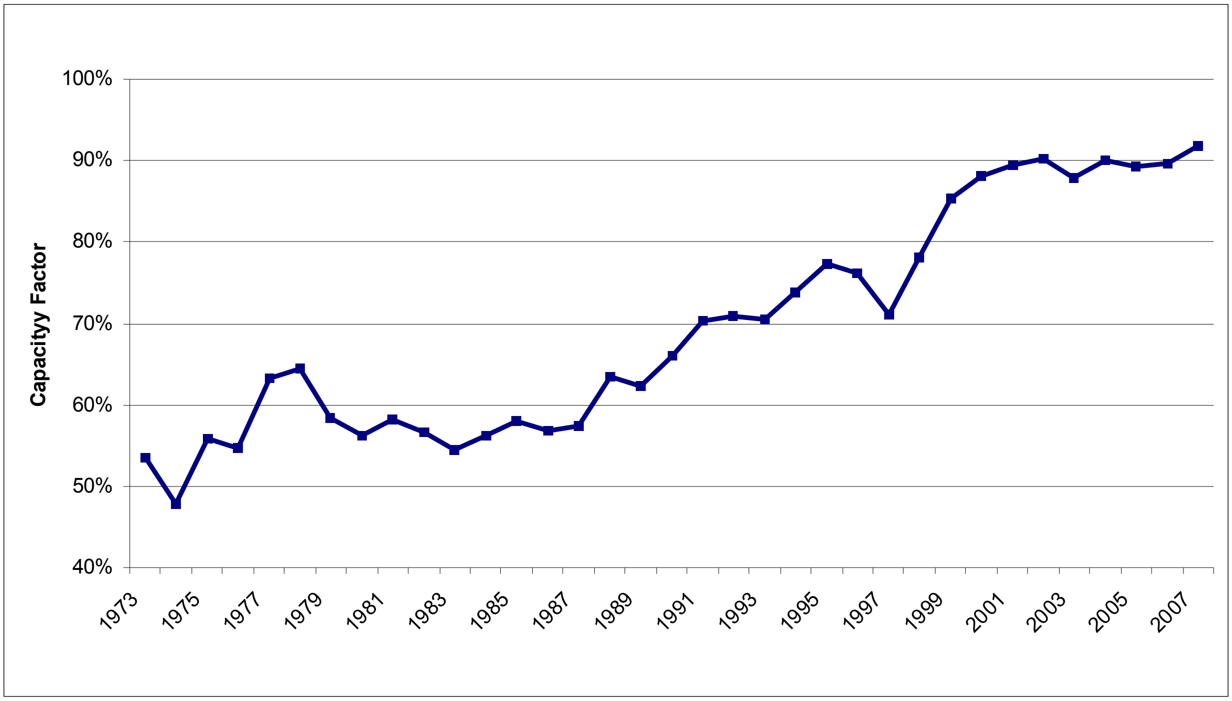


Figure 4 illustrates U.S. nuclear experience, which is not necessarily as healthy as it appears. First, the chart shows capacity factors—the corresponding capability factors would be even higher, indicating that the US results are well above the worldwide data. Second, note the same pattern of substantial improvement followed by a leveling off at the high values after the turn of the century.

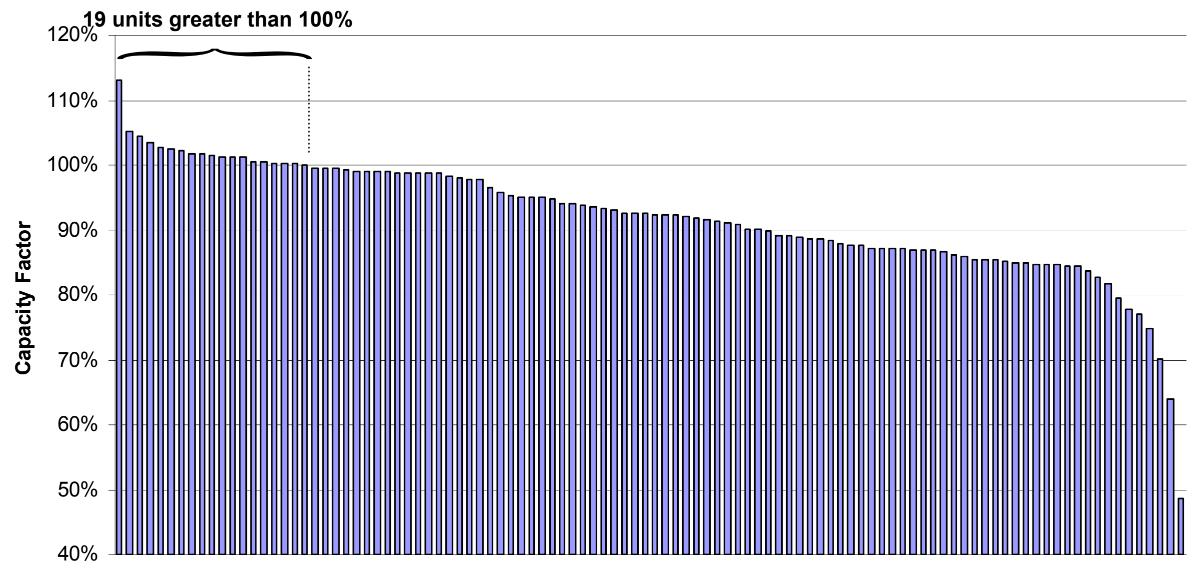
Figure 4: Average U.S. Capacity Factors



One might think the US experience is too good to be true. There is a basis for that concern. The 2007 average capacity factor, a remarkable 91.8%, is derived from a data base that includes 19 units with capacity factors greater than 100%, with the top value exceeding 113%. See Figure 5.

The underlying data understates capacity ratings for several plants. The top rated plant (Ginna) for example, is in the data base at 498 MW, while its true rating is actually 585 MW (Blake 2008, 29). The inevitable conclusion is that some not-insignificant part of the US improvement is based on capacity upgrades, not on better reliability or availability.

Figure 5: 2007 U.S. Capacity Factors



Source: U.S. Energy Information Agency

These data suggest that the high levels of performance may not be sustainable over the next ten to twenty years. Although there is no indication of any pending downturn, many plants in Canada and the US are reaching, or have already reached, the end of their originally intended lives. As more and more units age beyond original design intentions, we increasingly enter uncharted waters. One can reasonably expect a lower reliability and a heightened risk of major equipment failure, the kind that produces extended outages.

Will Ontario buck the worldwide leveling-off trend and begin a new wave of improvements? There is no reason to expect such an outcome. The historical data are consistent and Ontario remains steadily in the 80% range. There have been no signs of further improvement in the last seven years. Only 3 years of the last 35 have surpassed today's levels, and those were 25 years ago. More importantly, there is no basis to speculate that further improvements are forthcoming.

Planned Units

For planned units, OPA projects a uniform increase in capacity factor from 80% at start-up to 90% by 2027 (Exhibit I-22-113 Table 2.) OPA has therefore assumed that these units will begin life with capacity factors equal to the best historical performance of Ontario units (see Figures 1 and 2), and then improve in performance by ten percentage points. Such an outcome is highly unlikely given Ontario's prior experience.

The OPA has not provided any basis to support an assumption of 90% capacity factor for plants whose technology and design are still unknown. We asked OPA for any information that might indicate the impact of the proposed new technologies on capacity factors. The OPA declined to answer, claiming that such information is out-of-scope (Exhibit I-22-110.)

Capital Cost We adopt the overnight nuclear capital cost of $5,000/kW, from the evidence of J. Harding. We computed interest during construction (IDC) using OPA's assumed cash flow—six years of construction with equal expenditures in each year—and 4% real interest rate.

OM&A Using data provided by OPG in its rate filings for Darlington and Pickering, and data on Bruce costs from the annual reports of Bruce Power and its owners Cameco and TransCanada, we computed the following average OM&A costs for the nuclear stations:[20]

Table 4: Average Nuclear OM&A by Unit

	OM&A 2007$/kW-yr	Period
Bruce A	$300	2006–07
Bruce B	$170	2006–07
Darlington	$207	2005–07 actual, 2008–09 forecast
Pickering A	$446	2005–07 actual, 2008–09 forecast
Pickering B	$343	2005–07 actual, 2008–09 forecast

For the OPG plants, we allocated corporate overheads and any nuclear OM&A that was not assigned to a particular plant (other than expenditures on refurbishment, restart, and business development, which would include proposals for additional nuclear at Darlington) in proportion to station OM&A. The OPG average includes OPG's forecasts for 2008 and 2009 in EB-2007-0905 (Exhibit F2-3-1). These forecasts may be optimistic: in its 2004 Darlington Business Plan, OPG forecast that Darlington's OM&A in 2007 would be

[20]For Bruce, the table reflects data only for 2006 and 2007. Prior to 2006, Bruce Power and its owners reported only combined results. In late 2005, Cameco shed its ownership of Bruce A. So, starting in 2006, we can disaggregate the two stations.

$332 M and that non-assigned OM&A would be $143 M; the actual results were $405 M and $543 M.

We used fixed OM&A costs of $188/kW-yr for the new nuclear units, and variable OM&A for all nuclear units at OPA's assumed cost of $3.1/MWh (OPA Exhibit G-2-1 Table 1).

The OPA assumes OM&A costs for all nuclear stations of $108/kW-year in 2007 dollars. (Exhibit D-3-1, Attachment 1, Table 1)

Capital Additions

Using data from the same sources as for nuclear OM&A, we similarly determined historical capital additions for each nuclear station. Again, we excluded any costs attributed to restart, refurbishment, or new generation.

Table 5: Annual Capital Additions by Plant

	Additions *2007$/kW*
Bruce A	$34
Bruce B	$38
Darlington	$28
Pickering A	$19
Pickering B	$29

We assume capital additions of $31/kW-yr for planned nuclear units. The OPA assumes annual capital additions for all nuclear stations of $9/kW-year in 2007 dollars (Exhibit D-3-1, Attachment 1, Table 1).

Operating Lives

The OPA assumes that nuclear units have lives of 40 years, with a retubing after 30 years. These projected lives appear to be optimistic.

Of the twenty Ontario CANDU units, eight were shut down for protracted periods (at least 5.7 years) at ages of 18 to 26 years. Two of those units have been permanently retired, four refurbished, and two are in the refurbishment process. The operator of Pickering 1 and 4, OPG, hopes to get another 16 to 25 years from the restarted units. Ontario Power Generation also hopes its six other units will operate for 26 to 31 years. The OPA projects that the Bruce B units will operate for 30 to 32 years.

Based on this experience, we assume a 25-year operating life.[21]

H. Simple-Cycle and Combined-Cycle Gas Turbines

Capital

The IPSP assumes overnight capital costs of $665/kW for simple-cycle gas turbines and $924/kW for combined-cycle gas turbines, in 2007 Canadian dollars (Exhibit D-3-1, Attachment 1, Table 3). Interest during construction might add about 5% to those values (depending on the imputed interest rate) and stating the values in US dollars might reduce the values a few percent.

We reviewed press reports and regulatory filings for a large number of recent and planned SCGTs and CCGTs in Canada and the US, and found wide ranges of reported prices. The variation in prices is driven by differences in such factors as

- technology (among SCGTs, capital costs are lowest for frame units, higher for aeroderivative units, and highest for hybrid units);
- environmental requirements (e.g., in some locations, all new SCGTs and CCGTs must have selective catalytic reduction, while elsewhere only CCGTs are required to have SCR, and in some locations even CCGTs need not have SCR);[22]
- cooling-water availability for CCGTs, which may allow low-cost once-through cooling, more expensive wet cooling towers, or very expensive dry cooling;
- location, which influences the costs of land, construction labor and services, and other inputs;
- elevation;
- collocation with existing units, which may reduce or eliminate land, transmission and fuel-supply costs;

[21]The OPA projects that refurbishment will be approximately as expensive as new nuclear construction (Exhibit G-2-1, page 3), so neither they nor we need to distinguish between replacement or refurbishment.

[22]We have identified SCR on some, but not all, recent Ontario CCGTs.

- size and number of new units;
- arrangements for land, transmission and fuel supply, which may be capitalized or paid over the life of the project through leases or tariffs;
- accounting for transmission and fuel-supply costs, interest during construction, previously acquiring equipment and property, and shared costs;
- the reporting capacity (which may be stated for summer or winter conditions, among other conventions);
- timing of purchase of major equipment (because those costs recently spiked).

For SCGTs, we found total reported costs of $300–$650/kW for most locations, with prices up to over $1,000/kW for small plants in Connecticut, with high land and labor prices and required SCR. For CCGTs, we found total reported costs of $600–$1,200/kW for plants entering service in 2006–2008.

The OPA's capital-cost estimates fall in the range of costs we observed, although the SCGT cost estimate is at the high end of the range for units that do not require SCR. We selected all-in capital costs in 2007 Canadian dollars of $600/kW for SCGT and $1,000/kW for CCGT.

OM&A

The IPSP assumes fixed OM&A costs of $16/kW-year for SCGTs and $17/kW for CCGTs (Exhibit D-3-1, Attachment 1, Table 3). Based on our review of the OM&A costs of US and Canadian plants, OPA's estimate for the CCGT OM&A appears reasonable. Since we found many recent SCGTs that report total OM&A in the single digits, we used $10/kW-year for SCGTs.

We adopted OPA's estimates of variable OM&A, $2.75/MWh for CCGT and $3.50/MWh for SCGT.

Performance

We accepted OPA's estimates of a 5% forced-outage rate for all gas-fired generation, as well as OPA's heat rates of 7,000 for the combined-cycle units and 9,500 for the simple-cycle units. Actual heat rates for the SCGTs are likely to be somewhat higher, but they operate at such a low capacity factor that the heat-rate assumption is largely irrelevant.

Fuel

We forecasted fuel prices for gas-fired plants from futures prices at Parkway, Dawn and Henry Hub. As of June 23, the prices reported by NGX were as shown in the following table.[23]

Table 6: Henry Hub and Ontario Gas Prices as of June 23 2008

	Henry Hub	Dawn		Parkway		Price (2007 Canadian Dollars per MMBtu)				
	US$ per MMBtu	*US$ per MMBtu*	*Basis*	*US$ per MMBtu*	*Basis*	*Henry Hub*	*Dawn*	*Dawn Basis*	*Parkway*	*Parkway Basis*
2009	$12.32	$12.81	$0.49	$12.91	$0.59	$11.73	$12.19	$0.47	$12.29	$0.56
2010	$10.89	$11.55	$0.66	$11.64	$0.75	$10.11	$10.73	$0.61	$10.81	$0.70
2011	$10.49	$11.07	$0.58	$11.16	$0.67	$9.50	$10.03	$0.53	$10.11	$0.61
2012	$10.50	$11.04	$0.54	$11.10	$0.60	$9.28	$9.76	$0.48	$9.81	$0.53
Average								$0.52		$0.60

Assuming that the 2009–2012 average basis for each Ontario hub (in constant dollars) continues, recent forwards suggest the following delivered prices to Ontario:

Table 7: Anticipated Ontario Gas Prices

	Henry Hub $/MMBtu	Delivered price 2007$		
	Nominal	*2007$*	*Dawn*	*Parkway*
2013	$10.68	$9.21	$9.73	$9.81
2014	$10.90	$9.17	$9.69	$9.77
2015	$11.14	$9.14	$9.66	$9.74
2016	$11.38	$9.11	$9.63	$9.71
2017	$11.64	$9.09	$9.61	$9.69
2018	$11.90	$9.07	$9.59	$9.67
2019	$12.17	$9.05	$9.57	$9.65
2020	$12.44	$9.02	$9.54	$9.62

Rounding these values, and recognizing that some projects may have additional delivery costs from the Ontario hubs, we use $12.3/MMBtu in 2009, $10.8/MMBtu in 2010, $10.2/MMBtu in 2011, and $9.8/MMBtu thereafter.

[23] We assume for this computation that US and Canadian dollars are at parity.

I. Non-Utility Generation Contracts

The OPA treats separately a group of resources that it calls non-utility generation or NUGs. These are existing contracts between the Ontario Energy Financial Corporation and various owners of gas- and wood-fired generation, some of which is CHP. The OPA assumes that these are retired at the end of their contracts, and replaces them with new CCGTs. We accepted that assumption for modeling purposes.[24]

We accept OPA's estimates of the NUG capacity. We used the capacity-weighted average of OPA's separate estimates of heat rates for CHP and non-CHP NUGs.

The OPA treats these resources as being non-dispatchable, and apparently assumes that they operate at a constant 77% of installed capacity. Reviewing IESO data on hourly dispatch by station, we find that some NUGs operate primarily as baseload resources, while others reduce output overnight and shut down on weekends, and still others shut down entirely overnight. We thus modeled the NUGs plants as operating in proportion to hourly load, at 67% average capacity factor.

J. Combined Heat and Power

We adopt OPA's assumptions regarding the timing and capacity of existing, committed and planned CHP resources. We estimate annual non-fuel costs and performance for these additions based on OPA's assumptions regarding the costs and operating characteristics provided in Exhibit D-3-1, Attachment 2.

Our analysis of the hourly output of the existing CHP plants indicates that they roughly follow load. Typical generation patterns rise during weekdays, fall at night, and fall further on weekends. These patterns may follow some combination of steam load and electric load and prices. We modeled all existing CHP plants as operating in proportion to hourly load, which results in some generation at all times, with daily, weekly, and seasonal variations.

