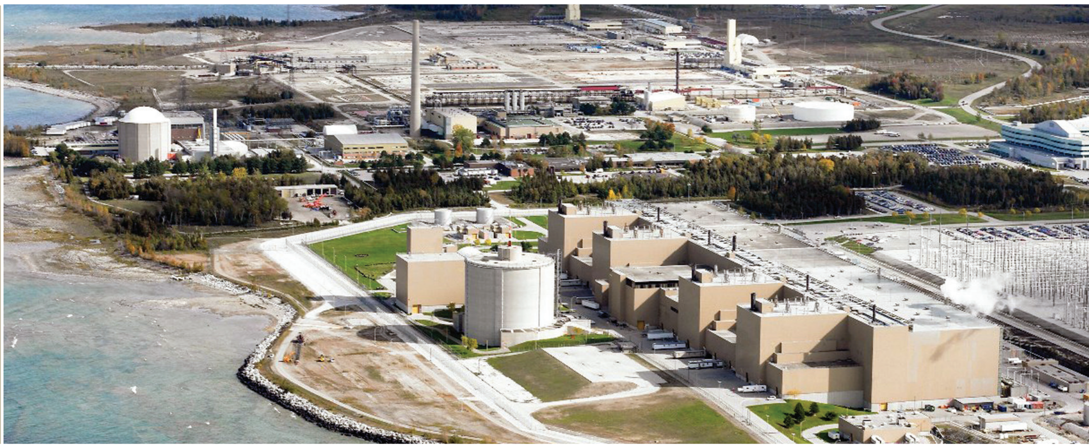
Special Review for the Minister of Energy

The Bruce Power Refurbishment Agreement



Office of the Auditor General of Ontario

Office of the Auditor General of Ontario

To the Honourable Dwight Duncan
Minister of Energy

I am pleased to transmit my report on a special review of the Bruce Power Refurbishment Agreement, which was requested by the former Minister of Energy pursuant to Section 17 of the *Auditor General Act*.

It is my understanding that you will be publicly releasing the report on or before Wednesday, April 11, 2007, which is when my Office will be ready to issue both English and French versions of this report. I also understand that if you release the report before that date, your Ministry will undertake the responsibility of making copies of the report immediately available to Members of the Legislative Assembly, the media, and the public.

Jim McCarter
Auditor General

April 5, 2007

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Cover photograph provided by Bruce Power

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Background

THE BRUCE NUCLEAR FACILITY

The Bruce nuclear facility, located on the eastern shore of Lake Huron, was constructed in stages between 1970 and 1987 by what was then Ontario Hydro, a provincial Crown corporation. The facility consists of two power plants—A and B—and is one of the largest nuclear generating facilities in North America. Each plant hosts four CANDU reactor units, with a maximum net generating capacity permitted by their licences of over 6,200 megawatts (MW) of electrical power—a net capacity of 769 MW/unit for A and a net capacity of 785 MW/unit for B. In the late 1990s, Ontario Hydro made a business decision to shut down the four units of Bruce A in order to concentrate resources on its other reactors, leaving only the B units to produce electricity.

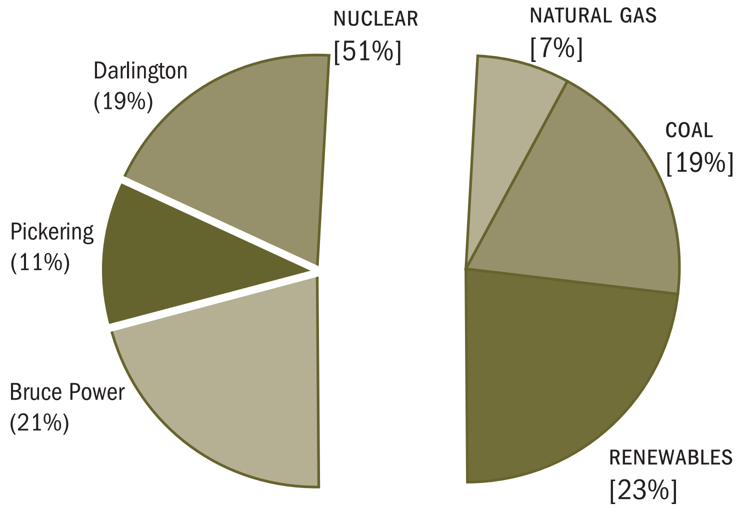
In 1999, as part of the government's restructuring plan at that time, Ontario Hydro was split into five component Crown corporations: Ontario Power Generation (OPG), the Ontario Hydro Services Company (now Hydro One Inc.), the Independent Electricity Market Operator (called the Independent Electricity System Operator since 2004), the Electrical Safety Authority, and Ontario Electricity Financial Corporation. Of these five component corporations, OPG was the one that took over all electrical generating stations. In 2001, OPG entered into a long-term lease agreement with the Bruce Power Limited Partnership (Bruce Power)—a private-sector partnership made up of British Energy PLC (79.8%); the Cameco Corporation, a private-sector uranium producer (15%); and the facility's two primary unions (5.2%)—to take over operation of the Bruce facility. The lease is for a period of 18 years, expiring in December 2018, with options for 13 extensions for up to an additional 25 years.

Financial concerns involving its operations outside of Canada led British Energy PLC to withdraw from Bruce Power in 2003. As a result, the Cameco Corporation increased its share of Bruce Power to 31.6%, while new partners TransCanada PipeLines and BPC Generation Infrastructure Trust (a trust owned by the Ontario Municipal Employees Retirement System [OMERS]) each acquired a 31.6% share. The facility's two primary unions retained their original 5.2% share.

Bruce Power has been operating Bruce B's four units since 2001 and invested $720 million to restart Units 3 and 4 of Bruce A in 2003 and 2004.

Figure 1: Ontario's Electricity Production by Fuel Source and Nuclear Power Plant, July 2005

Sources of data: Ontario Power Authority and the Independent Electricity System Operator



As Figure 1 shows, the total energy produced by Bruce A Units 3 and 4 and the four units of Bruce B constitutes about 21% of the province's total actual electricity production.

THE 2005 REFURBISHMENT AGREEMENT

In summer 2004, Bruce Power approached the province with a financial proposition to refurbish and restart Units 1 and 2 of Bruce A, which, once refurbished and operational, could meet about 7% of Ontario's energy needs. The proposition also gave the province an alternative to OPG refurbishment projects, in which electricity ratepayers directly assume the risks associated with refurbishment.

After extensive negotiations, the Minister of Energy announced on October 17, 2005, that the government and Bruce Power had reached an agreement, titled the Bruce Power Refurbishment Implementation Agreement (Refurbishment Agreement).

Cameco Corporation, one of the partners in Bruce Power, had decided not to participate in the refurbishment. A separate partnership, called Bruce A Limited Partnership (Bruce A LP), was formed, to not only refurbish Units 1 and 2 but also take over Cameco's interest in Units 3 and 4 and make future improvements to them. Bruce A LP would thus ultimately be operating and maintaining all four Bruce A units. Bruce A LP's owners are TransCanada PipeLines (47.4%), OMERS (47.4%), and the facility's two primary unions (5.2%).