[24]These resources will probably be available at lower costs than new CCGTs, since they already exist and the owners are likely to want a contract to reduce market-price risks. In addition, some of the NUGs are fueled by wood waste, and some are CHP, both of which should provide lower energy costs than free-standing CCGT capacity.

We use the same fuel price for CHP as for other gas generation.

As discussed in the evidence of Thomas Casten, presented on behalf of GEC-Pembina-OSEA, there is likely to be significantly more cost-effective CHP potential than is included in the IPSP. In addition, Casten also discusses the magnitude of waste-heat recovery potential in Ontario, which would generate electricity without fuel cost. The generic clean resource additions in our cases could be composed in part of additional CHP and waste-heat recovery.

V. Finance Cost

We have priced out all new central generation and major CHP resources as if they will be financed by commercial developers, selling power to OPA at rates for capacity and/or energy that are fixed in real terms or indexed to fuel prices. This approach would transfer the risk of market prices away from the developer and essentially eliminate market-price risk for both the developer and consumers. We assume that all other risks (construction and operating costs, availability, efficiency) will be borne by the developer or subsequent owner.

The advantage of this approach is that it allows us to explicitly value the risks from the supplier side of various supply resources. It also produces reasonable estimates of the cost of competitive supply. The OPA's approach ignores the costs of financing resources, and risks are incorporated only to the extent that OPA explicitly models them.

The contract prices for resources could be reduced were OPA willing to assume the risks of cost overruns and poor performance. However, those guarantees would simply transfer the costs from the supplier to the customers, obscuring the costs without reducing them.

A. Cost of Debt

We assumed a 6% interest rate on debt for all resources. For higher-risk resources (i.e., nuclear), the increased risk is entirely reflected in the equity ratio and cost of equity.

B. Capital Structure and Cost of Equity

Transmission

We assume that transmission will be constructed primarily by Hydro One Networks, Inc. (HONI), using debt costing about 6%, or 4% in real terms. Our levelized costs for generation-enabling transmission are thus the same as OPA's.

Non-Nuclear Generation Resources

For new resources other than nuclear, we assume a capital structure of 50% debt at a 6% interest rate and 50% equity at a cost of 10.5%.

These estimates are based on the evidence of Kathleen McShane in EB-2007-0905, on behalf of OPG, and particularly the Exhibit L-12-2, in which Ms. McShane estimated that the capital structure for OPG's hydroelectric operations would be 45%–50% equity ratio, with a 10.5% cost of equity. They are confirmed by the capital structures bid to provide new gas-fired generation in Connecticut under cost-of-service contracts (Connecticut Department of Public Utility Control Docket No. 08-01-01). In Connecticut, bidders offered returns on equity from 9.75% to 10.75%, and equity ratios of 40% to 50%.

Nuclear Resources

Nuclear power plants face a range of risks, including higher construction costs, delay in completion and start-up, higher operating costs, large post-operation capital additions, low availability and short useful lives. See the evidence of Ms. McShane in EB-2007-0905 for a lengthy list of such risks borne by OPG for Pickering and Darlington, despite OPG's recovery of cost-of-service and various deferral mechanisms. As OPG explained, any generation is "subject to higher operating and production risks," and OPG's nuclear capacity is subject to additional risks:

> While there is some risk sharing of nuclear waste obligations with the government, the long run risk of nuclear liability remains a significant factor for OPG. OPG also faces significant levels of capital expenditure in the future for refurbishment and new plant development. These too will expose OPG to significant cost recovery risk in the future.
>
> OPG's dominant risk, however, is that the nuclear generating plants will not operate as planned. Nuclear technology is complex. OPG's fleet is an amalgamation of three generations of CANDU reactor, the newest of which, Darlington, was built more than 20 years ago and the oldest of which, Pickering A, was built over 40 years ago. As a result, OPG tends to be one of the first in the industry to encounter maintenance and reliability issues with the aging CANDU fleet. (OPG Argument in Chief, EB-2007-0905, pp. 7–8)

We looked to the following three sources for the cost of capital for nuclear non-utility generation operating under fixed-price contracts:

- Ms. McShane estimated that OPG's nuclear business, even with the support it receives from ratepayers, would have a cost of equity of 12.75% with a 45% equity mix, or 10.5% with approximately 65% equity.[25]
- In its review of the Bruce Power Refurbishment Implementation Agreement for the Ministry of Energy, CIBC World Markets found that a reasonable capital structure for Bruce Power's investment in Bruce A would be 60–80% equity, expecting to earn a 13.7%–18% after-tax equity return.[26]
- From its 2002–2007 Annual Reviews, Bruce Power appears to have been financed with 80%–90% equity, and to have earned an average of about 23% pre-tax return on equity over those six years. If its tax-paying owners pay 20%–30% taxes on their Bruce earnings, the after-tax equity return has averaged 16%–18%.[27]

While Bruce A bears more of the nuclear technology risks than OPG does for Darlington and Pickering, ratepayers share significantly in capital-cost overruns. Bruce Power also does not bear any costs of decommissioning or waste disposal. For a truly non-utility nuclear project, bearing all the risks of higher costs and lower output, we assume costs at the high end of the CIBC range: 80% equity and an 18% return.[28]

C. Taxes on Capital

Taxes affect the cost of OPA's procurements in two ways. First, taxes are a very real part of the costs determining the bids by generation developers for contracts with OPA under various RFPs, and the generation supplied under the RESOP. Second, the capital diverted to generation is diverted away from other

[25]An equity ratio of 67.5% would be required to equalize these two capital structures.

[26]Unsigned letter from CIBC World Markets to the Ontario Ministry of Energy (James Gillis, Deputy Minister and Rosalyn Lawrence, Director), October 17 2005.

[27]Since Bruce Power is a partnership, its tax liability is passed on to the partners.

[28]Neither OPG, Bruce Power nor a hypothetical future independent nuclear plant under contract to OPA would bear any risks related to the market price for power. The estimated cost of equity also does not include the costs of insurance for a nuclear accident, which are separately estimated in the evidence of G. Thompson.

investments, which must be expected to provide similar returns including taxes. Hence, the cost of generation investments to the economy include the after-tax profits that investors would otherwise have made with the capital, as well as the taxes paid by on those profits.

The Canadian Federal system for corporate taxes, combined with the Ontario corporate tax system, is quite complex, involving statutory tax rates, abatements, and reductions that vary by type of income, as well as accelerated depreciation schedules that vary widely by type of investment. In some cases, the tax depreciation schedule is determined in part by whether the corporation takes various tax-rate reductions.

Rather than building up an effective levelized income-tax rate from the tax rules, we examined the taxes paid by a sample of Canadian generation companies. Many pure generation companies (including Bruce Power) are partnerships or trusts, which pass their earnings to their owners, who actually pay the taxes. We identified three companies that publicly report taxes on earnings primarily from Canadian power generation: Canadian Hydro Developers, TransAlta, and TransCanada. While TransCanada's income is predominantly from its pipeline operations, TransCanada reports results separately for its energy operations, which are dominated by generation, most of it in Alberta and Ontario (including partial ownership of Bruce Power). The following table shows the ratio of current taxes to net income for each company for each year, 2005–2007.[29]

[29] In 2005, Canadian Hydro Developers reported taxes that were 53% of earnings before taxes, but earnings were reduced by "Unwind costs on interest rate swap." We could not determine the effect of those unwind costs on taxes, so we removed them. Canadian Hydro's low tax rate for 2006 may have resulted in part from tax benefits of those costs.

Table 8: Taxes as Percent of Net Income

	Energy Tax Rate			
	2005	2006	2007	Average
Canadian Hydro Developers	30%	8%	26%	22%
TransAlta	16%	47%	16%	26%
TransCanada Energy Segment	23%	28%	27%	26%
Average				25%

We assume an income tax rate of 25% for all planned generation.

VI. Case Development and Evaluation

Our analysis is designed to develop resource plans that economically and prudently satisfy the reliability and energy requirements of Ontario, while complying with government directives and regulations. The direction from the Government includes the following mandates:

- All coal plants must be shut by the end of 2014.
- Coal plants are to be replaced by cleaner sources as soon as practical.
- From 2011 on, coal consumption cannot emit more than 11.5 megatonnes of carbon dioxide annually, which limits generation to about 11 TWh annually.
- Nuclear capacity is limited to 14,000 MW.
- The IPSP must include at least 1,350 MW of CDM from 2008 through 2010 and at least another 3,600 MW of CDM from 2011 through 2025.
- At least 2,700 MW of renewables must be installed in 2004–2010, and total installed renewable capacity must be at least 15,700 MW by 2025.

We demonstrate that aggressive CDM, especially energy efficiency, combined with increased development of renewables and other clean energy sources, meet the policy requirements at a substantially lower cost than the IPSP. Our supply cases also have important non-monetary benefits.

A. Analytical Approach

Resource Portfolios

In building resource-portfolio cases, we start with OPA's energy and demand forecasts. From those forecasts, we subtract the effects of sustained innovative CDM efforts, as estimated in the evidence of Scudder Parker. We then compare the residual peak load to the load-carrying capability of existing, committed, and planned CHP and non-wind renewables, and schedule in wind and gas to make up the difference. Specifically, we add on-shore wind on the same schedule as OPA's planed wind, but in larger quantity, and add off-shore wind starting in 2018. We fill the remaining requirement with a combination of intermediate and peaking clean resources, which we model as SCGT and CCGT technologies, respectively.[30]

We then look to the energy modeling to determine the mix of clean resources, based on hours of use, and to ensure that the energy supplies could meet energy requirements without imports. We also use the energy model to determine the frequency and magnitude of surplus baseload generation in excess of the 1,000-MW limit that IESO (2008) considers prudent for planning purposes.

We assume no imports or exports for capacity planning purposes. Unlike OPA, we did not allow the model to schedule generation for economic export; in our approach, energy is generated in excess of Ontario load only when required by minimum generation levels. We conservatively assume that energy is dumped in the market and thus take no credit for the sale of that energy.

In reality, even with the expansion plans in our cases, individual market participants and the IESO may choose to import and export energy. Economic imports will reduce costs, and economic exports will increase Ontario profits (in some cases, reducing the costs borne by Ontario consumers.) We do not include these effects in our runs.

Portfolio Cost and Performance

We use our spreadsheet model to estimate annual fixed and variable costs of resources over the period 2008–2027. We model variable costs for all

[30]The SCGT and CCGT are proxies for various clean resources, including additional CHP, waste energy, renewables and storage.

resources, fixed OM&A costs for existing coal, and both fixed OM&A and annual carrying costs on capital for planned resources.[31]

We discount these annual costs to 2007, using OPA's estimate of the real social discount rate of 4%. As a sensitivity, we also used a real social discount rate of 8%.

Effective Load-Carrying Capability

The amount of generation capacity required to serve load at a target reliability level (such as the 0.1 day per year loss-of-energy expectation target in Exhibit D-2-1, Attachment 1) depends on the performance of the generation, including its forced outage rate, its maintenance requirements (to the extent those impinge on reliability), other limits on generation output, the size of units and the correlation of outages among units. For hydro and wind resources, OPA takes into account the resource-related output limits, derating hydro to 77% of installed capacity based on median output at peak and derating on-shore wind to 20% of installed capacity based on average generation at peak. OPA treats all other generation resources as serving equal amounts of load, regardless of outage rate or unit size.

However, when the IESO computes required reserve margins for various years in Exhibit D-2-1, Attachment 1, it finds that those margins vary due to the differences in the generation mix and thermal-plant forced-outage rates that OPA specified for the analysis years (2010, 2016, 2020, and 2026). Specifically, the IESO notes that reliability requires less total capacity when there is more gas capacity and less coal and nuclear capacity, due to the latter's higher outage rates (Exhibit D-2-1, Attachment 1, p. 9). Yet, OPA treats the annual reserve requirements to be fixed, unaffected by different supply mixes in various cases.

Simply put, for a given load, providing reliable service requires more megawatts of large high-outage-rate nuclear units than of smaller gas units with low outage rates. To reflect this phenomenon, our analysis recognizes the different load-carrying capability of an installed MW of each category of generation resource.

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[31]For planned wind and hydro resources, we include carrying charges on enabling transmission as a component of fixed OM&A.

The amount of incremental load that a given generator can support on a given system is called the Effective Load-Carrying Capability, or ELCC.[32] Garver (1966) modeled ELCC as

$$\text{ELCC} = c - m \times \ln(1 - r + r \times e^{c/m})$$

where c = the capacity of the unit

m = a constant specific to the generating system, reflecting the load shape, and the number, size and outage rates of other units

r = the unit's forced outage rate

ln = the natural logarithm

e = the base of the natural logarithm

We estimated the constant *m* from the IESO results in Exhibit D-2-1, Attachment 1, specifically the findings regarding the additional reserves required when nuclear forced outage rates (FORs) are increased from base-case levels.[33] We made the following assumptions:

- The IESO applied the same FOR to each nuclear unit, even though OPA assumes a wide range of FORs for the various units.
- The ISO added 300-MW gas-fired plants with 5% forced outage rates to maintain reliability with the higher nuclear FOR. To determine the capacity required to meet its reliability target for the base-case nuclear FOR, the IESO reduced the planned (or even existing and committed) gas capacity until the reliability target was just met, leaving 17% to 31% of available gas capacity unutilized.[34]

We then determined the value of *m* that would result in a reduction of nuclear ELCC due to the higher FOR that is equal to the increase in ELCC from the additional gas capacity IESO found necessary. For the various years, the resulting value of *m* ranged from 450 to 630 MW. For estimating the ELCCs of

[32]The OPA defines ELCC differently, as equivalent capacity-replacing capability, rather than load-carrying capability (Exhibit I-1-12, footnote 43). We use the standard definition.

[33]The OPA asked IESO to model FORs in the base case of 3.8% to 5.5% in various years, with 50% higher FORs in the sensitivity case. The point of this exercise is not clear, since OPA projects much higher FORs for the nuclear fleet, averaging 10.8%.

[34]In 2010, the IESO also removed about 2,000 MW of coal.

various units, we used 600 MW; lower values would further reduce the ELCC of large units (Pelland and Abboud 2007).

Our estimates of ELCC for each type of thermal unit are summarized below:

Table 9: Estimated ELCC by Unit

	MW	OPA-estimated FOR	ELCC per MW Range	ELCC per MW Average
Nanticoke	478	12.8%	82%	
Atikokan & Thunder Bay	150–200	12.8%	85%–86%	85%
Lennox	575	11%	84%	
Gas and Biomass	<100	5%	95%	
Gas	>500	5%	92%–94%	94%
Darlington	881	3.8–5.5%	89%–92%	90%
Bruce B	795	6.9–9.3%	83%–87%	84.5%
Bruce A	750 or 770	12–13.2%	77%–79%	78%
Pickering B	516	18.8–19.9%	72%–73%	73%
Pickering A	529	16.2–17%	76%–77%	76%

The nuclear FORs are from Exhibit I-22-114, Attachment 3; unit averages excluding zeros. Other FORs are from Exhibit D-2-1, Attachment 1. Some nuclear maintenance appears to be performed at high-load times, such as the Pickering-A outage in the summer of 2007. The FORs that OPA reports for 2007 average to 8.5%, but the IESO's report of nuclear capability in the 200 highest-load hours of the summer average more than 15% below the plants' rated capacity, and output in those hours average 17% below their rating. Hence, the effective reliability of the nuclear units is almost certainly lower than OPA has reported.

In addition, outages for the nuclear units are not independent. That was true for the simultaneous and related summer-2007 outage of Pickering 1 and 4, and more broadly as well. The average correlations among the annual FORs of the units in a station (e.g., Darlington, Pickering B, or Bruce B) has been about 0.30, indicating that outages at one unit tend to correlate with outages at another unit at the station . In Exhibit I-22-221(c), OPA makes this point for forced outages, ignoring outages OPA classified as maintenance. The average number of Ontario nuclear units in service in 1972–2007 was about 11; Exhibit I-22-221(c) shows 3 or more units on forced outage simultaneously almost half of the time.

The new nuclear units that have been proposed for Ontario range from 1,000 MW to 1,600 MW. These larger units would have lower ELCC ratios than the existing nuclear units, for the same forced outage rate. With a 5% FOR, for example, the ELLC ratio would be 89% at Darlington's 881 MW rating, 88% at 1,000 MW, and 81% at 1,600 MW.

The OPA derates hydro capacity to the median level of on-peak generation. For example, in Exhibit D-2-1 Attachment 1, IESO describes the hydro capacity as being "set at 10-year historical average of the energy contributions of hydro at the time of system peaks, plus a contribution to operating reserve." We assume that the derated hydro capacity is essentially the same as ELCC.

Similarly, OPA derates wind, to 20% of its nameplate capacity for on-shore wind and 25.3% of nameplate capacity for off-shore wind, to reflect average amounts of wind energy available at peak hours. OPA refers to this derated capacity as "effective capacity." In Exhibit D-2-1 Attachment 1, the IESO reports that it modeled additional variability in wind output, but does not provide any results indicating whether that variability increases or decreases the amount of capacity required to maintain target reliability. We assume that the effective wind capacity is equivalent to ELCC.

By its very nature, ELCC is a marginal concept, estimating the reliability contribution of an additional unit or units. For a given unit size, the ELCC rises as the system grows and more units are added. Summing our estimates of ELCC over the 29,410 MW of generation resources in the IESO computation for 2010, we get an ELCC of 26,563, while the IESO only credits that amount of capacity with supporting 24,811 MW of load.[35] Hence, we subtract 1,750 MW from the total system ELCC to reflect the diseconomies of reaching the current system scale.