With regard to the refurbishment, Bruce A LP is expected to invest $4.25 billion to:

- refurbish and restart Units 1 and 2—at a projected cost of $2.75 billion—for 25 years of additional production life (creating 1,500 MW of electrical capacity);
- refurbish Unit 3—at a projected cost of $1.15 billion—when it reaches the end of its operational life in around 2009 (again for 25 years of additional production life); and
- replace the steam generator in Unit 4 in 2007 at an estimated cost of $350 million (for 10 years of production life).

In return, the province, through the Ontario Power Authority (OPA) (a corporation created in 2004 under the *Electricity Act, 1998*, to ensure an adequate long-term supply of electricity in Ontario), agreed to:

- an initial price for electricity of 6.3¢/KWh ($63/MWh) as of the date the Refurbishment Agreement was signed, comprising:
  - 5.737¢/KWh ($57.37/MWh) for the purchase of power produced by Bruce A LP; and
  - an estimated 0.6¢/KWh ($6/MWh) to cover the cost of fuel.

This price will be escalated annually by an agreed-upon factor based on increases in the Consumer Price Index. Consequently, the price will have increased by the time the refurbished units become operational.

Review Scope and Objective

After the Refurbishment Agreement was signed, the Minister of Energy announced she would be requesting, under the provision of section 17 of the *Auditor General Act*, that the Office of the Auditor General review any and all aspects of the transaction. The Minister indicated when making her request that the terms of the Refurbishment Agreement had already been subject to detailed due diligence—conducted with assistance from expert financial, legal, and technical advisers engaged by the government—and had been approved by the Ontario Cabinet.

We accepted this assignment and advised the Deputy Minister of Energy of the objective of our review, as follows:

> Our primary focus will be to assess whether the province's processes were sufficient to ensure all significant risks and issues were properly considered and addressed and that complete and objective information was available to the decision-makers who were responsible for ensuring the agreement represented good value for Ontario taxpayers. While we will take into consideration the due diligence performed by the government and its external consultants, repeating the due diligence work will not be the focus of our review.

This assignment was a review engagement and not an audit. Accordingly, it consisted of reviewing and analyzing information provided by the Ministry of Energy and its advisers, as well as discussing relevant matters with staff from the ministries of Energy and Finance. We also had a number of meetings with the technical and financial consultants engaged by the Ministry of Energy and representatives of Bruce A LP, OPG, the OPA, and the Canadian Nuclear Safety Commission. In addition, we engaged the services of independent consultants who are experts in business valuation and nuclear engineering to assist in certain aspects of our review.

Our work was largely completed by July 2006, except for the review of certain information received in late 2006 and early 2007 relating to settlements between Bruce A LP and the OPA. This information was maintained by the OPA, and our enabling legislation, the *Auditor General Act*, did not allow us access to it at the time we were conducting our review. Subsequently, in December 2006, a bill was passed that allowed us access.

Summary

When the province began negotiating an agreement with Bruce A LP for refurbishing the Bruce A nuclear units, the province's existing nuclear facilities were aging and nearing the end of their operating life. At the same time, demand for electricity was increasing due to population and economic growth. These factors, along with the government's announcements that it intended to phase out all the province's coal-burning generating plants over time, meant that, at the time of the negotiations, the province needed to bring on substantial new power-generation capacity, especially given the long lead time needed for major electricity construction projects. All of these factors made it difficult for the province to negotiate from a position of strength. Nevertheless, the province made considerable efforts to ensure that it had the technical, financial, and legal expertise it needed to negotiate an extremely complex agreement. It also followed processes designed to ensure that complete and objective information was available to the province's negotiators.

Entering into the negotiations, the province had two important objectives to meet: first, it wanted to ensure that appropriate operating and construction-cost risks associated with the refurbishment would be transferred to Bruce A LP and away from ratepayers; second, it wanted to ensure that the price to be paid for the electricity produced by the refurbished units was reasonable relative to historical and expected market prices for electricity and prices for other comparable supply alternatives.

Bruce A LP's key objective in the negotiations was ensuring that it obtain a rate of return on its investment that would be commensurate with the risk it was assuming. The province had its external financial advisers assess the rate of return that Bruce A LP had targeted, and they concluded that it was within an acceptable range, given the nature and risk of the refurbishment project. The terms of the signed Refurbishment Agreement provide Bruce A LP with projected cash flows that will enable it to meet its targeted rate-of-return requirement if it meets operating performance targets.

As for the province's first objective of risk transfer, provisions were negotiated that successfully transferred most of the ongoing operating risks to Bruce A LP; however, the province was only partially successful in transferring the risks relating to construction-cost overruns. We had three concerns in this regard.

First, the province did not obtain sufficient evidence to justify a late $250-million increase in estimated costs, raising the total-cost estimate from $2.5 billion to $2.75 billion. Second, it is the ratepayer, as opposed to Bruce A LP, that assumes the risk of paying for most of this $250-million increase in the estimated cost—even if the increase does not materialize. We do acknowledge, on the other hand, that the province was successful in transferring much of the risk to Bruce A LP if costs exceed $3.05 billion—Bruce A LP will be responsible for funding 75% of Unit 1 and 2 refurbishment costs over this amount. Although both Bruce A LP's and the province's expert advisers concluded that the risk of total costs exceeding $2.8 billion was small—that risk having been mitigated by the use of fixed-price contracts for a majority of the refurbishment costs—cost overruns on previous nuclear projects have been known to rise to over double the originally estimated costs. Our third concern is that the ratepayer is required under the Refurbishment Agreement to share in paying for any overrun on the cost of steam generators to be purchased for Unit 4 of the Bruce A plant. We questioned the appropriateness of involving the ratepayer in this risk, given that Bruce Power had planned to purchase these steam generators months before it approached the province with its refurbishment proposal.

The province's success with respect to its second objective—negotiating a reasonable price for the electricity from the refurbished units—is not clearcut. In order for the province to obtain an initial support price of 6.3¢/KWh ($63/MWh) and Bruce A LP to obtain its targeted rate of return, the province negotiated certain trade-offs that provide Bruce A LP with cash flows to replace the cash flows it would have received if the initial price had been higher. Some of these trade-offs involved making changes to previously agreed-to terms and conditions relating to other Bruce units not involved in the refurbishment. These trade-offs, by our estimate, will result in an all-in initial cost for the electricity from the refurbished units that is closer to 7.1¢/KWh ($71.33/MWh).

On the one hand, this initial price is significantly higher than the average market price in the past five years of 4.9¢/KWh ($49/MWh) and experts' projections of future market prices. On the other hand, it is reasonable to expect that higher prices will be necessary to obtain private-sector investments in new electricity supply over the long term, especially when this involvement includes the private-sector operator taking on most of the ongoing operating risks over the 25-year life of the nuclear units as well as sharing the risks relating to construction-cost overruns.