B. The RII Model

The RII model is a multi-spreadsheet-based simulator designed to facilitate analysis of system planning options. We relied on the model to develop and to

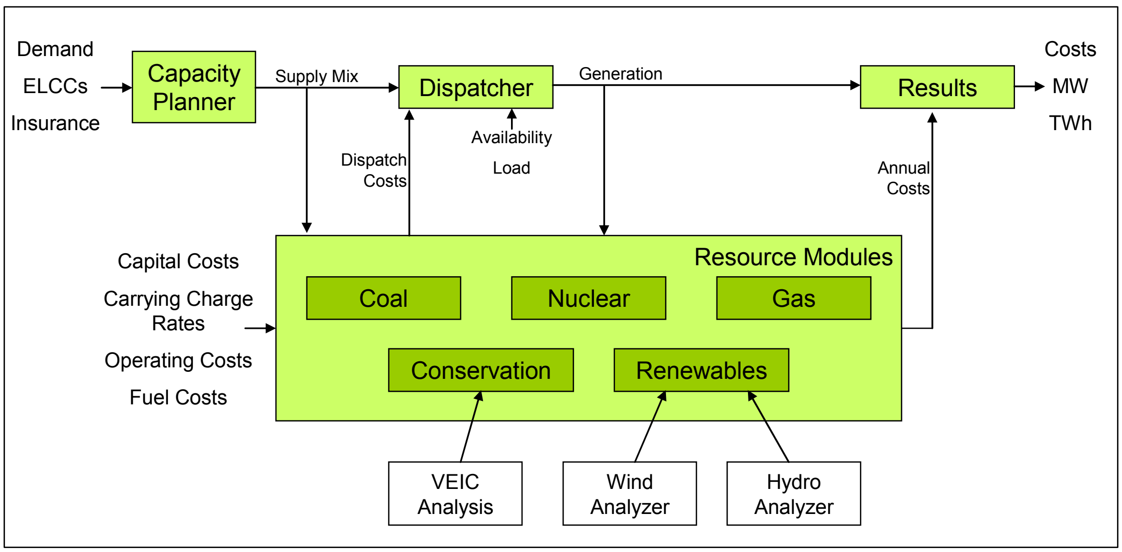
[35]The load and resources are from Exhibit D-2-1, Tables 5 and 6, with conservation treated as a reduction in load rather than a resource.

forecast the costs and performance of resource portfolios that serve Ontario load reliably and cost effectively.

As an integrated package, the model incorporates all critical system planning considerations, including system reliability (reserve) requirements; individual costs and operating characteristics for resource types; dispatch of resources economically or as directed by operating limitations; and analysis of costs and output.

The simplified flow of the model is shown in Figure 6. The model comprises three primary "engines:"

Figure 6: The RII Model



The Capacity Planner begins with an inventory of proposed supply resources, including installed MW for each year of the plan. It calculates an Effective Load Carrying Capability (ELCC) for each resource. The demand requirement is calculated by specifying peak demand and adjusting it upward for added reserve requirements (insurance reserve) and downward for CDM. Resources are then adjusted by the analyst to produce a reasonable balance of supply and demand for each year of the plan. This design is an iterative process as the practicality of the supply mix (such as the relative proportion of base, intermediate and peaking resources) must then be proven through simulated operation in the Dispatcher.

The Dispatcher simulates operation of the total system on an hourly basis for the entire 20 years of the plan, or approximately 175,000 hours. For each hour, we calculate load based on OPA forecasts of peak demand and a typical load-duration curve for the system. The latter produces a load factor of about 67%. Hourly load is reduced for CDM and increased as appropriate to eliminate any SBG condition.

As a result, the generation provided via the Dispatcher is as follows:

Generation = OPA forecasted load–conservation + SBG exports

For dispatch purposes, the model assumes that there is no limit to the amount of SBG exports that can be accommodated. But the Dispatcher also calculates the number of potential SBG events and their severity. For those calculations, the model assumes that a maximum of 1,000 MW of exports is available. Accordingly, the number of SBG hours and the average and peak excesses are *after the first 1,000 MW*. Typical SBG output from the Dispatcher is illustrated in Table 10.

Table 10: Typical SBG Outputs from the Dispatcher

	SBG Exports (GWh)	SBG Hours	SBG Avg. MW	SBG Max MW
2008	0.388	138	428	1,102
2009	0.496	192	428	1,200
2010	0.936	418	548	1,662
2011	1.381	601	652	1,980
2012	3.781	1,626	836	2,874
2013	7.403	3,136	1,111	3,630
2014	9.495	3,759	1,301	4,118
2015	5.876	2,647	906	3,102
2016	2.087	837	586	1,976
2017	1.160	412	424	1,372
2018	0.225	34	173	650
2019	0.092	11	235	499
2020	0.112	22	207	615
2021	0.027	2	47	76
2022	0.011	0	0	0
2023	0.005	0	0	0
2024	0.002	0	0	0
2025	0.000	0	0	0
2026	0.000	0	0	0
2027	0.000	0	0	0

As discussed elsewhere, the SBG issue is an outgrowth of the relatively large amounts of baseload capacity in the IPSP. The impact is masked if one simply assumes unlimited exports. Hence, an important feature of the model is its ability to provide visibility to this important parameter.

The output of the Dispatcher is the annual generation for each type of resource, and hence its capacity factor.

The Dispatcher treats each resource type differently in determining its place in the resource stack, and our assumptions generally track the assumptions and requirements of OPA and the IESO. This produces a typical stack as shown in Table 11.

Table 11: Typical Dispatch Scheme

Dispatch Order	Resource	Basis for Dispatch
1	Solar	Forced to 12% capacity factor
	Wind	Forced to capacity factors defined in the wind analyzer (28%-32%)
	Hydro (run of river)	Forced to 100% CF
	NUGs	Forced to system load factor (about 67%)
	CHP	Forced to system load factor (about 67%)
	Nuclear	Always run full within OPA assumed outage rates
7	Hydro (storage)	Run at 36% CF after first 12,000 MW is dispatched
8	Bio	Economic dispatch within OPA assumed outage rates
9	Coal	Economic dispatch within OPA assumed outage rates
10	CCGT	Economic dispatch within OPA assumed outage rates
11	SCGT	Economic dispatch within OPA assumed outage rates
12	Imports	Last resort

All of the units with dispatch order 1 run 100% of the time (derated for assumed capacity factor), illustrating the potential problem if those units lack operational flexibility and make up too much of the system.[36]

The model manages the cost and performance details of each resource type in the Resource Modules. These modules contain the key cost information for each resource, including installation costs, capital additions, and per-unit fuel costs and fixed and variable OM&A. The modules receive the amount of the resource (MW) from the Capacity Planner and the output of each resource (GWh) from the Dispatcher. This enables each module to calculate annual costs.

As in the IPSP, the modules are structured by existing, committed, and planned resources. Fixed costs (capital and fixed OM&A) are not calculated for existing and committed resources as such costs are sunk or do not vary between cases. An exception here is the fixed OM&A costs for coal, since the retirement dates for those units are in play and will impact the cost picture. All costs associated with planned resources are included.

In three cases, the resource characteristics were considered suitably complex to justify a supporting analysis. In the case of CDM, a detailed analysis of various scenarios was prepared by VEIC (evidence of Scudder Parker) and recommendations for possible MW and TWh savings and costs to obtain those savings presented. VEIC's data feed directly into the conservation module.

The creation of a hydro or wind portfolio has a number of variables that are a function of the specific site and size of the potential units. To accommodate the analysis required to produce these portfolios, analyzers were built for both hydro and wind that feed directly into the renewables module.

The final outputs of the model are collected in a results spreadsheet. It consists of three data bases, one each for capacity (MW), output (TWh) and cost (2007

[36]Some of the technologies in the first dispatch group create more opertational problems than others. For example, solar will tend to align with summer peak and will not exacerbate SBG during overnight minimum-load hours.

dollars). This data is provided for each year and for each resource broken down by specific type of generation and year. A breakdown of existing, committed and planned is also included.

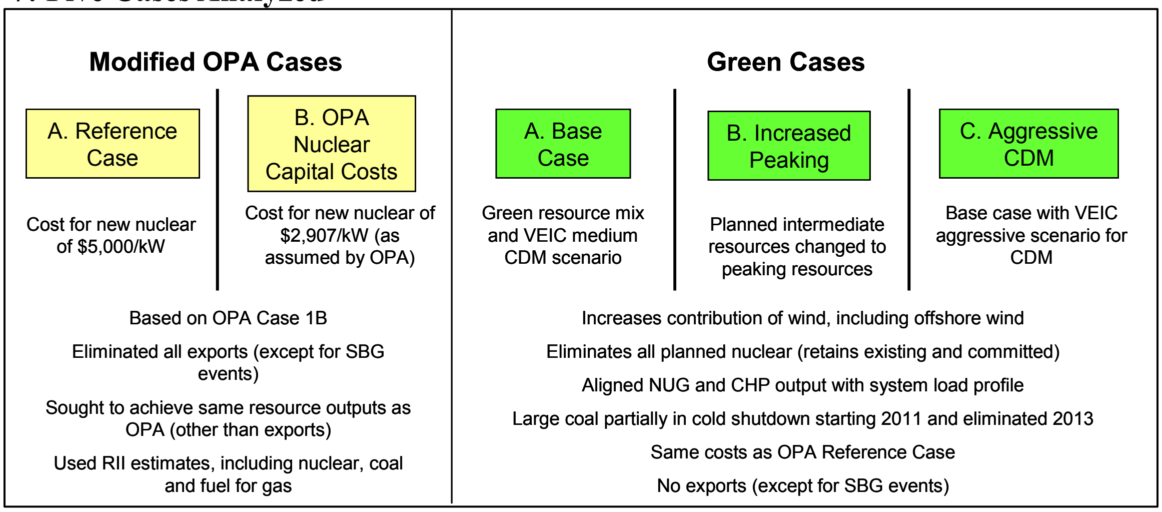
The output sheets also provide summary data for all parameters and also summarize the capital requirements for the scenario by resource type.

VII. Case Results

As discussed in the previous section, we simulated the costs and performance of a number of resource portfolios through the RII model. The first step in this modeling exercise was development of a benchmark set of inputs for the purposes of calibrating the RII model to the dispatch results for the resource portfolio in OPA's Case 1B of the IPSP. In essence, this step involved replicating OPA's input assumptions regarding customer load, CDM, generating plant capacity, operating costs, operating characteristics, and annual exports to ensure that the RII model simulated plant dispatch consistent with that reported by OPA for Case 1B.

Once calibration was completed, we constructed and modeled five cases that incorporate a variety of modifications to OPA's assumptions for Case 1B regarding the magnitude of CDM savings; the type, magnitude, costs, and operating characteristics of planned additions; the dispatch and retirement schedule for existing coal; and the treatment of exports. We developed two "Modified OPA" cases that modify various assumptions regarding fixed costs and input fuel prices, but otherwise retain the Case 1B assumptions regarding capacity additions and generating-resource operating characteristics. The three "Green" cases incorporate the input revisions of the Modified OPA cases, as well as changes to the Case 1B assumptions regarding plant operating characteristics and the dispatch and retirement schedule for existing coal capacity. Most importantly, the Green cases incorporate fundamental changes to the Case 1B supply plan, eliminating all planned nuclear additions in favor of a mix of enhanced CDM savings, additional on-shore and off-shore wind capacity, and other clean resources.[37]

Figure 7: Five Cases Analyzed



Substituting a mix of CDM, wind, and clean resources for planned nuclear capacity dramatically lowers the cost to reliably serve Ontario load. Relative to the OPA Reference Case, the Green Base Case provides net-present-value savings of about $21 billion, or about 24%, at a 4% real social discount rate (and about $11 billion at an 8% social discount rate). Even when using OPA's unrealistic estimate for nuclear construction cost, eliminating capital-intensive nuclear investments from the resource portfolio reduces costs over the 20-year planning horizon by $8 billion, or about 11%. See Figure 8. Actual savings may be even greater than we estimate, given the high risk of nuclear construction cost overruns in the Modified OPA cases.

[37]As discussed above, we model these other clean resources as a combination of planned CCGT and SCGT.

Figure 8: Net Present Value of Annual Costs by Case (Billions of Canadian Dollars)

	Modified OPA Cases		Green Cases		
	A. Reference Case	B. OPA Nuclear Capital Costs	A. Base Case	B. Increased Peaking	C. Aggressive CDM
At 4% DR	87.7	74.7	66.4	66.1	65.7
At 8% DR	55.2	48.1	44.5	44.4	44.4

These costs savings do not come at the expense of reduced capacity adequacy or operational flexibility. The Green cases maintain annual planning-reserve margins that are, on average, only slightly less than the generous values adopted by OPA to meet NPCC reserve requirements and to provide additional insurance reserves. Moreover, the Green cases improve dispatch flexibility by replacing inflexible nuclear capacity with a combination of load-following CDM, baseload wind, and dispatchable clean resources.

Details of each case, and their relative attributes, are discussed below. In the Appendix to this evidence we provide six tables for each case showing annual data for each of the following model outputs:

1. Installed capacity in MW.
2. Effective capacity in MW.
3. Supply requirements in MW and percent reserve.
4. Generation in TWh.
5. Unit capacity factors.
6. Annual costs in millions of dollars.

These detailed results are summarized in the discussion below.

A. OPA Reference Case

The OPA Reference Case mimics OPA's Case 1B, which is characterized by no refurbishment of Pickering B.[38] Total installed capacity rises from about 32,000 MW in 2008 to 40,000 MW in 2027.

[38]As elaborated in the final argument of AMPCO in the current OPG Prescribed Generation Payments case, Pickering A operating costs are extremely high despite considerable refurbishment. This supports an

The OPA Reference Case differs from Case 1B in the following respects:

- Nuclear overnight construction costs increased from $2,907/kW (2007$) to $5,000/kW, per the evidence of Jim Harding.
- Increased nuclear fixed OM&A and capital additions to $188/kW-year and $31/kW-year, respectively.
- Updated fuel-price forecast for natural gas.
- No allowance for economic exports.

Table 12: Changes in Capacity Entailed in OPA's Case 1B

Resource	Change in Installed Capacity (2008–2027)
Nuclear	1,806
Wind	4,026
Hydro	2,936
Other renewables	509
CHP	969
NUG	–1,373
CCGT	5,940
SCGT / Lennox	–175
Coal	–6,434
Total	8,204

Case 1B would entail substantial net additions of hydro, wind, and gas-fired generation over the 20-year planning horizon. See Table 12.

The effective capacity, i.e., that which can be counted on to contribute at times of peak demand, is the same for each resource type except for hydro and wind. Those resources are reduced to 77% and 20% respectively in accordance with OPA estimates. Effective capacities are detailed in Table OPA-A-2 in the Appendix.

The OPA Reference Case produces substantial effective reserves. Effective reserve margins exceed 40% in 2013 and 2014, as OPA argues that coal units are needed for "insurance". As shown in Table OPA-A-3, reserves are generally high for the life of the plan, exceeding 30% in the early years and running in the mid to high 20s in the later years.

Comparison of the simulated dispatch of existing coal capacity in the OPA Reference Case against that of the benchmark simulation of Case 1B indicates the extent to which coal is being dispatched for export in the latter case. The OPA Reference Case assumes no economic exports. Case 1B, in contrast, includes annual exports, on average, of about 23 TWh between 2010 and 2014,

assumption that Pickering B will not be refurbished. Further, OPA assumes that refurbishment costs will equal costs for new construction, which our analysis finds to be uneconomic.

Coal output would grow about 10 TWh per year on average to serve economic exports in our benchmark simulation of Case 1B; see Table 13.

Table 13: Annual Coal Generation (TWh)

	2010	2011	2012	2013	2014
Case 1B Benchmark Simulation	26	21	15	15	13
OPA Reference Case	14	10	6	3	3
Coal Generation for Export	12	11	9	10	10

The unit output data also reveal that the long-term supply mix offers little in the way of diversity of energy supply. Nuclear and hydro provide 86% of the energy in 2022, while wind provides less than 10%. The latter statistic reveals a material under-utilization of a high-potential resource. See Table 14.