Aside from these considerations involving the "traded-off" price, we identified other items that had the potential, if they had been handled differently, to reduce the support price by about 0.36¢/KWh ($3.60/MWh), with Bruce A LP still obtaining its targeted rate of return if it meets operating performance targets. The items ranged widely, including a provision relating to the province paying for the lay-up costs of Bruce B units, financial benefits arising from the use of enriched fuel, financial benefits arising from higher electricity output in the early years of the term of the agreement as compared to the later years, savings arising from not having to pay lay-up costs for the units to be refurbished, and a mechanical error in the calculation of tax on interest expenses.

It is also important to note that the initial support price was for 2005 and will be adjusted annually for inflation starting in 2006 by a factor based on the Consumer Price Index (CPI): it will be increased by 100% of the percentage change in CPI up to 2.5%, plus 60% of any inflation above 2.5%. In comparison, the annual CPI-based increases included in the province's agreements with other private-sector, non-nuclear electricity suppliers have been in the 15%-to-20% range. While the appropriate inflationary adjustment is unique to each type of facility, the higher the percentage of CPI increase allowed, the lower the initial support price can be. Allowing 100% of a CPI increase up to 2.5% in the Refurbishment Agreement trades off lower prices in the earlier years for higher prices in later years. All told, it is the combination of this provision, the trade-offs mentioned above, and, in addition, factoring in an inflation-escalation adjustment of 3.5% per year for labour costs and 2.5% per year for all remaining capital and operating costs over the 25-year life of the refurbished units that is expected to provide Bruce A LP with its targeted rate of return at the agreed-upon initial support price.

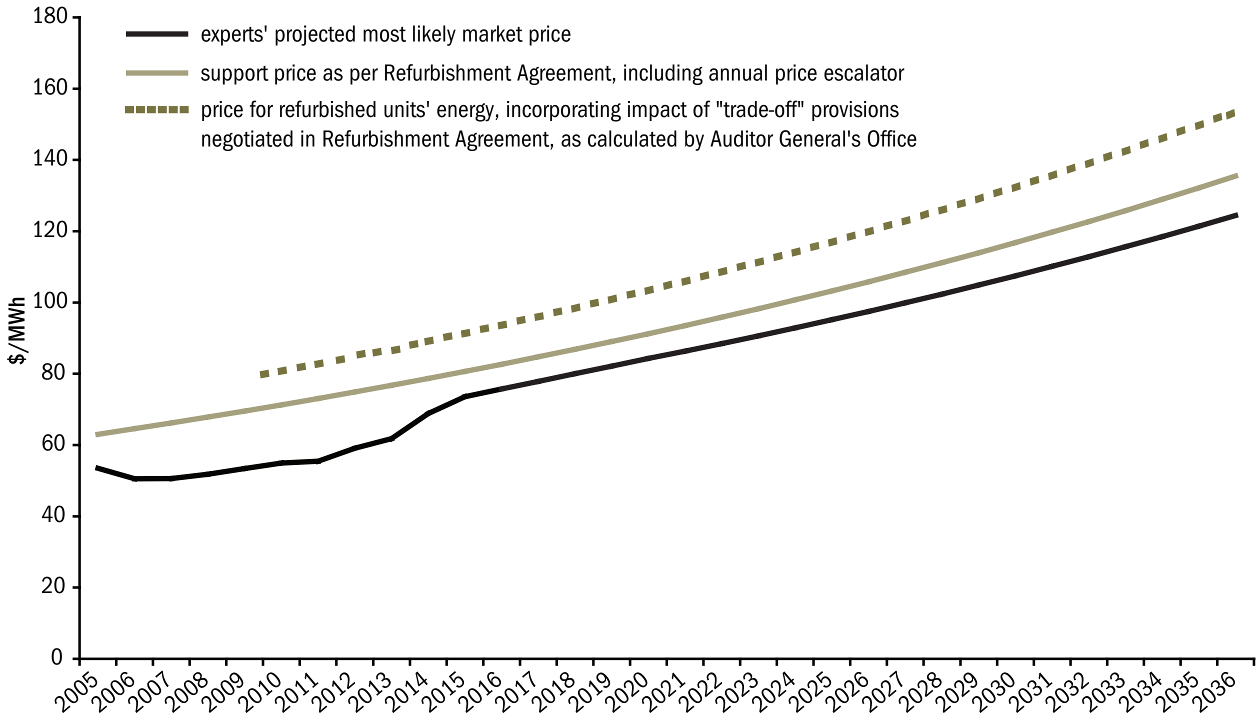
Figure 2 shows the rise in the support price over the term of the Refurbishment Agreement as a result of the annual CPI-based price escalator. It also illustrates the effect if the value of the trade-offs negotiated by the province mentioned above is incorporated into the support price and includes, for comparison purposes, the market price projected by experts to be most likely.

The Detailed Observations of our review are structured as follows:

- The first three sections provide details on the energy situation in Ontario leading up to the negotiations, describe the negotiation process, and present further information relating to Bruce A LP's rate of return (**Ontario's Energy Landscape in 2004 and 2005; The Negotiation Process; Bruce A LP's Return on Investment**).
- The following section is a detailed discussion of the aforementioned trade-offs and CPI-based annual inflation adjustment that helped enable the negotiators to agree upon the initial support price of 6.3¢/KWh ($63/MWh) (**Provisions Lowering the Initial Support Price**).
- This is followed by an analysis of the items referred to above that could have been handled differently, with the result that the

Figure 2: The Price of Electricity over the Long Term

Prepared by the Office of the Auditor General of Ontario



Notes:

From 2005 to 2009, the support price applies only to the electricity supplied by the currently operating Units 3 and 4. From 2009, when the refurbishment is expected to be completed, it also applies to the electricity supplied by Units 1 and 2.

The points plotted on this graph are in nominal dollars for the corresponding years (that is, the amounts are adjusted for inflation). They therefore do not provide a basis for calculations or extrapolations that assume present-value dollars.

support price could have been about 0.36¢/KWh ($3.60/MWh) lower with Bruce A LP still obtaining its required rate of return (**Items That Could Have Reduced the Support Price**).

- The last section in our Detailed Observations is a more detailed analysis of how risks relating to cost overruns are shared under the Refurbishment Agreement (**Responsibility for Cost Overruns**).

In Other Matter, we discuss the risk of transmission capacity not being adequate for the additional electricity produced by Bruce A LP (**Transmission Capacity**).

In the Appendix, we explain the factors we considered in quantifying what the financial impact would have been if the issues we identified in the section Items Could Have Reduced the Support Price had been handled differently.

Detailed Observations

ONTARIO'S ENERGY LANDSCAPE IN 2004 AND 2005

Nuclear energy produces about half of the electricity generated in Ontario, providing it as "baseload" power. Baseload resources, such as water- and nuclear-generated energy, are normally run continuously at full power day and night to produce lower-cost electricity. Intermediate- and peak-load resources, such as natural gas and petroleum, are usually used during peak periods for shorter periods of time.