Table 14: Resource Share in 2022 for OPA Reference Case

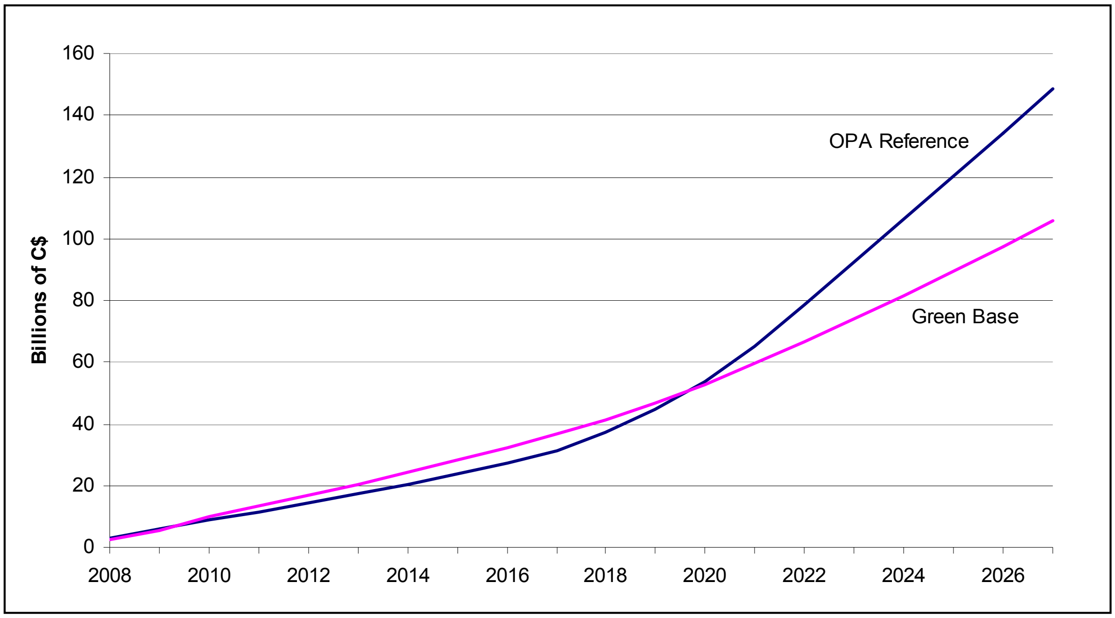
	Contribution to Ontario's Energy Needs in 2022
Nuclear	57.8%
Wind	7.2%
Hydro	28.1%
Other renewables	0.9%
CHP	3.0%
NUG	0.6%
CCGT	2.4%
SCGT / Lennox	0.0%
Coal	0.0%
Total	100%

Unit capacity factors are detailed in Table OPA-A-5. Since we assumed no exports, the capacity factors tend to be lower than OPA's assumptions for dispatchable resources and identical for the non-dispatchable resources. Our low values for gas-fired generation (except for the immediate years after coal's retirement) again illustrate the over-optimistic contribution of OPA's export assumptions. In reality, the gas-fired resources are likely to be under-utilized in OPA's plan.

The most telling attribute of the OPA Reference Case is cost, as detailed in Table OPA-A-6. With a net present value of nearly $88 billion over the plan period, this case illustrates the likely economic harm from commitment to a nuclear-centric planning approach.

Figure 9 illustrates the wide divergence in costs between the OPA Reference Case and the Green Base Case. Since we treat fixed costs for existing and committed nuclear units as sunk, the OPA option actually appears slightly cheaper in the early years. But when new nuclear arrives, the story changes dramatically, with the costs of the OPA case rising quickly above that for the Green case. By 2027, that gap is about $6 billion per year. In the OPA Reference Case, annual costs in 2027 amount to more than $14 billion per year.

Figure 9: Comparison of Cumulative Costs, OPA Reference Case vs. Green Base Case



As discussed in Section IV, we adopt OPA's optimistic assumptions for nuclear performance, but test the sensitivity of model results against more realistic assumptions. Specifically, we model the OPA Reference Case assuming an increase in nuclear forced outage rates of five percentage points.

The resulting nuclear capacity factor drops by 5% from OPA's Reference Case and annual nuclear output declines by about 5 TWh per year. This drop in output has a significant negative impact on comparative nuclear economics, further weakening nuclear's competitive position versus other technologies. In addition, higher outage rates increase the cost of the OPA Reference Case by about $1.9 billion on a net-present-value basis.

In addition to the negative economic effects, almost 70% of the lost nuclear generation is made up by an increase in coal-fired generation.. This effect highlights the extent to which the IPSP relies on dirty coal generation to compensate for poor nuclear performance.

Table 15: Nuclear Forced-Outage-Rate Sensitivity Case versus OPA Reference Case

	OPA Reference Case	Nuclear Forced Outage-Rate Sensitivity Case
NPV of Annual Costs ($B)	87.7	89.6
Nuclear Capacity Factors (%)	78.4–82.6	73.4–77.6
Nuclear Generation—2010 (TWh)	78.4	73.4
Coal-Fired Generation—2010 (TWh)	13.8	17.2

B. OPA Nuclear Capital Cost Case

This case is identical to the OPA Reference Case, except for the value assumed for nuclear overnight construction costs. Whereas the OPA Reference Case assumes an overnight cost of $5,000/kW (without interest during construction), this case adopts OPA's assumption of $2,907/kW. While not considered realistic, we model this case to test the sensitivity of bottom-line results against assumptions for nuclear capital costs.

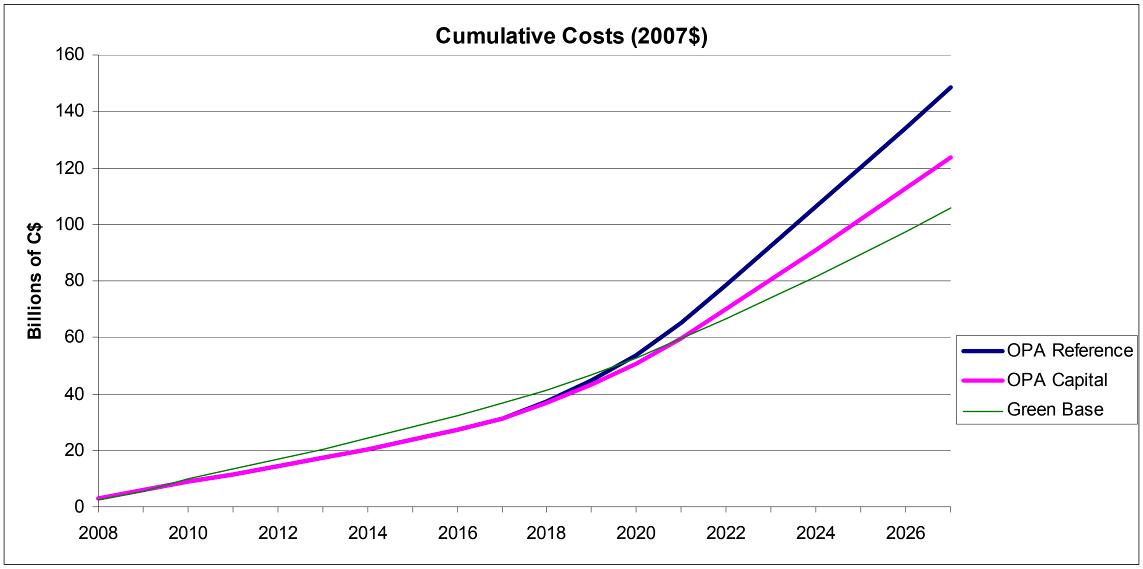
Details of this case are included in Tables OPA-B-1 through 6. However, note that all results except for annual costs are identical to those for the OPA Reference Case. Table 16 highlights the significant impact that nuclear capital costs have on total costs. In this case, a 72% increase in capital costs for just the planned nuclear units increases 2027 annual cost for the *entire system* by 30%.

Table 16: Impact of Nuclear Capital Cost Assumptions

	Nuclear Construction Cost ($/kW)	Total 2027 Cost ($B)
OPA Nuclear Capital Cost Case	$2,907	$11.1
OPA Reference Case	$5,000	$14.4
Increase	72%	30%

Despite the significant improvement to the OPA case from this unrealistic assumption for nuclear capital cost, the Green Base Case still proves to be far less costly, as is illustrated in Figure 10. Note that the slopes of these lines continue for many years, making the OPA nuclear options increasingly cost ineffective and imprudent. The net present value through 2027 of the difference in total costs between the OPA Nuclear Capital Cost Case and Green Base Case is about $8 billion.

Figure 10: Cumulative Costs of Three Cases



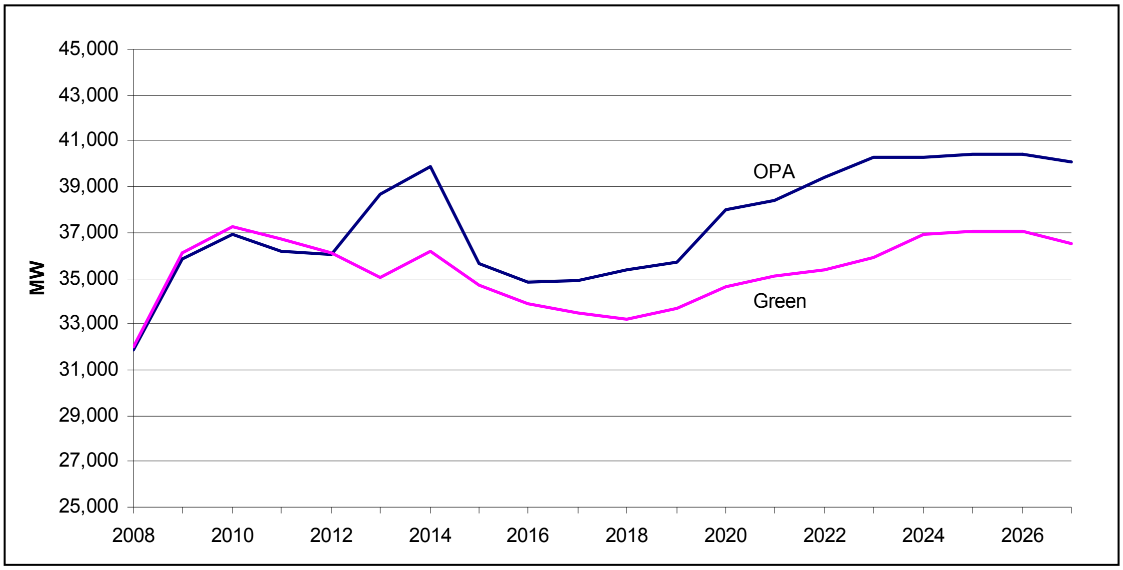
C. Green Base Case

The Green Base Case simulates a resource portfolio that is a reliable and economic mix of enhanced CDM, new renewables, and other clean resources. Annual installed capacity of the Green Base Case portfolio is detailed in Table GRN-A-1; corresponding effective capacities are provided in Table GRN-A-2.

> **SCGT and CCGT in the Green Cases**
>
> In order to satisfy reliability and energy requirements, the Green resource portfolios include new clean resources in addition to renewable resources and CDM. To simplify the analysis, we model these generic new resources as simple-cycle and combined-cycle gas turbine technology. However, these new gas units are used simply as proxies for potential clean technologies, such as community-based dispersed renewables, Ontario central-station renewables, imports of hydro and wind resources from Manitoba and Quebec, combined heat and power (CHP, including district energy systems), recycled energy, and storage. Modeling these clean resources as gas-fired generation understates the benefits of the Green portfolios, such as the transmission and distribution costs and losses avoided by local, customer-sited technologies, co-production of thermal energy, and reduced emissions.

The Green Base Case requires less planned capacity than in the OPA Reference Case, due to the substantial increase in CDM savings; see Figure 11. These additional savings reduce the need for new capacity to meet increased energy requirements, as well the need for new peaking capacity to provide planning reserves. In other words, the additional CDM allows for a reduction in planned capacity additions without diminishing system adequacy and reliability.

Figure 11: Installed Capacity: OPA Reference Case versus Green Base Case



As discussed in Section IV, the CDM savings and cost forecasts for the Green cases were developed by VEIC (introduced in the Evidence of Scudder Parker). VEIC developed forecasts for both a medium and an aggressive CDM case. We used the former in the Green Base Case and the latter in the Green Aggressive CDM Case. VEIC identifies and targets significantly greater CDM savings than reflected in the IPSP; see Table 17.

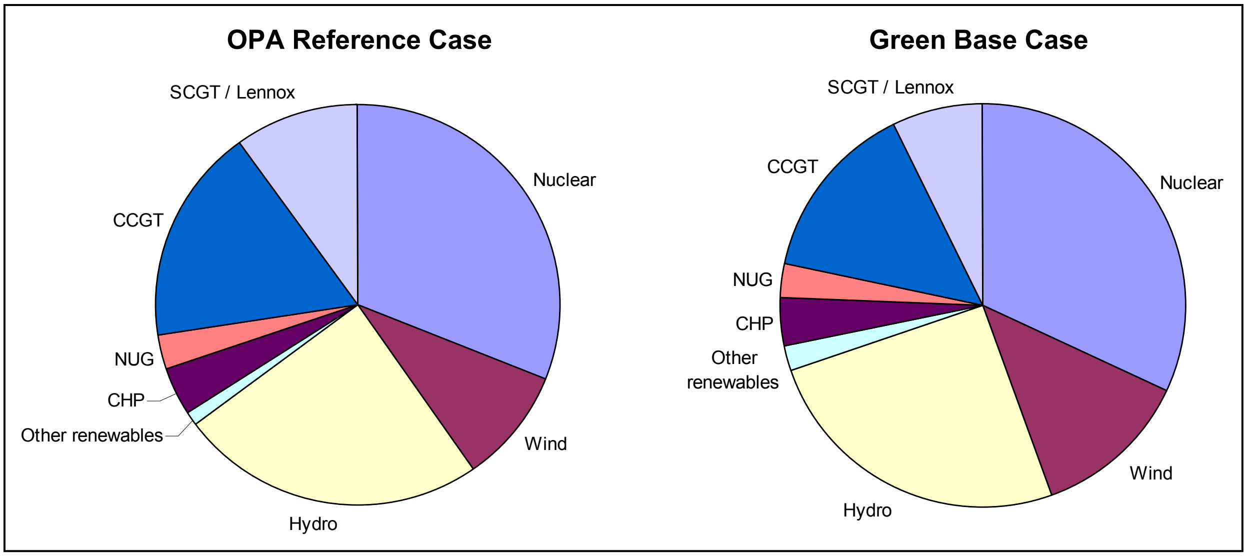
Table 17: CDM Savings by Scenario

	CDM Peak Savings in 2027	Basis for Case:
OPA	6,217 MW	OPA Reference; OPA Nuclear Capital Cost
VEIC Medium	10,651 MW	Green Base Case; Green Increased Peaking Case
VEIC Aggressive	12,652 MW	Green Aggressive CDM Case

Although the differences between the OPA Reference and Green Base portfolios are substantial, the supply mix is similar for the first half of the planning horizon.[39] In 2015, the Green Base Case has a slightly larger wind component and a slightly smaller gas-fired component; see Figure 12.

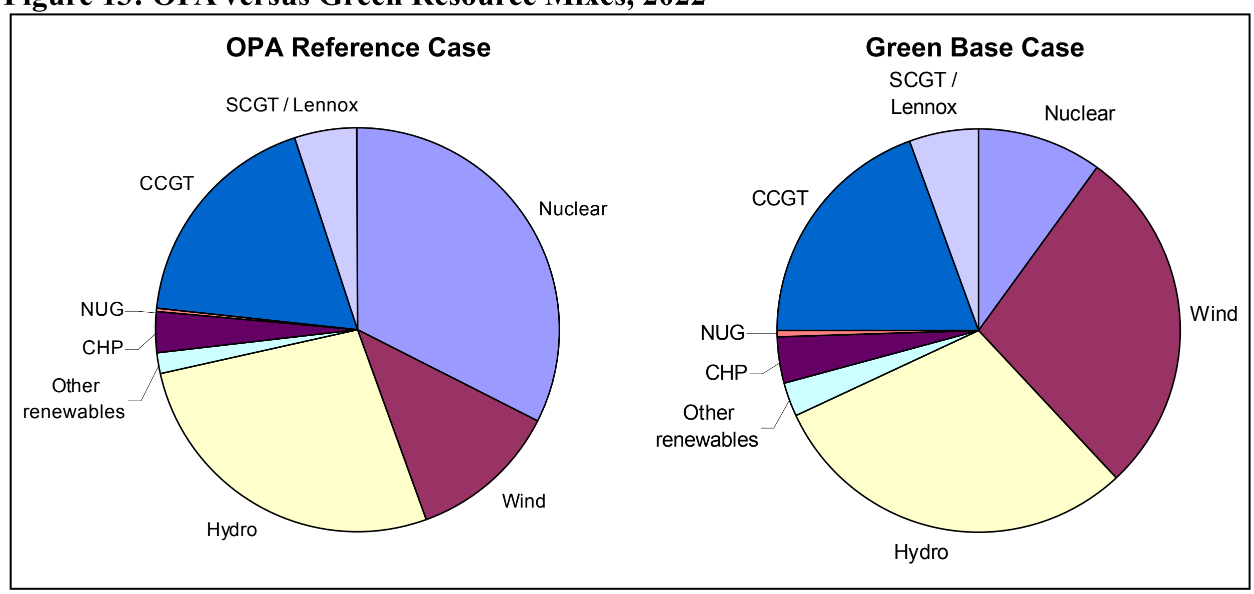
[39]This should not be taken as support for OPA's wait and see approach to CDM and CHP, as OPA's early commitment to nuclear would displace the opportunity for these more cost-effective resources in later years.

Figure 12: OPA versus Green Resource Mixes, 2015



But, the picture changes considerably in only a few years, as illustrated by the 2022 status in Figure 13. Here the Green Base Case contains far greater wind and far less nuclear than the OPA Reference case.

Figure 13: OPA versus Green Resource Mixes, 2022



From an energy perspective, the Green Base Case Portfolio is much more diverse and robust than the OPA Reference Case Portfolio. The OPA Reference Case portfolio relies on nuclear and hydro for almost 75% of its energy needs. In contrast, the Green Base Case portfolio minimizes reliance on any one type of resource, yielding a more reliable system, improved economics, greater operating flexibility, and less risk. See Table 18.

Table 18: 2022 Energy Contribution: OPA Reference Case vs. Green Base Case

	Nuclear	Hydro	Wind	CDM	All others
OPA Reference Case	50%	24%	6%	13%	6%
Green Base Case	14%	29%	15%	26%	15%

Capacity factors for the Green Base Case are generally comparable to those in the OPA Reference Case. Annual capacity factors for each resource are provided in Table GRN-A-5.