While Ontario's existing nuclear facilities have been aging and nearing the end of their operating life, demand for electricity has been increasing due to population and economic growth. These factors, along with the government's announcements that it intended to phase out all the province's coal-burning generating plants over time, meant that, at the time of the negotiations, the province needed to bring on substantial new power-generation capacity, especially given the long lead time needed for major electricity construction projects. Specifically, the OPA estimated that the province would need to develop new electricity generation sources for 3,500 MW annually, or about 20% of Ontario's electricity over the next three years.

Subsequent to the government's announcement, Bruce Power approached the province and expressed its willingness to refurbish Units 1 and 2 of the Bruce A facility—the remaining nuclear units at the plant that were not in operation—provided it could meet its investment rate of return for the electricity to be produced. Thus, Bruce Power's proposal to refurbish the Bruce A units came at a time when the province was looking for ways to increase its electricity-generating capacity. The province viewed the proposal as a unique opportunity to bring on a significant amount of reliable baseload supply in a relatively short time frame and to share the risks associated with a significant nuclear investment with the private sector.

In making its proposal to refurbish and restart Bruce A Units 1 and 2, Bruce Power was undoubtedly aware of the significant potential shortfall of energy supply in Ontario and the potential appeal to the province of restarting Bruce A Units 1 and 2, since they would produce 1,500 MW, or about 40% of the electricity required as a result of the shutdown of the coal plants.

THE NEGOTIATION PROCESS

Figure 3 is a chronology of the events that occurred during the negotiation process.

Appointment of Special Negotiator

In August 2004, after Bruce Power had approached the province with its offer, Cabinet approved the appointment of a "Special Negotiator" to negotiate an agreement with Bruce Power to refurbish and restart those units. The appointment of the Special Negotiator was confirmed by Orders-in-Council in September 2004 for the period from September to December 31, 2004. Subsequent Orders-in-Council in December 2004 extended the term to April 30, 2005. The Special Negotiator was accountable to Management Board of Cabinet (MBC) through the Minister of Energy.

Even though Ontario Power Generation (OPG) is the owner of the Bruce facilities and has expertise with respect to nuclear power plants, it was not involved in the negotiation. The Ministry was advised that involving OPG was considered undesirable from a commercial point of view: OPG is a generation company and not in the business of purchasing electricity; in addition, Bruce Power might have considered OPG's participation inappropriate since it would mean it was negotiating supply agreements with the province through a potential competitor.

Figure 4 summarizes the financial arrangements for the engagement of the Special Negotiator and other specialist assistance (see the following section for details on the other experts engaged).

The Ministry's Review Processes

We noted in our review that the processes followed by the province were sufficient to ensure that complete and objective information was available to the negotiators. Bruce Power provided the Ministry's Special Negotiator with, among other key documents, a detailed financial model that included its estimates of the costs of the refurbishment and the electricity support price that Bruce Power indicated it needed in order to receive—given the risks involved—an acceptable rate of return on its investment. Figure 5 lists key characteristics of this model. This detailed model allowed the Ministry to examine and assess the many assumptions and predictions made on the amount and timing of future cash flows, such as estimates for the capital investment needed for refurbishment

Figure 3: Events Leading to Final Refurbishment Agreement

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Early 2004	• Minister of Energy announces all coal plants, then generating about 20% of Ontario's electricity, will be shut down over the next four years
Summer 2004	• Bruce Power approaches province and offers to refurbish and to restart Units 1 and 2 in return for an electricity price that provides its required rate of return on investment • Cabinet considers options for managing Bruce Power's proposal • Cabinet approves appointment of Special Negotiator in August
September to December 2004	• formal negotiations commence • Special Negotiator undertakes exploratory discussions with Bruce Power and identifies three possible transaction options for consideration and further negotiation—options differ with respect to price of power required, number of units to be included, and nature of the transaction
December 2004 to February 2005	• under Cabinet direction, Special Negotiator works to negotiate lower price for Unit 1, 2 refurbishment by adding refurbishment of Units 3, 4 to deal
February to March 2005	• term sheet drawn up setting out key terms and conditions agreed to by two parties; forms basis for formal legal agreement • Minister announces on March 21 that a tentative agreement with Bruce Power has been reached
March to June 2005	• Ministry engages external legal, technical, and investment expertise • Ministry and advisers perform "due diligence," reviewing terms, supporting documentation, and Bruce Power's technical and operating assumptions • Ministry's advisers identify several issues and propose changes to term sheet • Ministry announces that closure of the province's last coal-fired generating station has been extended to early 2009
June to September 2005	• February 2005 term sheet discarded • Ministry, led by Deputy Minister and supported by advisers and staff from ministries of Energy and Finance, renegotiates the terms of the deal with Bruce Power
September 2005	• agreement in principle reached
October 17, 2005	• Minister of Energy announces agreement reached at price of 6.3¢ including fuel component • final agreement signed

and operating-cost requirements over the life of the refurbished units. The financial model was also used by both parties to assess the cost and revenue impacts of any proposed changes on the guaranteed initial electricity support price during the negotiation process.

Bruce Power and the Ministry agreed to an "open-book" process, and the Ministry was given access to a data room containing confidential documents provided by Bruce to support the refurbishment plans, supplemented by management presentations, facility site visits, and meetings with relevant government agencies.

To ensure that it had the expertise it needed to perform its review, the Ministry developed a plan to procure technical, financial, and legal advisers. Management Board of Cabinet approved the plan to acquire the necessary professional services in accordance with the principles and requirements of the government's procurement directives regarding consultants and goods and services (see Figure 4 for the costs of these services and the arrangements relating to the procurement of these advisers). We

Figure 4: Procurement of Specialist Assistance
Source of data: Ministry of Energy

Type of Assistance	Cost ($ 000)	Procurement Process
Special Negotiator (1 individual) + associates (2 individuals)	500 533	sole-sourced [1]
financial adviser (1 firm)	2,000	tenders issued for competitive bidding
legal adviser (1 firm)	460	tenders issued for competitive bidding
technical advisers (3 individuals @ under $25,000 each)	approx. 65	sole-sourced [2]
Total	**3,558**	

1. In this case, sole-sourcing was approved by Cabinet because the appointment was deemed urgent.
2. In this case, the Ministry forwent a competition involving larger firms because potential firms were either working or had worked for Bruce Power or OPG, and therefore concerns over conflicts of interest would have prevented the firms from bidding.

Figure 5: Key Characteristics of the Financial Model Used to Negotiate the Refurbishment Agreement
Prepared by the Office of the Auditor General of Ontario

Model enabled different variables to be plugged into an arithmetical calculation that generated the resultant electricity support price needed to enable Bruce A LP to earn its targeted rate of return on its investment.
Under model, price is to be paid for all energy produced by Bruce A units.
Calculation under model involved comparing cash flow associated with a "refurbishment scenario" with cash flow associated with a "non-refurbishment scenario," based on mutually accepted set of assumptions.
In refurbishment scenario, Bruce A LP's cash flow would result from: • refurbishing and operating Units 1, 2, 3; and • operating Unit 4 (including replacing steam generator in 2007) until expiry in 2017.
In non-refurbishment scenario, Bruce A LP's cash flow would result from: • not refurbishing any unit; • operating Unit 3 until expiry; • after expiry, maintaining Unit 3 in "laid-up state" (i.e., monitoring the non-operating unit to ensure it poses no danger because of risks such as radioactive leaks) until end of lease; and • operating Unit 4 (including replacing steam generator in 2007) until expiry.

noted that the engagement of these advisers was carried out in accordance with relevant government directives.