As with the OPA Reference Case, we model a sensitivity to the Green Base Case that increases nuclear outage rates by five percentage points. The results were similar to the sensitivity on the OPA Reference Case, but slightly less severe due to the lesser dependence on nuclear in the Green Base Case. In summary, the increase in nuclear forced outage rates has the following impacts on the Green Base Case results:

- Capacity factors decline by 5%.
- Nuclear output drops 5 TWh in the early years, with the loss dropping to only 1 TWh by 2027.
- Coal-fired generation increases only slightly due to the lost TWh in the early years.[40]
- Overall plan cost rises by $1.2 billion on an NPV basis

D. Green Increased Peaking Case

As noted above, the Green Base Case replaces all planned nuclear capacity in Case 1B with a mix of increased CDM, additional on-shore and off-shore wind, and additional clean resources. For modeling purposes, we represent the additional clean resources with a mix of CCGT and SCGT capacity. In general, we added CCGT capacity to fill the gap between energy production from planned nuclear capacity in Case 1B and that from additional CDM energy savings and wind output in the Green Base Case. Similarly, we added SCGT

[40]Note that procurement of additional CDM and CHP resources in early years could further reduce this potential reliance on coal as a stop-gap for shortfalls in nuclear performance.

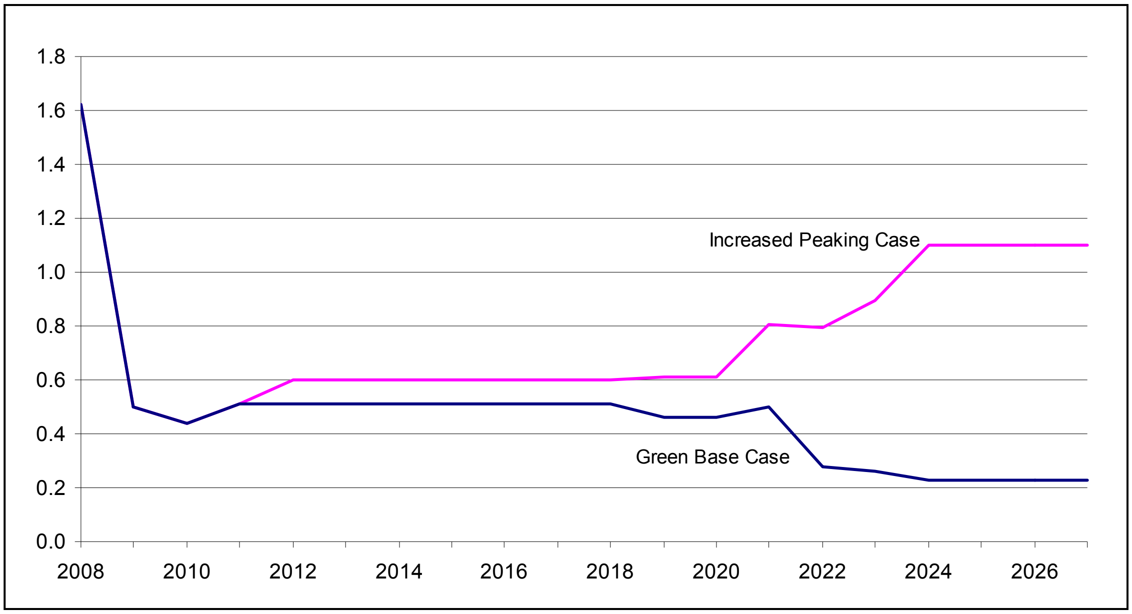
capacity to fill the gap in reserve capacity between that from planned nuclear capacity in Case 1B and that from additional CDM peak savings and wind effective capacity in the Green Base Case.

In order to test the economics of the particular mix of planned intermediate and peaking capacity adopted in the Green Base Case, we modeled a portfolio that replaced all planned CCGT capacity with equivalent SCGT capacity. In this case, the gap in energy production is filled in large part from increased dispatch of existing and committed CCGT, as well as from additional output from existing, committed, and planned peaking capacity.

Figure 14 illustrates the relative mix of peaking and intermediate capacity between the Green Base and Increased Peaking cases.[41] In the period before 2020, both cases are dominated by intermediate capacity. After 2020, when many of the planned gas resources come on line, the dominance of CCGT grows to a 4:1 ratio in Green Base Case. Our shifting of resources in the all-peaking case lowers this to an approximate 1:1 ratio. The details of installed and effective capacity for the Green Increased Peaking Case are listed in Tables GRN-B-1 and 2. Data on resulting reserve margins are in Table GRN-B-3, but are no different than the Green Base Case.

[41] Peakers include SCGTs and Lennox. In accordance with OPA's conventions, currently contracted NUGs are not considered in the CCGT category, but replacement NUGs are.

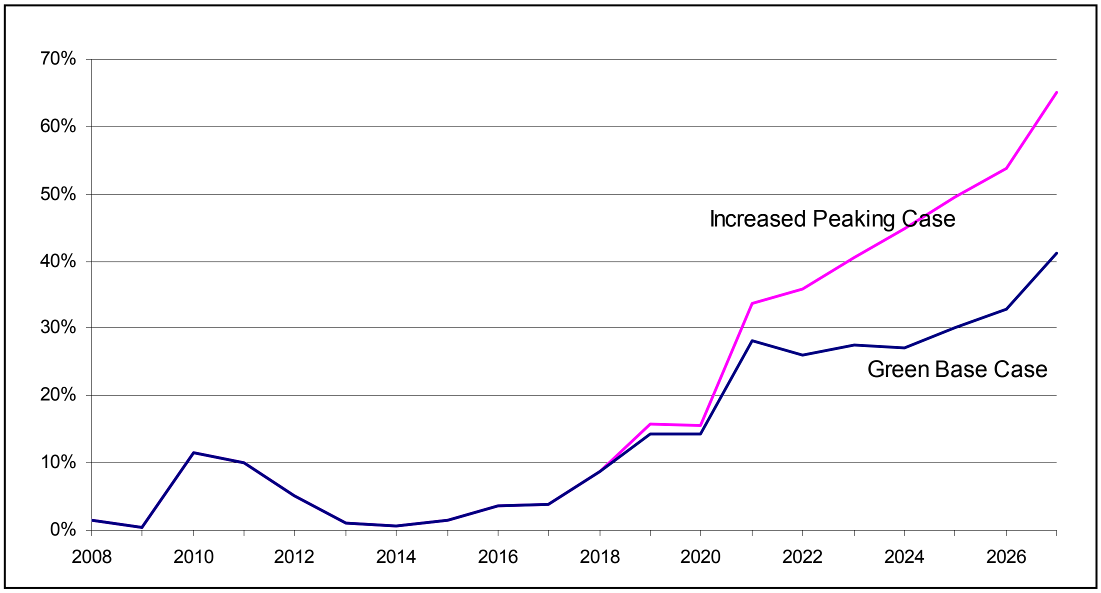
Figure 14: Ratio of Peaking to Intermediate MW



In our modeling of the Green Base Case, CCGT generation was minimal and SCGT generation was almost non-existent. This is to be expected given the large amounts of baseload generation in all of the cases. In fact, CCGT capacity factors never get above 20% until late in the plan period, and then average about 30%. Meanwhile, peakers have capacity factors of 0-1%. It therefore is clear that gas-fired units are primarily necessary for capacity, not energy, in any of the scenarios. This of course argues for more peaking capacity and less intermediate capacity.

As such, the swap of peaking for planned intermediate capacity in the Green Increased Peaking Case provides twin benefits of reduced investment costs for planned capacity and greater operating efficiency for the remaining CCGT units. This is clear from the improved capacity factors detailed in Table GRN-B-5 and illustrated in Figure 15.

Figure 15: Capacity Factors for Intermediate Units



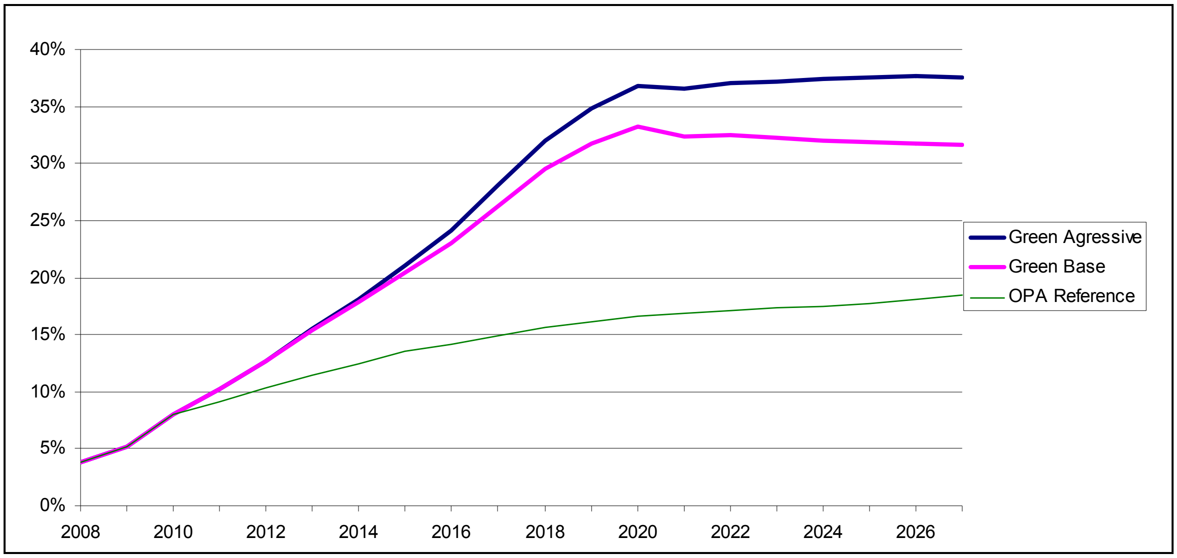
However, the cost analysis, while favoring an all-peaking mix, does not provide a compelling case. On an NPV basis, the two cases are essentially equal. And although less investment is required (since peaking capacity has lower installation cost), this small advantage is dissipated by the discounting process. Details on annual costs for the Green Increased Peaking Case are in Table GRN-B-6.

E. Green Aggressive CDM Case

The Green Aggressive CDM Case differs from the Green Base Case with respect to the forecast of annual CDM savings and costs. In the former case, we utilize VEIC's forecast of savings and costs for their aggressive CDM scenario.

Figure 16 illustrates the relative levels of conservation estimated by OPA and VEIC. The increased savings in the Aggressive CDM scenario reduces the need for new clean resources, and the results are detailed in Tables GRN-C-1 through 3. As both OPA and VEIC assumed load factors for CDM less than the system load factor, the energy benefits are not as great, but are nonetheless substantial.

Figure 16: CDM as Percent of Peak Demand



The additional savings relative to the medium CDM scenario allow for 2,000 MW less planned CCGT capacity in the Green Aggressive CDM Case than in the Green Base Case. The reduction in fixed and variable supply costs is offset by the increase in spending on CDM, yielding savings somewhat less than $1 billion on an NPV basis. Details of annual costs are shown in Table GRN-C-6. This case illustrates that larger CDM savings can be pursued cost-effectively, and that the added sustainability benefits, such as lower environmental impact, and increased reliability do not carry a net financial cost. This suggests that a strategy of aiming high on CDM is warranted.

VIII. Untapped Resources and Benefits

A. Rate Design and Real-Time Data for Consumers

In addition to the programs that are the basis for VEIC's estimates of conservation potential, Ontario can reduce energy usage and peak loads through improved rate design and by providing real-time load information to consumers. These pricing and data programs can support and facilitate customer participation in the conservation programs, in addition to directly changing customer behavior. Such programs include the following pricing and data options:

- shifting fixed charges (such as customer and demand charges) to energy rates;
- decreasing energy rates for low-usage levels and using the extra revenues to increase tail-block rates;
- implementing time-of-use (TOU) rates, which charge more in periods with generally higher costs than in low-cost periods;
- implementing real-time rates, which charge more in the actual hours with the highest loads, smallest reserves and highest market prices;
- providing real-time feedback to customers on their energy usage, to help them identify and understand the equipment and behavior that increase their energy usage and bills. The real-time feedback can be used alone or with TOU or real-time rates;
- installing meters for individual apartments or businesses in buildings that are currently served through a single meter.

Five recent studies in Ontario provide useful information on the effect of some of these approaches (OEB 2007; Hydro One Networks Inc. 2008; Navigant Consulting 2008a; 2008b; 2008c). Taken as a whole, the studies suggest the following conclusions:

- Time-of-use rates can reduce peak-period usage by several percent, even in the short term. As customers install equipment and learn to shift energy more effectively, these effects may increase. Since Ontario is installing smart meters for all customers, the incremental cost of implementing TOU rates should be minimal.
- Pricing signals in real time can produce much larger reductions—about 20%—for a few hours on a few critical days. Once smart meters are installed, implementing critical-period pricing requires only a mechanism for informing customers when a critical period occurs.
- In addition to shifting loads, TOU rates encourage conservation, resulting in 3%–6% reductions in total usage.
- Systems that allow customers to monitor their usage conveniently in real time lead to 4%–7% reductions in usage. If used in conjunction with TOU rates, monitors appear to increase the amount of energy shifted off the peak period. Those monitors help customers understand how they use energy, determine the effectiveness of conservation behaviors, and identify inefficient equipment, which will help them decide which CDM programs they should participate in. At a cost of about $150 installed, the monitors appear to cost only about 2¢/kWh saved.
- A switch from bulk-metering to individual metering of residential apartments and condominiums (that is, from essentially no energy price signal to full retail rates) reduces energy usage by 22%.

Combinations of improved rate design, real-time information devices, and conversion of bulk-metered customers to individual meters may reduce Ontario loads by 10% or so.[42] These reductions may replace or supplement the savings estimated by VEIC.

[42]In Exhibit D-4-1 (Tables 14 and 15), OPA appears to credit smart meters with some capacity savings, but almost no energy savings.

B. Additional Benefits of Distributed Resources

Distributed resources comprise energy efficiency, demand response, customer-sited generation (e.g., photovoltaics, CHP, and some small wind), and small generators (and potentially storage) connected to distribution lines or distribution substations. Each of these resources has technology-specific characteristics that may increase its benefits (e.g., the high ELCC per MW for energy efficiency, thermal energy from CHP, reduced emissions).

In addition, distributed resources provide, to varying extent, two groups of benefits that central generation does not: reducing line losses and providing local reliability without the need for investments in transmission and, in many cases, distribution.

Table 19: Additional Benefits from Distributed Resources by Resource Type

	Losses Benefits		Investment Benefits	
	Transmission	*Distribution*	*Transmission*	*Distribution*
Energy Efficiency	Y	Y	Y	Y
Demand Response	Y	Y	Varies	Varies
Customer-Side Generation	Y	Y	Y	Some
Generation on the Distribution System	Y	N	Y	N

Demand response only avoids transmission and distribution investment if the response occurs at the times of local maximum stress on the transmission-and-distribution system, which may occur at the time of the local peak demand or when other equipment fails, shifting load onto the available equipment.[43] Customer-side generation, especially if that generation is either small compared to load on the distribution system or highly correlated with load (as for PV solar), is likely to avoid primary distribution and substation investment but is less likely to avoid costs of line transformers or the secondary system, since a customer's undiversified load may peak when the generator is off line.

In situations in which load reductions do not avoid growth-related T&D investment, they will nonetheless tend to increase reserve margins on the T&D

[43]Loads on a transmission line or substation may increase due to failure of another transmission line or substation or of generation. Loads on a distribution substation or primary circuit may increase due to the failure of other distribution equipment, or of transmission serving other equipment.

system, improving reliability and extending the life of equipment (which will decrease future replacement costs).

Losses

The losses avoided by energy from distributed resources are the marginal variable losses in the conductors of lines and transformers. The other major components of losses are the no-load, fixed losses that occur in the core of any energized transformer. The losses in any line equal the current times the voltage drop over the line. The voltage drop, in turn, equals the current times the resistance of the line. Hence, the losses vary with the square of the current, and since the voltage on any part of the electrical system is held nearly constant, with the square of the load. The normal convention is to represent current by I and resistance by R, so losses at any load I is

$$\text{loss} = I^2 \times R$$

the average loss as a fraction of load is

$$\text{loss as fraction of load} = I^2 \times R \div I = I \times R$$

and the marginal loss is the derivative of $I^2 \times R$, or

$$\text{marginal loss} = 2I \times R$$

A reduction in energy flow through the delivery system reduces losses by the marginal loss factor for that load level.[44] A reduction in load at peak would also reduce losses by the marginal loss factor (which would be quite high), but to the extent that the load reduction also reduces investment in the T&D system, line losses would tend to rise.[45] Marginal-cost analyses commonly (and mistakenly) assume that the avoided losses at peak are the average losses at that load level.

Transmission Line Losses

We have two sources of estimates of losses on the transmission system. In Exhibit I-31-6, OPA provided an IESO study, which indicates that a uniform load reduction across the province of 200 MW in high-load hours would decrease transmission losses about 21.5 MW (10.8%). The study also shows

[44]The approximation is quite close for radial systems and distribution. Since the mix and location of generation used to serve load varies with the load level, transmission losses can vary in more complex ways. OPA has provided only limited information regarding transmission losses.

[45]As discussed below, when loads are falling over time, additional load reductions may not avoid much T&D investment, so the marginal-loss value may be relevant.

that a comparable load reduction solely in the GTA would reduce transmission losses by about 26.2 MW (13.1%). The province-wide average is more appropriate for our purposes. This peak marginal loss rate would suggest average variable losses at peak of 5.4%, and average variable losses over the year (at an average load of 65% of peak) of 3.5%. This extrapolation assumes similar energy flow patterns for all load levels. If baseload generation tends to be electrically close to load, and peaking supplies are remote, average losses will be lower than the extrapolation indicates, and vice versa.

In Exhibit I-1-70 (p.11), OPA assumes that average annual transmission line losses are about 2.5%. That estimate is less than the average energy losses we estimate from OPA's estimate of the marginal peak losses. We split the difference and assume 3% average annual energy losses, with 2.5% variable. Marginal transmission losses for energy are then about 5%.

Distribution Line Losses

In Exhibit I-31-6, OPA reports average distribution line losses of 4.2%, based on the 2005 data submitted by distributors under the OEB's Reporting and Record Keeping Requirements. The 4.2% loss factor is the difference between wholesale MWh received and the distributors' reported retail energy deliveries, averaged over all classes.

This loss estimate value may be understated. While virtually all end-use loads are served at secondary voltages, energy is delivered to many large customers at primary voltages, so losses in the line transformer and secondary lines are borne directly by the customer and are not subtracted from the retail delivery data provided by the distributors.[46]

Assuming that the 4.2% average annual distribution loss factor is about right, and that the fixed losses are 1% of average energy usage, the average variable losses would be about 3.2% and the average marginal losses would be about 6.4%. Average variable losses at peak would be about 3.2% ÷ 0.65 = 4.9%, and fixed losses would be about 1% × 0.65 = 0.65%, for total average losses at peak of about 5.6%. Marginal losses at peak would be about 9.8%.

Total Losses

Based on the data above, total marginal energy losses from customer to generator would be about 11.7%. Average demand losses at peak would be

[46] Hydro One also serves customers directly at sub-transmission voltage (EB-2007-0681, Exhibit G1-2-3).

about 11.3%, and marginal losses at peak (assuming no change in the T&D system) would be about 21.7%.

Avoided T&D Costs

Reducing loads with CDM reduces required investment in transmission and distribution. We estimate below a total avoided T&D cost of $180/kW-year in 2007 dollars.

Avoided Transmission Costs

The OPA uses an avoided transmission cost of $4.30/kW-yr (2007 dollars), based on restatement of an estimate developed by Navigant (Exhibit D-4-1 Attachment 15). Navigant does not provide the computation of its estimate, but does explain (pp. 19–20) that its analysis includes only "upgrades for local area load growth" because other "transmission system investments… are not driven by load growth or conversely cannot be deferred by reductions in load growth…. These include…interconnection upgrades [and] transmission congestion relief." Navigant does not explain why it believes that load growth does not affect the extent of transmission congestion or the need for transmission delivery facilities in the decades-long context of system planning. In any case, Navigant is incorrect. Those misconceptions may have caused Navigant to ignore additions in HONI's Load Customer Connections and Inter-Area Network Transfer Capability categories.

We start with the Development investments in 2003 through 2008 identified in HONI's most recent distribution rate proceeding, RP-2005-0020/EB-2005-0378, Exhibit D1-3-1, Table 1.[47] We subtract the costs of the interconnection to Hydro Quebec and the generation-related transmission connecting Bruce nuclear and wind generation (from RP-2005-0020/EB-2005-0378, Exhibit D2-2-2) and add 2% annual inflation to restate the costs in 2007 dollars. The total investment in this period was $1.15 billion in 2007 dollars.

We estimate the load driving these investments to be the difference between the actual 2002 weather-adjusted summer peak of 24,272 MW (Exhibit I-22-47) and the IPSP 2008 peak forecast of 26,515 MW (Exhibit D-1-1, Table 1). That difference—a mix of load served at secondary, primary and sub-transmission—is 2,243 MW, for an investment of $512 per kW of load growth.

[47]This was the only source OPA identified for load-related transmission costs.

Applying OPA's 4% real financing cost for HONI and a 30-year life, we estimate a 5.8% carrying charge. HONI reports transmission OM&A (excluding development OM&A) of about 3.8% of average gross assets (EB-2005-0501, Exhibits C1-2-1 and D1-1-1). Hence the annual avoided transmission cost per kilowatt of load reduction would be $512 × (5.8% + 3.8%) = $49/kW-yr in 2007 dollars.[48] The loads used in this computation are at the generation level, so a reduction on peak at the customer meter, including losses, would avoid about $55/kW-year.

Avoided Distribution Costs

The OPA uses an avoided distribution cost of $4.30/kW-yr (in 2007 dollars), which it says is restated from $6.66/kW-yr (2006 dollars) in the OEB Total Resource Cost Guide (Exhibit I-22-35).[49] The Total Resource Cost Guide cites Hydro One Networks Inc. (2005). That document, in turn, provides only an "illustrative example," computing the avoided cost for 180 MW of load reduction that defers a $19.92 million addition for three years, starting in 2009. The addition may represent more than one project, but HONI considered only projects planned for 2006, and included only some portion of those.

These estimates are clearly understated.

- Hydro One Networks Inc. (2005) reports that the 180 MW was intended to be equal to demand growth (apparently for three years), yet HONI assumed that it would defer only about $20 million, out of some $59 million of additions HONI projected for 2006 (RP-2005-0020/EB-2005-0378). That value includes $36.2 million of system capability requirements, $21.2 million of service upgrades, and $1.1 million of additional spare distribution transformers.
- The analysis also ignores the load-related distribution additions planned for 2010–2012 that would be deferred by the elimination of load growth for 2009–2012.
- Hydro One assumed that CDM would reduce 2009 load by the equivalent of three years of load growth. Hence, two-thirds of the load reductions have

[48]The OPA uses a 7.4% real-levelized carrying charge, based on a 20-year life. We consider that life to be unrealistically short for transmission.

[49]The Total Resource Cost Guide that OPA provided as Attachment 1 to Exhibit I-22-35 actually shows distribution avoided costs of $7.17/kW-yr in 2009 dollars.

no effect in 2009 and one-third of the load reductions have no effect in 2010. Had HONI assumed that the load reductions occurred smoothly over the three years, it would have assumed fewer MW-years of load reduction and estimated a 38% higher $/kW-year value.

We computed a revised avoided distribution cost for HONI, using the identifiable load-related additions for 2003 through 2006 from RP-2005-0020/EB-2005-0378, a total of $238 million in 2007 dollars (assuming 2% inflation). We divided that investment by the growth in HONI's summer maximum peak from 2002 (3,548 MW) to 2006 (3,775 MW), from OEB (2008).[50] The marginal investment per unit of load growth was $1,050/kW-year.

Hydro One reports distribution OM&A (excluding development and customer-care OM&A) of about 5.4% of average gross assets (EB-2005-0501, Exhibits C1-2-1 and D1-1-1). Including the 5.8% carrying charge, the annual avoided transmission cost per kilowatt of load reduction would be $1,050 × (5.8% + 5.4%) = $117/kW-yr in 2007 dollars. The avoided cost all the way to the end use would be somewhat greater, since it would include transformers and internal distribution of customers served above secondary. The loads used in this computation were at the input to the distribution system; including 5.4% peak losses on the transmission system, the avoided cost would be about $123/kW-yr.

We compared these results to those of Choynowski (1987) of Ontario Hydro's Rate Economics Section. That study consisted of a series of regression analyses of peak load and distribution costs, both capital and OM&A. Choynowski reduced his initial estimate of avoided capital costs by 30%, to take out a rough estimate of capitalized overhead costs. Following this adjustment, the study estimated the marginal distribution cost to be $32.95/kW-yr for the municipal utilities, without losses or overheads, in 1987 dollars.[51]

Choynowski should not have removed capitalized overheads. Most of these overheads are related to employee benefits, supervision, and other costs that vary with the amount of T&D construction. Retaining overheads in capital, and adding them to OM&A, would increase the avoided distribution cost to about

[50] Weather-adjusting the summer loads or using winter load growth would result in slower growth and greater dollars per kW.

[51] Choynowski assumed a 5% real interest rate and a 30-year equipment life.

$47/kW-yr in 1987 dollars. This is very similar to the marginal distribution cost estimated by Ontario Hydro's Branch Comptroller for Ontario Hydro's rural retail service territory (now served by Hydro One), and cited by Choynowski: $51.09/kW-yr in 1987 dollars.

Adding 63% CPI inflation from the Bank of Canada,[52] the 1987 estimates would be about $82/kW-year in 2007 dollars. This revised value is less that our estimate but is more than an order of magnitude greater than OPA's estimate.

C. Renewable Purchases and Interchange

Although not explicitly modeled in the Green cases, Ontario may be able to rely on firm purchases and sales with surrounding control areas to import additional renewable power or to provide firming services for internal renewable resources. For example, Ontario may be able to purchase renewable energy from hydro and/or wind resources in Manitoba and/or Quebec. However, such purchases are likely to be priced at the seller's opportunity costs, which would probably be set at the cost of replacing CCGT in New England and New York (for Quebec) or at the cost of replacing CCGT and coal capacity in Minnesota (for Manitoba).

Firm purchases of storage services from Manitoba and/or Quebec are more likely to be economically superior to available Ontario resources. Both provinces have large amounts of hydro capacity and plans for developing more. The water available for their hydro plants is generally not sufficient to operate the plants at full capacity, so they can accept energy at times of low load or prices by reducing hydro output and then return that energy at higher-value times by increasing hydro output.

Both Manitoba Hydro and Hydro Quebec currently use this flexibility to purchase power from the U.S., Ontario, and elsewhere when prices are low and sell the energy back when prices are higher. The hydro-based utilities would be expected to charge Ontario their opportunity cost for any flexibility they would lose due to a storage contract with Ontario. Ontario may be able to offset that price by (1) substituting a firm capacity price for uncertain energy-market

[52]Online calculator at www.bankofcanada.ca/en/rates/inflation_calc.html.

revenues and (2) guaranteeing the hydro systems access to Ontario energy reserves (including insurance) at favorable rates during drought conditions.

Depending on the scale of the storage contracts, additional interconnection transmission may be required. In the case of Manitoba, the transmission could potentially be integrated with increased wind development in northwest Ontario.

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Appendix: Detailed Modeling Results

Table OPA-A-1: Installed Capacity (MW)
Case OPA-A - OPA Reference Case

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Nuclear	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
Wind	659	1,447	1,646	1,961	2,110	2,513	3,040	3,250	3,472	3,694	4,055	4,270	4,685	4,685	4,685	4,685	4,685	4,685	4,685	4,685
Hydro	7,843	7,849	7,940	7,986	8,075	8,570	8,700	8,754	8,944	8,957	8,965	9,108	9,967	10,114	10,615	10,615	10,644	10,779	10,779	10,779
Other renewables	118	157	177	177	238	278	321	389	550	563	576	580	627	627	627	627	627	627	627	627
CHP	353	500	736	736	736	1,322	1,322	1,322	1,322	1,322	1,322	1,322	1,322	1,322	1,322	1,322	1,322	1,322	1,322	1,322
NUG	1,517	1,517	1,517	1,512	1,512	1,347	1,347	1,043	936	730	275	275	275	275	144	144	144	144	144	144
CCGT	1,340	4,343	4,943	4,943	4,943	5,958	5,958	6,262	6,369	6,575	7,030	7,155	7,155	7,155	7,155	7,155	7,155	7,155	7,155	7,280
SCGT / Lennox	2,174	2,174	2,174	2,524	2,974	2,974	3,524	3,524	3,524	3,849	4,099	4,099	4,099	3,049	1,999	1,999	1,999	1,999	1,999	1,999
Coal	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
Total	31,857	35,840	36,946	36,187	36,030	38,658	39,909	35,634	34,843	34,901	35,346	35,686	38,007	38,391	39,406	40,287	40,316	40,451	40,451	40,061

Table OPA-A-2: Effective Capacity (MW)
Case OPA-A - OPA Reference Case

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Nuclear	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
Wind	132	289	329	392	422	503	608	650	694	739	811	854	937	937	937	937	937	937	937	937
Hydro	6,039	6,044	6,114	6,149	6,217	6,599	6,699	6,740	6,887	6,897	6,903	7,013	7,675	7,788	8,174	8,174	8,196	8,300	8,300	8,300
Other renewables	118	157	177	177	238	278	321	389	550	563	576	580	627	627	627	627	627	627	627	627
CHP	353	500	736	736	736	1,322	1,322	1,322	1,322	1,322	1,322	1,322	1,322	1,322	1,322	1,322	1,322	1,322	1,322	1,322
NUG	1,517	1,517	1,517	1,512	1,512	1,347	1,347	1,043	936	730	275	275	275	275	144	144	144	144	144	144
CCGT	1,340	4,343	4,943	4,943	4,943	5,958	5,958	6,262	6,369	6,575	7,030	7,155	7,155	7,155	7,155	7,155	7,155	7,155	7,155	7,280
SCGT / Lennox	2,174	2,174	2,174	2,524	2,974	2,974	3,524	3,524	3,524	3,849	4,099	4,099	4,099	3,049	1,999	1,999	1,999	1,999	1,999	1,999
Coal	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
Total	29,526	32,877	33,803	32,782	32,484	34,676	35,475	31,020	30,008	29,885	30,040	30,175	31,967	32,317	33,217	34,098	34,120	34,224	34,224	33,834

Table OPA-A-3: Supply Requirements
Case OPA-A - OPA Reference Case

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Peak demand	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
Less CDM	-1,006	-1,375	-2,162	-2,490	-2,819	-3,148	-3,476	-3,805	-4,021	-4,284	-4,553	-4,765	-4,966	-5,128	-5,290	-5,449	-5,613	-5,760	-5,990	-6,217
Net peak demand	25,509	25,374	24,824	24,715	24,607	24,500	24,397	24,294	24,436	24,536	24,634	24,794	24,970	25,316	25,670	26,036	26,407	26,803	27,125	27,460
Effective capacity	29,526	32,877	33,803	32,782	32,484	34,676	35,475	31,020	30,008	29,885	30,040	30,175	31,967	32,317	33,217	34,098	34,120	34,224	34,224	33,834
Effective reserve margin	4,017	7,503	8,979	8,067	7,877	10,176	11,078	6,726	5,572	5,349	5,406	5,381	6,997	7,001	7,547	8,062	7,713	7,421	7,099	6,374
% Reserves	16%	30%	36%	33%	32%	42%	45%	28%	23%	22%	22%	22%	28%	28%	29%	31%	29%	28%	26%	23%

Table OPA-A-4: Generation (TWh)
Case OPA-A - OPA Reference Case

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Nuclear	81	79	78	81	88	90	89	81	69	66	65	63	70	80	92	99	99	98	99	95
Wind	2	4	4	5	5	6	7	8	9	9	10	10	11	11	11	11	11	11	11	11
Hydro	42	42	42	41	39	39	39	42	46	47	47	48	49	47	45	43	44	45	46	48
Other renewables	0	0	0	0	1	1	1	1	2	2	3	3	2	2	1	1	1	1	1	2
CHP	1	2	3	3	3	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
NUG	10	10	10	10	10	9	9	7	6	5	2	2	2	2	1	1	1	1	1	1
CCGT	0	0	0	0	0	0	0	6	13	16	20	21	13	8	4	3	3	4	5	8
SCGT / Lennox	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Coal	17	17	14	10	6	3	3	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	154	154	151	151	152	153	153	150	149	150	151	152	154	156	159	163	165	166	168	170

Table OPA-A-5: Capacity Factor (%)
Case OPA-A - OPA Reference Case

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Nuclear	81%	79%	78%	82%	83%	83%	82%	83%	81%	82%	82%	81%	81%	82%	82%	82%	82%	82%	83%	82%
Wind	28%	28%	28%	28%	28%	28%	28%	28%	28%	28%	28%	28%	28%	28%	28%	28%	28%	28%	28%	28%
Hydro	62%	61%	60%	59%	56%	52%	51%	54%	58%	60%	60%	60%	56%	53%	48%	46%	47%	48%	48%	51%
Other renewables	42%	35%	30%	27%	25%	21%	20%	29%	42%	48%	53%	55%	45%	37%	25%	20%	22%	26%	27%	34%
CHP	41%	41%	41%	41%	41%	41%	41%	41%	41%	41%	41%	41%	41%	41%	41%	41%	41%	41%	41%	41%
NUG	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%
CCGT	2%	1%	0%	1%	1%	0%	0%	11%	22%	28%	32%	33%	21%	14%	6%	4%	5%	7%	7%	12%
SCGT / Lennox	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Coal	30%	29%	24%	24%	19%	11%	11%													
Total	55%	49%	47%	48%	48%	45%	44%	48%	49%	49%	49%	49%	46%	46%	46%	46%	47%	47%	48%	48%