The review conducted by the Ministry and its advisers identified a number of issues and potential risks that needed to be addressed. Some of the more significant ones included:

- the absence of, and need for, mechanisms to protect against Bruce A LP making “windfall profits” from refinancing or transferring ownership;
- the absence of, and need for, a sharing of future efficiencies in operations, given that certain costs are difficult to project over 30 years;
- a cap on certain allowable Consumer Price Index (CPI) increases; and
- unreasonable assumptions made in such areas as staffing levels and time allowed for outages.

In addition to identifying and addressing a number of risks and issues, the Ministry also successfully negotiated a number of improvements to contractual clauses. As a result, we concluded that the provisions in place relating to timely construction and ongoing operating performance by Bruce A LP were generally reasonable. Specifically:

- Although Bruce A LP was not required to post completion and performance security under the Refurbishment Agreement, guarantees respecting TransCanada Pipeline and OMERS’s 63.2% ownership interest (through their subsidiaries) in Bruce B were required in case of non-performance in meeting completion reviews by Bruce A LP. The Ministry’s financial advisers deemed that the combination of the guarantee and a direct link to Bruce B units through the agreement was sufficient credit support and security.
- The Refurbishment Agreement requires liquidated damages, payable after six months, if the targeted commercial operation dates are not met. The Ministry indicated that the six-month time frame was reasonable because of the very long schedules and complex technical requirements involved when constructing and refurbishing nuclear generating facilities.
- Contracts typically have *force majeure* clauses—that is, if the supplier is prevented from meeting its obligations because of an event beyond its reasonable control, such as an act of God, it is relieved from its obligations. The agreement between OPA and Bruce A LP provides for cost-sharing based on the type of *force majeure* event involved, whereby Bruce ALP would assume more responsibility for those costs over which it has the most control.

BRUCE A LP’S RETURN ON INVESTMENT

The Rate of Return

Bruce A LP required that its investment in the project to refurbish nuclear units garner a return that would be commensurate with the risks it was taking. This targeted rate of return was the key variable in the financial model that was used to discount Bruce A LP’s expected cash flows and determine the resultant initial electricity support price. To assess whether this targeted rate of return was reasonable, the Ministry engaged one of Canada’s largest investment banking firms as its financial adviser.

In its report to the Ministry, the adviser noted that the rate of return fell within its estimate of what would be a commercially reasonable financial return on an investment of this nature of 10.6% to 13.8%. Overall, the adviser concluded that “the principal financial terms of the Financial Proposal, when taken together and considered as a whole, are fair, from a financial point of view, to the OPA.”

Tax Considerations

The rate of return was to apply after tax, on the critical assumption that Bruce A LP was a taxable entity. Accordingly, in the financial model that was used by both parties to calculate the price Bruce A LP needed to obtain its rate of return, the estimated taxes payable (using the corporate tax rate of 34.12%) were deducted in calculating the cash flows forecast to be received by the Bruce A LP partners throughout the period that it sells the incremental energy produced as a result of refurbishment.

With respect to this assumption of taxability, we note that Bruce A LP is owned by four parties as follows: TransCanada Pipelines (47.4%), OMERS (47.4%), and two unions (5.2%). While TransCanada Pipelines is a public company subject to corporation and other taxes, OMERS is a public-sector pension fund exempt from tax.

The Ministry accepted the advice provided by its financial adviser and an external regulatory expert on this matter. Specifically, even though OMERS—which constitutes almost one-half of Bruce A LP—is a non-taxable entity, it was deemed to be taxable on the basis of precedents involving regulated companies where, although there is no actual tax liability, there is likely a potential future one (in that, for example, pensioners may be subject to a tax liability in respect of pensions received). The financial adviser noted that recent precedent decisions by regulatory bodies also supported the concept of "deemed" income tax.

We note, however, that because OMERS does not pay corporate taxes on cash flows or profits received, its rate of return may well range from 16% to 21%. Given that OMERS has publicly stated that its targeted long-term annual rate of return on public infrastructure investments is 10% to 15%, the potentially higher return available to OMERS made the refurbishment a very attractive investment.

Effect on Negotiations

For Bruce Power, Bruce A LP's targeted rate of return was a critical factor during the negotiations. For the Ministry, key objectives relating to transferring risk and obtaining a reasonable electricity price were the critical factors. This created a negotiating environment whereby if the Ministry, in attempting to achieve its objectives, made proposals that would have an impact on Bruce A LP's required rate of return, then Bruce A LP could be expected to make counterproposals that would offset such an impact.

It was within this context—of the rate of return being such a significant factor in the negotiations—that we examined the provisions of the Refurbishment Agreement to determine the cost to the ratepayers of the additional energy that is to be produced as a result of the proposed refurbishment.

PROVISIONS LOWERING THE INITIAL SUPPORT PRICE

To obtain an initial support price of $63/MWh and yet allow Bruce A LP to earn its targeted rate of return if operating performance targets are met, the province allowed certain provisions and changes to previously agreed-to terms and conditions relating to the Bruce plant's other six units to be made. These provisions and changes give Bruce A LP cash flows that result in ratepayers paying the financial equivalent of a price of $71.33/MWh for the additional energy from refurbishment.

We discuss three of those provisions in the following sections. The title of each section, beyond identifying the provision, indicates our estimate of how much of an increase in the initially announced support price that particular item would have required if the offsetting financial benefit to Bruce A LP from that provision had not been included in the Refurbishment Agreement. Our calculations used the same financial model and assumptions agreed to by the parties negotiating the agreement.

Trade-offs Increasing Bruce A LP's Cash Flows

Rent Reduction (+ $2.48/MWh)

As part of the 2002 amended lease agreement, Bruce Power had to make annual supplementary rent payments of $25.5 million (subject to full inflation adjustment) to OPG for each operating unit of Bruce A. The Refurbishment Agreement reduces the amount of supplementary rent that would have been payable to OPG once each unit became operational. This reduction in Bruce Power's payments increases Bruce A LP's future cash flows and thereby functions as a trade-off in that the province obtained a lower support price in return.

In October 2005, the Minister of Energy, on behalf of the province as OPG's sole shareholder, issued a shareholder's directive to reduce Bruce Power's annual rent payments from $27.4 million to $6 million for each refurbished unit (since Unit 4 had already been restarted and was not to be refurbished, the rent reduction applied only to Units 1, 2, and 3 after refurbishment).

The original intent of the supplementary rent payments was to compensate OPG for the direct costs it bears for disposing of spent fuel and for giving up the return it could otherwise have made on taxpayers' investment in the plant assets. In contrast, with the reduced rent amount negotiated in the Refurbishment Agreement, OPG will be compensated only for its fuel-disposal costs and not for giving up return on taxpayers' investment in the plant.

We noted that the original rent amount would have afforded an opportunity for the price that ratepayers pay for OPG energy to be lowered (OPG became subject to price regulation following the 2002 lease amendments, first through government regulation and, from March 2008, through the Ontario Energy Board; the price set for OPG energy is to ensure that OPG recovers its costs and obtains the regulated rate of return). That is, by obtaining a greater rate of return through higher rent revenue, OPG would not have needed to obtain as much return through electricity-price revenue from ratepayers.

Based on our calculations, without this trade-off involving the rent reduction, the initial support price for Bruce A energy would have had to be increased by $2.48/MWh in order for Bruce A LP to maintain its required rate of return.

Subsidies on Existing Unit 3 Energy (+ $1.73/MWh) and Unit 4 Energy (+ $3.74/MWh)

The refurbishment proposal was aimed at compensating Bruce A LP only for the additional energy output produced by the refurbished units ("incremental energy output")—not for existing output from Bruce A Units 3 and 4. However, the agreement was expanded to include Units 3 and 4.

Unit 3

Prior to entering into the Refurbishment Agreement, Bruce Power was selling electricity on the open market and was receiving the actual market price with no subsidy. In contrast, under the Refurbishment Agreement, Bruce Power has been guaranteed an initial support price of $63/MWh (with similar CPI adjustments as those for Units 1 and 2), rather than the open-market price—which ministry and Bruce A LP experts projected would be lower—for the existing energy being supplied by Unit 3.

The Ministry viewed paying Bruce the support price rather than the market price as "ratepayer equity"—that is, ratepayers' upfront contribution to the capital cost of refurbishment. The Ministry indicated that, without contributing now to the financing of the capital costs of Units 1 and 2 via this higher price for Unit 3 energy, ratepayers would have to pay a significantly higher price for electricity once Units 1 and 2 come onstream.

The subsidy was capped at $575 million for electricity supplied by Units 3 and 4—that is, $575 million is the maximum amount that Bruce

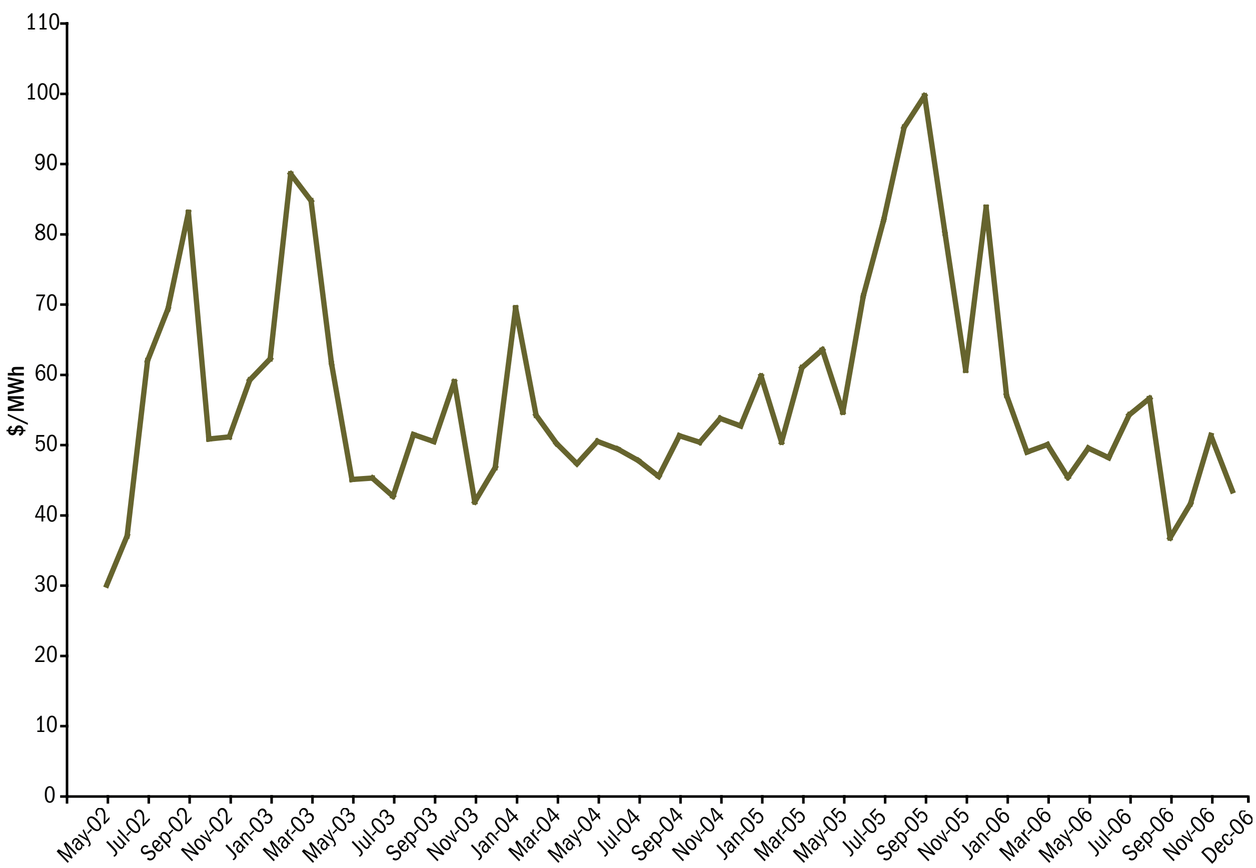
A LP may receive before Units 1 and 2 become operational.

A support price of $63/MWh is expected to be higher than the most likely market price for electricity. Specifically, the forecast that Bruce Power used when it proposed the refurbishment project to the Ontario government in the summer of 2004 and that independent consultants supported was a most likely market price over the next decade of between $50/MWh and $60/MWh (2005 dollars). At the time, the Ministry indicated that it had reviewed the projected price prepared by Bruce Power and told its financial advisers that these results were suitable to use in their financial analysis.

In subsequent discussions with us, the Ministry pointed out that, contrary to those projections, actual market prices in 2005 were significantly higher than expected, averaging $68.49/MWh. From this point of view, locking in a $63/MWh price for Unit 3 was advantageous. However, according to information published by the Independent Electricity System Operator (IESO), the year 2005 had exceptionally high electricity prices due to a number of factors: the summer had above-average hot temperatures, a few major plants scheduled outages for maintenance, and hurricanes Rita and Katrina contributed to a dramatic increase in natural gas prices. By comparison, as shown in Figure 6, since the opening of the electricity market to competition in May 2002, the wholesale electricity price from May 2002 to September 2004, when negotiations with Bruce Power began, has averaged about $51/MWh. As well, in 2006, monthly market prices in Ontario returned to recent historical levels, with monthly average prices

Figure 6: Historical Monthly Average Market Price of Electricity, May 2002–December 2006

Source of data: Independent Electricity System Operator



from January to December ranging from $36.80/MWh to $57.10/MWh and averaging $48.80/MWh.

Therefore, given that the average electricity price since the opening of the electricity market in 2002 has been about $51/MWh and that 2006 prices averaged in the $45–$55/MWh range, the $50–$60/MWh market-price range that was forecast for the next decade, used in the negotiations and agreed to by external experts, seems to be reasonable.