Table OPA-A-6: Annual Costs (million C$)
Case OPA-A - OPA Reference Case

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Nuclear	469	458	453	471	511	524	514	470	403	382	2,149	3,976	6,247	9,483	11,562	12,644	12,646	12,642	12,648	12,622
Wind	0	0	0	75	111	204	326	373	422	470	552	597	691	686	682	678	674	670	666	666
Hydro	8	9	22	36	58	152	186	200	244	248	250	284	482	515	631	631	640	671	671	671
Other renewables	24	24	22	20	43	54	70	115	215	227	239	242	250	240	225	219	222	226	228	236
CHP	102	144	187	176	170	403	402	402	402	402	402	402	402	402	402	402	402	402	402	402
NUG	852	852	754	706	680	606	606	469	421	328	124	124	124	124	65	65	65	65	65	65
CCGT	20	27	13	20	29	124	123	582	1,045	1,328	1,619	1,722	1,193	840	512	429	467	545	568	800
SCGT / Lennox	7	0	0	43	72	72	108	109	116	143	161	162	149	135	124	124	124	124	124	125
Coal	963	954	865	661	398	322	319	0	0	0	0	0	0	0	0	0	0	0	0	0
CDM	369	450	746	590	605	603	616	625	478	469	478	457	442	399	402	393	414	353	505	500
Total	2,814	2,918	3,063	2,798	2,677	3,064	3,269	3,346	3,746	3,998	5,973	7,966	9,979	12,824	14,607	15,585	15,654	15,698	15,877	16,087

Table OPA-B-1: Installed Capacity (MW)
Case OPA-B - OPA Nuclear Cap Costs

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Nuclear	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
Wind	659	1,447	1,646	1,961	2,110	2,513	3,040	3,250	3,472	3,694	4,055	4,270	4,685	4,685	4,685	4,685	4,685	4,685	4,685	4,685
Hydro	7,843	7,849	7,940	7,986	8,075	8,570	8,700	8,754	8,944	8,957	8,965	9,108	9,967	10,114	10,615	10,615	10,644	10,779	10,779	10,779
Other renewables	118	157	177	177	238	278	321	389	550	563	576	580	627	627	627	627	627	627	627	627
CHP	353	500	736	736	736	1,322	1,322	1,322	1,322	1,322	1,322	1,322	1,322	1,322	1,322	1,322	1,322	1,322	1,322	1,322
NUG	1,517	1,517	1,517	1,512	1,512	1,347	1,347	1,043	936	730	275	275	275	275	144	144	144	144	144	144
CCGT	1,340	4,343	4,943	4,943	4,943	5,958	5,958	6,262	6,369	6,575	7,030	7,155	7,155	7,155	7,155	7,155	7,155	7,155	7,155	7,280
SCGT / Lennox	2,174	2,174	2,174	2,524	2,974	2,974	3,524	3,524	3,524	3,849	4,099	4,099	4,099	3,049	1,999	1,999	1,999	1,999	1,999	1,999
Coal	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
Total	31,857	35,840	36,946	36,187	36,030	38,658	39,909	35,634	34,843	34,901	35,346	35,686	38,007	38,391	39,406	40,287	40,316	40,451	40,451	40,061

Table OPA-B-2: Effective Capacity (MW)
Case OPA-B - OPA Nuclear Cap Costs

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Nuclear	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
Wind	132	289	329	392	422	503	608	650	694	739	811	854	937	937	937	937	937	937	937	937
Hydro	6,039	6,044	6,114	6,149	6,217	6,599	6,699	6,740	6,887	6,897	6,903	7,013	7,675	7,788	8,174	8,174	8,196	8,300	8,300	8,300
Other renewables	118	157	177	177	238	278	321	389	550	563	576	580	627	627	627	627	627	627	627	627
CHP	353	500	736	736	736	1,322	1,322	1,322	1,322	1,322	1,322	1,322	1,322	1,322	1,322	1,322	1,322	1,322	1,322	1,322
NUG	1,517	1,517	1,517	1,512	1,512	1,347	1,347	1,043	936	730	275	275	275	275	144	144	144	144	144	144
CCGT	1,340	4,343	4,943	4,943	4,943	5,958	5,958	6,262	6,369	6,575	7,030	7,155	7,155	7,155	7,155	7,155	7,155	7,155	7,155	7,280
SCGT / Lennox	2,174	2,174	2,174	2,524	2,974	2,974	3,524	3,524	3,524	3,849	4,099	4,099	4,099	3,049	1,999	1,999	1,999	1,999	1,999	1,999
Coal	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
Total	29,526	32,877	33,803	32,782	32,484	34,676	35,475	31,020	30,008	29,885	30,040	30,175	31,967	32,317	33,217	34,098	34,120	34,224	34,224	33,834

Table OPA-B-3: Supply Requirements
Case OPA-B - OPA Nuclear Cap Costs

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Peak demand	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
Less CDM	-1,006	-1,375	-2,162	-2,490	-2,819	-3,148	-3,476	-3,805	-4,021	-4,284	-4,553	-4,765	-4,966	-5,128	-5,290	-5,449	-5,613	-5,760	-5,990	-6,217
Net peak demand	25,509	25,374	24,824	24,715	24,607	24,500	24,397	24,294	24,436	24,536	24,634	24,794	24,970	25,316	25,670	26,036	26,407	26,803	27,125	27,460
Effective capacity	29,526	32,877	33,803	32,782	32,484	34,676	35,475	31,020	30,008	29,885	30,040	30,175	31,967	32,317	33,217	34,098	34,120	34,224	34,224	33,834
Effective reserve margin	4,017	7,503	8,979	8,067	7,877	10,176	11,078	6,726	5,572	5,349	5,406	5,381	6,997	7,001	7,547	8,062	7,713	7,421	7,099	6,374
% Reserves	16%	30%	36%	33%	32%	42%	45%	28%	23%	22%	22%	22%	28%	28%	29%	31%	29%	28%	26%	23%

Table OPA-B-4: Generation (TWh)
Case OPA-B - OPA Nuclear Cap Costs

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Nuclear	81	79	78	81	88	90	89	81	69	66	65	63	70	80	92	99	99	98	99	95
Wind	2	4	4	5	5	6	7	8	9	9	10	10	11	11	11	11	11	11	11	11
Hydro	42	42	42	41	39	39	39	42	46	47	47	48	49	47	45	43	44	45	46	48
Other renewables	0	0	0	0	1	1	1	1	2	2	3	3	2	2	1	1	1	1	1	2
CHP	1	2	3	3	3	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
NUG	10	10	10	10	10	9	9	7	6	5	2	2	2	2	1	1	1	1	1	1
CCGT	0	0	0	0	0	0	0	6	13	16	20	21	13	8	4	3	3	4	5	8
SCGT / Lennox	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Coal	17	17	14	10	6	3	3	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	154	154	151	151	152	153	153	150	149	150	151	152	154	156	159	163	165	166	168	170

Table OPA-B-5: Capacity Factor (%)
Case OPA-B - OPA Nuclear Cap Costs

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Nuclear	81%	79%	78%	82%	83%	83%	82%	83%	81%	82%	82%	81%	81%	82%	82%	82%	82%	82%	83%	82%
Wind	28%	28%	28%	28%	28%	28%	28%	28%	28%	28%	28%	28%	28%	28%	28%	28%	28%	28%	28%	28%
Hydro	62%	61%	60%	59%	56%	52%	51%	54%	58%	60%	60%	60%	56%	53%	48%	46%	47%	48%	48%	51%
Other renewables	42%	35%	30%	27%	25%	21%	20%	29%	42%	48%	53%	55%	45%	37%	25%	20%	22%	26%	27%	34%
CHP	41%	41%	41%	41%	41%	41%	41%	41%	41%	41%	41%	41%	41%	41%	41%	41%	41%	41%	41%	41%
NUG	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%
CCGT	2%	1%	0%	1%	1%	0%	0%	11%	22%	28%	32%	33%	21%	14%	6%	4%	5%	7%	7%	12%
SCGT / Lennox	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Coal	30%	29%	24%	24%	19%	11%	11%													
Total	55%	49%	47%	48%	48%	45%	44%	48%	49%	49%	49%	49%	46%	46%	46%	46%	47%	47%	48%	48%

Table OPA-B-6: Annual Costs (million C$)
Case OPA-B - OPA Nuclear Cap Costs

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Nuclear	469	458	453	471	511	524	514	470	403	382	1,560	2,779	4,310	6,491	7,903	8,638	8,641	8,637	8,643	8,617
Wind	0	0	0	75	111	204	326	373	422	470	552	597	691	686	682	678	674	670	666	666
Hydro	8	9	22	36	58	152	186	200	244	248	250	284	482	515	631	631	640	671	671	671
Other renewables	24	24	22	20	43	54	70	115	215	227	239	242	250	240	225	219	222	226	228	236
CHP	102	144	187	176	170	403	402	402	402	402	402	402	402	402	402	402	402	402	402	402
NUG	852	852	754	706	680	606	606	469	421	328	124	124	124	124	65	65	65	65	65	65
CCGT	20	27	13	20	29	124	123	582	1,045	1,328	1,619	1,722	1,193	840	512	429	467	545	568	800
SCGT / Lennox	7	0	0	43	72	72	108	109	116	143	161	162	149	135	124	124	124	124	124	125
Coal	963	954	865	661	398	322	319	0	0	0	0	0	0	0	0	0	0	0	0	0
CDM	369	450	746	590	605	603	616	625	478	469	478	457	442	399	402	393	414	353	505	500
Total	2,814	2,918	3,063	2,798	2,677	3,064	3,269	3,346	3,746	3,998	5,385	6,769	8,042	9,832	10,948	11,580	11,649	11,692	11,872	12,082

Table GRN-A-1: Installed Capacity (MW)
Case GRN-A - Green Base Case

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Nuclear	11,419	11,419	11,379	11,379	12,149	12,403	12,403	11,090	9,726	9,210	7,527	5,832	4,951	3,555	3,555	3,555	3,555	3,555	3,555	3,040
Wind	659	1,447	1,646	2,161	2,345	3,036	3,975	4,280	4,609	4,939	6,758	8,284	9,172	9,946	9,946	9,946	9,946	9,946	9,946	9,946
Hydro	7,843	7,849	7,940	7,986	8,075	8,570	8,700	8,754	8,944	8,957	8,965	9,108	9,967	10,114	10,615	10,615	10,644	10,779	10,779	10,779
Other renewables	241	396	496	496	557	597	640	708	869	882	895	899	946	946	946	946	946	946	946	946
CHP	353	500	736	736	736	1,322	1,322	1,322	1,322	1,322	1,322	1,322	1,322	1,322	1,322	1,322	1,322	1,322	1,322	1,322
NUG	1,517	1,517	1,517	1,512	1,512	1,347	1,347	1,043	936	730	275	275	275	275	144	144	144	144	144	144
CCGT	1,340	4,343	4,943	4,943	4,943	4,943	4,943	4,943	4,943	4,943	4,943	5,443	5,443	5,943	6,943	7,443	8,443	8,443	8,443	8,443
SCGT / Lennox	2,174	2,174	2,174	2,524	2,524	2,524	2,524	2,524	2,524	2,524	2,524	2,524	2,524	2,974	1,924	1,924	1,924	1,924	1,924	1,924
Coal	6,434	6,434	6,434	4,969	3,293	306	306	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	31,980	36,079	37,265	36,706	36,133	35,048	36,161	34,664	33,873	33,507	33,209	33,687	34,601	35,075	35,395	35,895	36,924	37,059	37,059	36,544

Table GRN-A-2: Effective Capacity (MW)
Case GRN-A - Green Base Case

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Nuclear	11,419	11,419	11,379	11,379	12,149	12,403	12,403	11,090	9,726	9,210	7,527	5,832	4,951	3,555	3,555	3,555	3,555	3,555	3,555	3,040
Wind	132	289	329	432	469	607	795	856	922	988	1,412	1,778	1,994	2,188	2,188	2,188	2,188	2,188	2,188	2,188
Hydro	6,039	6,044	6,114	6,149	6,217	6,599	6,699	6,740	6,887	6,897	6,903	7,013	7,675	7,788	8,174	8,174	8,196	8,300	8,300	8,300
Other renewables	241	396	496	496	557	597	640	708	869	882	895	899	946	946	946	946	946	946	946	946
CHP	353	500	736	736	736	1,322	1,322	1,322	1,322	1,322	1,322	1,322	1,322	1,322	1,322	1,322	1,322	1,322	1,322	1,322
NUG	1,517	1,517	1,517	1,512	1,512	1,347	1,347	1,043	936	730	275	275	275	275	144	144	144	144	144	144
CCGT	1,340	4,343	4,943	4,943	4,943	4,943	4,943	4,943	4,943	4,943	4,943	5,443	5,443	5,943	6,943	7,443	8,443	8,443	8,443	8,443
SCGT / Lennox	2,174	2,174	2,174	2,524	2,524	2,524	2,524	2,524	2,524	2,524	2,524	2,524	2,524	2,974	1,924	1,924	1,924	1,924	1,924	1,924
Coal	6,434	6,434	6,434	4,969	3,293	306	306	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	29,649	33,116	34,122	33,141	32,400	30,648	30,979	29,226	28,129	27,496	25,801	25,086	25,130	24,990	25,195	25,695	26,718	26,822	26,822	26,307

Table GRN-A-3: Supply Requirements
Case GRN-A - Green Base Case

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Peak demand	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
Less CDM	-1,006	-1,375	-2,162	-2,773	-3,475	-4,263	-4,971	-5,725	-6,550	-7,560	-8,615	-9,374	-9,959	-9,867	-10,044	-10,142	-10,251	-10,382	-10,523	-10,651
Net peak demand	25,509	25,374	24,824	24,432	23,951	23,385	22,902	22,374	21,907	21,260	20,572	20,185	19,977	20,577	20,916	21,343	21,769	22,181	22,592	23,026
Effective capacity	29,649	33,116	34,122	33,141	32,400	30,648	30,979	29,226	28,129	27,496	25,801	25,086	25,130	24,990	25,195	25,695	26,718	26,822	26,822	26,307
Effective reserve margin	4,140	7,742	9,298	8,709	8,449	7,263	8,077	6,853	6,221	6,236	5,229	4,901	5,153	4,414	4,280	4,352	4,948	4,641	4,230	3,280
% Reserves	16%	31%	37%	36%	35%	31%	35%	31%	28%	29%	25%	24%	26%	21%	20%	20%	23%	21%	19%	14%

Table GRN-A-4: Generation (TWh)
Case GRN-A - Green Base Case

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Nuclear	81	79	78	81	88	90	89	81	69	66	54	42	35	26	25	26	26	25	26	22
Wind	2	4	4	5	6	8	10	11	11	12	18	23	25	28	28	28	28	28	28	28
Hydro	43	42	42	41	38	35	34	36	40	41	44	47	49	51	53	53	53	54	54	54
Other renewables	1	1	1	1	1	1	0	1	1	1	2	2	3	3	3	3	3	4	4	4
CHP	2	3	4	4	4	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
NUG	9	9	9	9	9	8	8	6	5	4	2	2	2	2	1	1	1	1	1	1
CCGT	0	0	10	6	2	0	0	1	2	2	4	7	7	15	16	18	20	22	24	31
SCGT / Lennox	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Coal	17	16	3	2	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	154	154	151	149	149	150	149	143	137	134	131	129	129	132	134	136	139	142	144	147

Table GRN-A-5: Capacity Factor (%)
Case GRN-A - Green Base Case

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Nuclear	81%	79%	78%	82%	83%	83%	82%	83%	81%	82%	82%	81%	81%	82%	82%	82%	82%	82%	83%	82%
Wind	28%	28%	28%	28%	28%	28%	28%	28%	28%	28%	30%	31%	32%	32%	32%	32%	32%	32%	32%	32%
Hydro	62%	62%	60%	58%	54%	47%	45%	47%	51%	52%	56%	58%	56%	57%	57%	57%	57%	57%	57%	57%
Other renewables	27%	21%	18%	17%	15%	10%	9%	9%	15%	16%	24%	31%	32%	40%	40%	41%	42%	43%	43%	44%
CHP	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%
NUG	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%
CCGT	2%	1%	24%	14%	5%	1%	1%	1%	4%	4%	9%	14%	14%	28%	26%	28%	27%	30%	33%	41%
SCGT / Lennox	0%	0%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%
Coal	30%	29%	4%	5%	2%	6%	3%													
Total	55%	49%	46%	46%	47%	49%	47%	47%	46%	46%	45%	44%	42%	43%	43%	43%	43%	44%	44%	46%

Table GRN-A-6: Annual Costs (million C$)
Case GRN-A - Green Base Case

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Nuclear	469	458	453	471	511	524	514	470	403	382	312	241	205	148	148	148	149	148	149	127
Wind	0	0	0	123	169	329	550	620	696	770	1,333	1,821	2,109	2,369	2,364	2,359	2,354	2,350	2,345	2,341
Hydro	8	9	22	36	58	152	186	200	244	248	250	284	482	515	631	631	640	671	671	671
Other renewables	25	25	22	18	38	43	57	93	186	193	212	227	247	262	262	264	266	267	268	269
CHP	166	235	306	287	277	596	595	595	595	595	595	595	595	595	595	595	595	595	595	595
NUG	741	741	656	614	591	526	526	408	366	285	107	107	107	107	56	56	56	56	56	56
CCGT	16	18	799	437	156	30	17	43	113	118	269	540	536	1,153	1,340	1,544	1,801	1,953	2,106	2,546
SCGT / Lennox	4	0	23	47	43	43	43	43	43	43	44	44	44	138	122	122	120	121	123	130
Coal	961	942	315	251	145	25	23	0	0	0	0	0	0	0	0	0	0	0	0	0
CDM	283	424	1,731	1,252	1,431	1,440	1,449	1,458	1,484	1,493	1,524	1,548	1,555	1,572	1,599	1,625	1,652	1,670	1,696	1,723
Total	2,671	2,852	4,328	3,535	3,419	3,707	3,959	3,929	4,129	4,126	4,647	5,408	5,879	6,858	7,117	7,344	7,632	7,829	8,009	8,456