By providing Bruce A LP with the increased price of $63/MWh for existing energy from Unit 3 rather than the market price (again, estimated to be between $50/MWh and $60/MWh in the financial model), Bruce A LP was able to reduce the support price it needed to obtain its targeted rate of return. We estimate that, without trading off a subsidy on existing Unit 3 energy for an initial support price of $63/MWh, the province would have had to increase the initial support price by $1.70/MWh for Bruce A LP to obtain its required rate of return.

Unit 4

Even though Unit 4 is not going to be refurbished, the province agreed to extend the same support price to Unit 4's existing output. As with Unit 3, this amounts to a subsidy whereby Bruce A LP receives the newly negotiated $63/MWh support price for Unit 4's existing energy output rather than the market price it would otherwise have received. The $575-million cap on the subsidy applies to the total amount Bruce A LP receives for electricity supplied by both Units 3 and 4 up to the completion of the refurbishment of Units 1 and 2. Subsequent to the refurbishment, the cap will be removed.

We estimate that, as a result of this trade-off, Bruce A LP was able to lower the support price it received for the electricity produced by refurbished units by $3.70/MWh and still be able to earn its targeted rate of return if operating performance targets are met.

Pricing Support to Bruce B (+ 38¢/MWh)

As part of the negotiation, the Ministry agreed to provide a guaranteed minimum support price of $45/MWh plus an annual adjustment for CPI for the energy output of the Bruce B plant (with no fuel cost pass-through—Bruce Power, not the ratepayer, is to pay the costs of fuel for Bruce B). This provision, by which the province trades off subsidizing Bruce B energy for paying a lower initial support price for Bruce A energy, was made even though it compensates Bruce Power, whose partners are different from those of Bruce A LP.

The Ministry indicated to us that the price floor on Bruce B electricity was critical for Bruce Power for two reasons:

- The return to service of two additional units created additional baseload capacity that may have a dampening effect on the market price for power, which would have a negative impact on Bruce Power's asset values.
- Government actions such as the imposition of price caps have impacted the profitability of Bruce Power in the past, and a price floor would serve to counteract any such impact in the future.

When the market price drops below $45/MWh (the floor price), the OPA grants Bruce Power a subsidy to make up the difference. We believe this subsidy is particularly valuable to Bruce Power, insofar as the market price during off-peak hours can fall significantly below this floor price (it should be noted in this regard that Bruce Power, as a baseload electricity generator, must run continuously at full capacity regardless of the price its electricity obtains on the market). The Ministry indicated that prices would need to be consistently below the floor price for Bruce Power to benefit.

When the market price exceeds $45/MWh (adjusted for inflation), the OPA can recover subsidies previously granted. Nevertheless, based on its advisers' projections concerning the likelihood of price movements, the Ministry determined that this arrangement could be expected to cost $40 million. Using this estimate, Bruce A LP would have required an increase in the support price of 38¢/MWh to obtain its targeted rate of return if this trade-off had not been negotiated.

Combined Impact of Trade-offs

In summary, while the Refurbishment Agreement indicates a rate of $63/MWh as the initial cost of electricity, the trade-offs negotiated in the agreement will provide additional cash flows to Bruce A LP equivalent to $8.33/MWh. Thus, the all-in cost to ratepayers of the electricity produced by the refurbished units will be closer to $71.33/MWh, as outlined in Figure 7.

Annual Price Escalation

For Bruce A LP to obtain its targeted rate of return with an initial support price of $63/MWh, the financial model applied two escalator provisions. The first is a cost-escalation adjustment for annual inflation of 3.5% on salaries and other benefits and of 2.5% on all remaining capital and operating costs. The second is an annual increase in the guaranteed electricity support price based on the annual percentage change in the CPI. The annual increase agreed to was 100% of the change in CPI up to 2.5% and, if the actual CPI inflation was higher than 2.5%, 60% of the excess amount.

Figure 7: The Financial Impact of Negotiated Trade-offs on Initial Support Price
Prepared by the Office of the Auditor General of Ontario

	$/MWh
Announced Price (including fuel cost)	**63.00**
Impact of Trade-offs	
additional reduction in annual lease payments	2.48
pre-refurbishment subsidy, Unit 3	1.73
subsidy for Unit 4 energy	3.74
pricing support to Bruce B	0.38
Price with Trade-offs Incorporated	**71.33**

The province has contractual arrangements with other private-sector electricity suppliers such as natural-gas-fired power plants and renewable-power producers. These agreements are similar to the Refurbishment Agreement in that the operator receives a guaranteed support price for electricity produced. However, increases to the support price negotiated in these other agreements have generally limited the annual inflationary increase in the support price to 15%–20% of CPI.

While we acknowledge there is an argument to be made for allowing nuclear facilities a different increase because they have higher ongoing capital and operating costs, the point we wish to make is simply that, in terms of negotiating give-and-take, the higher the percentage increase allowed, the lower the initial support price can be. In the case of Bruce A LP, allowing 100% of CPI up to 2.5%, in conjunction with the cost-escalation provision, enabled the negotiation of a substantially lower initial support price (the $63/MWh price) while still enabling Bruce A LP to earn its targeted rate of return. For instance, had the annual CPI increase paralleled that given in other private-sector supplier contracts and been limited to 20% of CPI, the initial support price would have needed to be increased by $12.56/MWh to enable Bruce A LP to obtain the same rate of return. If 50% of CPI had been allowed (because of the higher ongoing capital and operating costs at nuclear facilities), the initial support price would have needed to be increased by $7.70/MWh.

From the electricity ratepayer's perspective, providing Bruce A LP with a price escalator of 100% of CPI means lower prices will be paid in the earlier years of the agreement, with the trade-off that higher prices will be paid in later years.

ITEMS THAT COULD HAVE REDUCED THE SUPPORT PRICE

As noted earlier, the Ministry did identify and address a number of risks and other issues inherent in such a large and complex transaction. However, during the course of our review, we noted several items that we believe, had they been handled differently, could have reduced the negotiated initial support price by a total of about $3.60/MWh without affecting Bruce A LP's targeted rate of return. In our discussions with the Ministry on the issues we raised, the Ministry indicated that the discount rate that we used to calculate the present-value impact of these items results in an inconsistent basis for comparison with the overall financial model and leads to an overestimate of the impact of these items on the support price. We do not agree with the Ministry's position on the appropriate discount rate (see the Appendix for details of our and the Ministry's views on this matter). In the following sections, we calculate the impact in present value using the discount rate that we and our advisers deemed appropriate.

We discuss five items in the following sections; the title of each section, beyond identifying the item, specifies how much of a reduction to the support price the inclusion of the item in the financial model could have achieved while still enabling Bruce A LP to earn its targeted rate of return.

Lay-up Costs—Bruce B (– $1.24/MWh)

Although Bruce Power's offer related only to the refurbishment of Bruce A Units 1, 2, and 3, the Refurbishment Agreement included a provision pertaining to Bruce B for which we questioned the rationale.