Table GRN-B-1: Installed Capacity (MW)
Case GRN-B - Green Increased Peaking Case

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Nuclear	11,419	11,419	11,379	11,379	12,149	12,403	12,403	11,090	9,726	9,210	7,527	5,832	4,951	3,555	3,555	3,555	3,555	3,555	3,555	3,040
Wind	659	1,447	1,646	2,161	2,345	3,036	3,975	4,280	4,609	4,939	6,758	8,284	9,172	9,946	9,946	9,946	9,946	9,946	9,946	9,946
Hydro	7,843	7,849	7,940	7,986	8,075	8,570	8,700	8,754	8,944	8,957	8,965	9,108	9,967	10,114	10,615	10,615	10,644	10,779	10,779	10,779
Other renewables	241	396	496	496	557	597	640	708	869	882	895	899	946	946	946	946	946	946	946	946
CHP	353	500	736	736	736	1,322	1,322	1,322	1,322	1,322	1,322	1,322	1,322	1,322	1,322	1,322	1,322	1,322	1,322	1,322
NUG	1,517	1,517	1,517	1,512	1,512	1,347	1,347	1,043	936	730	275	275	275	275	144	144	144	144	144	144
CCGT	1,340	4,343	4,943	4,943	4,943	4,943	4,943	4,943	4,943	4,943	4,943	4,943	4,943	4,943	4,943	4,943	4,943	4,943	4,943	4,943
SCGT / Lennox	2,174	2,174	2,174	2,524	2,974	2,974	2,974	2,974	2,974	2,974	2,974	3,024	3,024	3,974	3,924	4,424	5,424	5,424	5,424	5,424
Coal	6,434	6,434	6,434	4,969	3,293	306	306	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	31,980	36,079	37,265	36,706	36,583	35,498	36,611	35,114	34,323	33,957	33,659	33,687	34,601	35,075	35,395	35,895	36,924	37,059	37,059	36,544

Table GRN-B-2: Effective Capacity (MW)
Case GRN-B - Green Increased Peaking Case

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Nuclear	11,419	11,419	11,379	11,379	12,149	12,403	12,403	11,090	9,726	9,210	7,527	5,832	4,951	3,555	3,555	3,555	3,555	3,555	3,555	3,040
Wind	132	289	329	432	469	607	795	856	922	988	1,412	1,778	1,994	2,188	2,188	2,188	2,188	2,188	2,188	2,188
Hydro	6,039	6,044	6,114	6,149	6,217	6,599	6,699	6,740	6,887	6,897	6,903	7,013	7,675	7,788	8,174	8,174	8,196	8,300	8,300	8,300
Other renewables	241	396	496	496	557	597	640	708	869	882	895	899	946	946	946	946	946	946	946	946
CHP	353	500	736	736	736	1,322	1,322	1,322	1,322	1,322	1,322	1,322	1,322	1,322	1,322	1,322	1,322	1,322	1,322	1,322
NUG	1,517	1,517	1,517	1,512	1,512	1,347	1,347	1,043	936	730	275	275	275	275	144	144	144	144	144	144
CCGT	1,340	4,343	4,943	4,943	4,943	4,943	4,943	4,943	4,943	4,943	4,943	4,943	4,943	4,943	4,943	4,943	4,943	4,943	4,943	4,943
SCGT / Lennox	2,174	2,174	2,174	2,524	2,974	2,974	2,974	2,974	2,974	2,974	2,974	3,024	3,024	3,974	3,924	4,424	5,424	5,424	5,424	5,424
Coal	6,434	6,434	6,434	4,969	3,293	306	306	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	29,649	33,116	34,122	33,141	32,850	31,098	31,429	29,676	28,579	27,946	26,251	25,086	25,130	24,990	25,195	25,695	26,718	26,822	26,822	26,307

Table GRN-B-3: Supply Requirements
Case GRN-B - Green Increased Peaking Case

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Peak demand	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
Less CDM	-1,006	-1,375	-2,162	-2,773	-3,475	-4,263	-4,971	-5,725	-6,550	-7,560	-8,615	-9,374	-9,959	-9,867	-10,044	-10,142	-10,251	-10,382	-10,523	-10,651
Net peak demand	25,509	25,374	24,824	24,432	23,951	23,385	22,902	22,374	21,907	21,260	20,572	20,185	19,977	20,577	20,916	21,343	21,769	22,181	22,592	23,026
Effective capacity	29,649	33,116	34,122	33,141	32,850	31,098	31,429	29,676	28,579	27,946	26,251	25,086	25,130	24,990	25,195	25,695	26,718	26,822	26,822	26,307
Effective reserve margin	4,140	7,742	9,298	8,709	8,899	7,713	8,527	7,303	6,671	6,686	5,679	4,901	5,153	4,414	4,280	4,352	4,948	4,641	4,230	3,280
% Reserves	16%	31%	37%	36%	37%	33%	37%	33%	30%	31%	28%	24%	26%	21%	20%	20%	23%	21%	19%	14%

Table GRN-B-4: Generation (TWh)
Case GRN-B - Green Increased Peaking Case

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Nuclear	81	79	78	81	88	90	89	81	69	66	54	42	35	26	25	26	26	25	26	22
Wind	2	4	4	5	6	8	10	11	11	12	18	23	25	28	28	28	28	28	28	28
Hydro	43	42	42	41	38	35	34	36	40	41	44	47	49	51	53	53	53	54	54	54
Other renewables	1	1	1	1	1	1	0	1	1	1	2	2	3	3	3	3	3	4	4	4
CHP	2	3	4	4	4	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
NUG	9	9	9	9	9	8	8	6	5	4	2	2	2	2	1	1	1	1	1	1
CCGT	0	0	10	6	2	0	0	1	2	2	4	7	7	15	16	18	19	21	23	28
SCGT / Lennox	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1	1	2
Coal	17	16	3	2	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	154	154	151	149	149	150	149	143	137	134	131	129	129	132	134	136	139	142	144	147

Table GRN-B-5: Capacity Factor (%)
Case GRN-B - Green Increased Peaking Case

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Nuclear	81%	79%	78%	82%	83%	83%	82%	83%	81%	82%	82%	81%	81%	82%	82%	82%	82%	82%	83%	82%
Wind	28%	28%	28%	28%	28%	28%	28%	28%	28%	28%	30%	31%	32%	32%	32%	32%	32%	32%	32%	32%
Hydro	62%	62%	60%	58%	54%	47%	45%	47%	51%	52%	56%	58%	56%	57%	57%	57%	57%	57%	57%	57%
Other renewables	27%	21%	18%	17%	15%	10%	9%	9%	15%	16%	24%	31%	32%	40%	40%	41%	42%	43%	43%	44%
CHP	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%
NUG	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%
CCGT	2%	1%	24%	14%	5%	1%	1%	1%	4%	4%	9%	16%	16%	34%	36%	40%	45%	49%	54%	65%
SCGT / Lennox	0%	0%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	1%	1%	1%	2%	2%	5%
Coal	30%	29%	4%	5%	2%	6%	3%													
Total	55%	49%	46%	46%	46%	48%	46%	46%	45%	45%	44%	44%	42%	43%	43%	43%	43%	44%	44%	46%

Table GRN-B-6: Annual Costs (million C$)
Case GRN-B - Green Increased Peaking Case

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Nuclear	469	458	453	471	511	524	514	470	403	382	312	241	205	148	148	148	149	148	149	127
Wind	0	0	0	123	169	329	550	620	696	770	1,333	1,821	2,109	2,369	2,364	2,359	2,354	2,350	2,345	2,341
Hydro	8	9	22	36	58	152	186	200	244	248	250	284	482	515	631	631	640	671	671	671
Other renewables	25	25	22	18	38	43	57	93	186	193	212	227	247	262	262	264	266	267	268	269
CHP	166	235	306	287	277	596	595	595	595	595	595	595	595	595	595	595	595	595	595	595
NUG	741	741	656	614	591	526	526	408	366	285	107	107	107	107	56	56	56	56	56	56
CCGT	16	18	799	437	156	30	17	43	113	118	269	485	480	1,034	1,104	1,245	1,380	1,519	1,654	2,001
SCGT / Lennox	4	0	23	47	72	72	72	72	72	72	73	78	78	217	277	322	403	422	450	582
Coal	961	942	315	251	145	25	23	0	0	0	0	0	0	0	0	0	0	0	0	0
CDM	283	424	1,731	1,252	1,431	1,440	1,449	1,458	1,484	1,493	1,524	1,548	1,555	1,572	1,599	1,625	1,652	1,670	1,696	1,723
Total	2,671	2,852	4,328	3,535	3,448	3,736	3,989	3,958	4,158	4,155	4,676	5,386	5,858	6,819	7,037	7,246	7,495	7,697	7,884	8,363

Table GRN-C-1: Installed Capacity (MW)
Case GRN-C - Green Aggressive CDM

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Nuclear	11,419	11,419	11,379	11,379	12,149	12,403	12,403	11,090	9,726	9,210	7,527	5,832	4,951	3,555	3,555	3,555	3,555	3,555	3,555	3,040
Wind	659	1,447	1,646	2,161	2,345	3,036	3,975	4,280	4,609	4,939	6,758	8,284	9,172	9,946	9,946	9,946	9,946	9,946	9,946	9,946
Hydro	7,843	7,849	7,940	7,986	8,075	8,570	8,700	8,754	8,944	8,957	8,965	9,108	9,967	10,114	10,615	10,615	10,644	10,779	10,779	10,779
Other renewables	241	396	496	496	557	597	640	708	869	882	895	899	946	946	946	946	946	946	946	946
CHP	353	500	736	736	736	1,322	1,322	1,322	1,322	1,322	1,322	1,322	1,322	1,322	1,322	1,322	1,322	1,322	1,322	1,322
NUG	1,517	1,517	1,517	1,512	1,512	1,347	1,347	1,043	936	730	275	275	275	275	144	144	144	144	144	144
CCGT	1,340	4,343	4,943	4,943	4,943	4,943	4,943	4,943	4,943	4,943	4,943	4,943	4,943	4,943	5,443	5,443	6,443	6,443	6,443	6,443
SCGT / Lennox	2,174	2,174	2,174	2,524	2,524	2,524	2,524	2,524	2,524	2,524	2,524	2,524	2,524	2,974	1,924	1,924	1,924	1,924	1,924	1,924
Coal	6,434	6,434	6,434	4,969	3,293	306	306	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	31,980	36,079	37,265	36,706	36,133	35,048	36,161	34,664	33,873	33,507	33,209	33,187	34,101	34,075	33,895	33,895	34,924	35,059	35,059	34,544

Table GRN-C-2: Effective Capacity (MW)
Case GRN-C - Green Aggressive CDM

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Nuclear	11,419	11,419	11,379	11,379	12,149	12,403	12,403	11,090	9,726	9,210	7,527	5,832	4,951	3,555	3,555	3,555	3,555	3,555	3,555	3,040
Wind	132	289	329	432	469	607	795	856	922	988	1,412	1,778	1,994	2,188	2,188	2,188	2,188	2,188	2,188	2,188
Hydro	6,039	6,044	6,114	6,149	6,217	6,599	6,699	6,740	6,887	6,897	6,903	7,013	7,675	7,788	8,174	8,174	8,196	8,300	8,300	8,300
Other renewables	241	396	496	496	557	597	640	708	869	882	895	899	946	946	946	946	946	946	946	946
CHP	353	500	736	736	736	1,322	1,322	1,322	1,322	1,322	1,322	1,322	1,322	1,322	1,322	1,322	1,322	1,322	1,322	1,322
NUG	1,517	1,517	1,517	1,512	1,512	1,347	1,347	1,043	936	730	275	275	275	275	144	144	144	144	144	144
CCGT	1,340	4,343	4,943	4,943	4,943	4,943	4,943	4,943	4,943	4,943	4,943	4,943	4,943	4,943	5,443	5,443	6,443	6,443	6,443	6,443
SCGT / Lennox	2,174	2,174	2,174	2,524	2,524	2,524	2,524	2,524	2,524	2,524	2,524	2,524	2,524	2,974	1,924	1,924	1,924	1,924	1,924	1,924
Coal	6,434	6,434	6,434	4,969	3,293	306	306	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	29,649	33,116	34,122	33,141	32,400	30,648	30,979	29,226	28,129	27,496	25,801	24,586	24,630	23,990	23,695	23,695	24,718	24,822	24,822	24,307

Table GRN-C-3: Supply Requirements
Case GRN-C - Green Aggressive CDM

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Peak demand	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
Less CDM	-1,006	-1,375	-2,162	-2,773	-3,475	-4,295	-5,059	-5,904	-6,860	-8,073	-9,838	-10,283	-11,029	-11,118	-11,458	-11,717	-11,967	-12,228	-12,467	-12,652
Net peak demand	25,509	25,374	24,824	24,432	23,951	23,353	22,814	22,195	21,597	20,747	19,349	19,276	18,907	19,326	19,502	19,768	20,053	20,335	20,648	21,025
Effective capacity	29,649	33,116	34,122	33,141	32,400	30,648	30,979	29,226	28,129	27,496	25,301	24,586	24,630	23,990	23,595	23,695	24,718	24,822	24,822	24,307
Effective reserve margin	4,140	7,742	9,298	8,709	8,449	7,295	8,166	7,031	6,532	6,749	5,952	5,310	5,723	4,664	4,093	3,928	4,665	4,487	4,173	3,281
% Reserves	16%	31%	37%	36%	35%	31%	36%	32%	30%	33%	31%	28%	30%	24%	21%	20%	23%	22%	20%	16%

Table GRN-C-4: Generation (TWh)
Case GRN-C - Green Aggressive CDM

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Nuclear	81	79	78	81	88	90	89	81	69	66	54	42	35	26	25	26	26	25	26	22
Wind	2	4	4	5	6	8	10	11	11	12	18	23	25	28	28	28	28	28	28	28
Hydro	43	42	42	41	38	35	34	35	39	40	43	45	47	50	52	52	52	53	53	54
Other renewables	1	1	1	1	1	1	0	1	1	1	2	2	2	3	3	3	3	3	3	4
CHP	2	3	4	4	4	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
NUG	9	9	9	9	9	8	8	6	5	4	2	2	2	2	1	1	1	1	1	1
CCGT	0	0	10	6	2	0	0	1	1	1	2	4	4	10	10	11	13	14	16	21
SCGT / Lennox	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Coal	17	16	3	2	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	154	154	151	149	149	150	149	142	136	132	128	125	124	126	127	129	131	133	135	137

Table GRN-C-5: Capacity Factor (%)
Case GRN-C - Green Aggressive CDM

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Nuclear	81%	79%	78%	82%	83%	83%	82%	83%	81%	82%	82%	81%	81%	82%	82%	82%	82%	82%	83%	82%
Wind	28%	28%	28%	28%	28%	28%	28%	28%	28%	28%	30%	31%	32%	32%	32%	32%	32%	32%	32%	32%
Hydro	62%	62%	60%	58%	54%	47%	45%	46%	50%	50%	55%	57%	54%	57%	56%	56%	56%	56%	56%	57%
Other renewables	27%	21%	18%	17%	15%	10%	9%	9%	14%	13%	20%	27%	27%	38%	38%	39%	39%	40%	41%	43%
CHP	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%
NUG	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%	67%
CCGT	2%	1%	24%	14%	5%	1%	1%	1%	3%	2%	5%	9%	9%	23%	21%	24%	22%	25%	28%	38%
SCGT / Lennox	0%	0%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%
Coal	30%	29%	4%	5%	2%	5%	3%													
Total	55%	49%	46%	46%	47%	49%	47%	47%	46%	45%	44%	43%	41%	42%	43%	43%	43%	43%	44%	45%

Table GRN-C-6: Annual Costs (million C$)
Case GRN-C - Green Aggressive CDM

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Nuclear	469	458	453	471	511	524	514	470	403	382	312	241	205	148	148	148	149	148	149	127
Wind	0	0	0	123	169	329	550	620	696	770	1,333	1,821	2,109	2,369	2,364	2,359	2,354	2,350	2,345	2,341
Hydro	8	9	22	36	58	152	186	200	244	248	250	284	482	515	631	631	640	671	671	671
Other renewables	25	25	22	18	38	43	57	92	183	187	204	219	237	257	257	259	260	262	263	267
CHP	166	235	306	287	277	596	595	595	595	595	595	595	595	595	595	595	595	595	595	595
NUG	741	741	656	614	591	526	526	408	366	285	107	107	107	107	56	56	56	56	56	56
CCGT	16	18	799	437	156	29	16	36	84	71	154	292	264	697	774	858	1,058	1,156	1,269	1,665
SCGT / Lennox	4	0	23	47	43	43	43	43	43	43	43	43	43	135	123	124	121	122	123	131
Coal	961	942	315	251	145	25	23	0	0	0	0	0	0	0	0	0	0	0	0	0
CDM	283	424	1,731	1,252	1,431	1,498	1,565	1,633	1,722	1,792	1,829	1,858	1,866	1,887	1,919	1,951	1,982	2,004	2,035	2,067
Total	2,671	2,852	4,328	3,535	3,419	3,764	4,074	4,097	4,334	4,372	4,828	5,460	5,907	6,711	6,866	6,981	7,215	7,362	7,507	7,918