Bruce Power's lease agreement with OPG covering both Bruce A and B expires on December 31, 2018 (with a series of 13 options for extending the lease for up to another 25 years). The end of the initial lease period coincides with the end of the expected useful life of the Bruce B plant. When nuclear reactor units reach the end of their operating life, there are three available options:

- decommission them;
- refurbish them; or
- maintain them in a laid-up state pending possible future refurbishment.

These options applied to the units of Bruce A when they were shut down between 1995 and 1998. At that time, OPG decided to maintain them in a laid-up state. When Bruce Power took over Bruce A in 2001, the lease agreement granted it this same option provided Bruce Power assume the lay-up costs, which it did.

As we noted with the provision granting pricing support to Bruce B (see page 14), we would have expected all of the provisions in the Refurbishment Agreement to deal only with Bruce A and not with Bruce B, since the operation of Bruce B involves different partners than does the operation of Bruce A. The original lease agreement for Bruce B required that Bruce Power assume the lay-up costs of Bruce B if it chooses to renew the lease. However, the Refurbishment Agreement changed this to require that ratepayers assume the lay-up costs of Bruce B from 2019 to 2036. These estimated costs over this time period total $2.6 billion and include annual expenditures for operating and maintenance services and salaries and benefits for 344 staff for the 17 years. Had the Bruce B lay-up costs been excluded from the Refurbishment Agreement, the support price for Bruce A energy could have been reduced by $1.24/MWh. We estimated that, if the support price had been lowered by this amount, ratepayers could have saved $518 million in present-value 2005 dollars. (The Appendix provides details on our calculation of "present-value 2005 dollars." Henceforth in this report, all references to "2005 dollars" should be understood to mean present-value 2005 dollars, as characterized in the Appendix.)

As an aside, we noted that the Ministry's technical advisers had indicated that the 344 staff added to support the lay-up of Bruce B was an unreasonably high number. The Ministry informed us that it successfully negotiated the inclusion of a provision in the Refurbishment Agreement whereby costs would be adjusted on the basis of actual staffing needs. However, the adjustment would result in ratepayers recovering only a portion of the costs they would already have paid and would apply only if the units are decommissioned.

Equally importantly, if the units are refurbished at the end of their useful lives, there will be no lay-up costs, yet Bruce A LP will already have been paid in advance for these costs as they are included in the higher support price it receives from 2005 to 2036.

The Ministry has indicated to us that, if the Bruce B units are refurbished, the refurbishment contract in 2019 would be negotiated so as to claw back or recapture the Bruce B lay-up costs now incorporated in the Bruce A price. However, there is no provision in the Bruce A Refurbishment Agreement for recovery of money already paid to Bruce A LP through higher electricity prices paid for almost 15 years to 2019, so the Ministry's ability to successfully negotiate such a clawback is open to question.

Aside from the financial impact on the support price of compensating Bruce A LP for lay-up costs, this trade-off also results in the province losing control over the facility, which prevents it from being able to choose to dispose of the units differently or negotiating different arrangements with another operator.

Additional Output from Fuel Enrichment (– $1.23/MWh)

The Canadian Nuclear Safety Commission (CNSC) has applied to the Bruce A units a regulatory standard that safeguards against potential loss-of-coolant accidents. The standard requires that the units operate at only 92.5% of their maximum capacity. This is the capacity at which the currently operating units are running.

Other than by lowering capacity, potential loss-of-coolant accidents can also be minimized by rebuilding the reactor or by the use of enriched uranium fuel. Bruce Power has been working on the latter option to increase its allowed capacity while still addressing safety concerns. It has, with the help of Atomic Energy of Canada Limited, developed a slightly enriched fuel (called "low void reactivity fuel").

The financial model calculates Bruce A's energy output based on the 92.5% capacity. However, the Bruce A refurbishment project descriptions submitted to the CNSC show that Bruce A units will be using the enriched fuel and are therefore expected to be able to operate at 95.5% capacity (the Ministry's technical adviser on fuel confirmed that the gain in electricity output for the Bruce A refurbished units would be about 3%, or roughly 25 MW, after taking into account the capacity limitation of Bruce A's turbine generator).

Given that the OPA—and not Bruce A LP—is now responsible for fuel costs (the uranium and related processing), we felt the potential financial benefits from the increased electricity output from using the more costly enriched uranium fuel should have been reflected in the financial model. Had the impact of the potentially increased electricity output been included in the model, it would have allowed the initial support price to be reduced by up to $1.23/MWh. We estimated that, if the initial support price had been lowered by this amount, ratepayers could have saved up to $514 million in present-value dollars.

The Ministry indicated that it had considered the potential for enhanced output from Bruce A resulting from the use of enriched fuel and stated that its understanding is as follows:

- It was CNSC that had asked Bruce Power to commit to considering the use of enriched fuel in the refurbished Bruce A units.
- Bruce Power has noted the potential to use enriched fuel in its Environmental Assessment Filings, but no firm commitments have been made.
- The Ministry's fuel adviser had noted the potential for a 3% capacity enhancement—from 92.5% capacity to 95.5% capacity—for the Bruce A units from the use of enriched fuel. The Ministry indicated, however, that its fuel adviser did not consult with its technical advisers or Bruce Power with respect to any physical constraints that plant systems and operations might impose on this potential. Also, the changes needed to be made to the plants to achieve the increased capacity have not been analyzed or estimated at this time and may be prohibitively expensive.

Documents made available to us showed Bruce Power's intention to seek approval to use enriched fuel in Bruce A's reactors and operate them at maximum power. Our review of the project description that Bruce Power submitted to CNSC also showed that, subject to CNSC approval, the Bruce A project activities would potentially include using enriched fuel and subsequently operating at an upgraded maximum reactor power, currently expected to be 95.5%.

Using enriched fuels costs two to three times more than using normal fuel. This additional cost is now passed on to ratepayers under the terms of the Refurbishment Agreement.

The Refurbishment Agreement contains a provision for negotiating an incremental price for the incremental energy produced if the Bruce A plant should operate at a capacity above 92.5%. However, the ability to successfully negotiate a new price after committing to pay for the higher fuel costs does not necessarily ensure that ratepayers will be appropriately compensated for the additional costs they have already incurred from paying for enriched fuel.

Alternatively, ratepayers should only have been required to assume the cost of regular fuel—with Bruce A LP having to pay the incremental cost of the enriched fuel in order to retain any financial benefits from its use.

Higher Net Electricity Output in Early Years (– 47¢/MWh)

The financial model assumed a consistent electricity output of 750 MW per year from each refurbished unit. However, the Ministry's technical advisers had noted that, according to indications in the Bruce A technical reports, the turbine generator could produce a net output of 776 MW. In addition, new steam generators may initially enhance unit output. The advisers asked Bruce Power to review the financial-model assumption, and Bruce Power responded that 750 MW was a reasonable estimate of average net output over the lifetime of the plant.

However, our review showed that, in the earlier years of service, the four Bruce A units performed at levels that were among the best in the world, displaying the highest gross capacity factor. In the later years of their operation from the late 1980s onwards, the performance of Bruce A deteriorated, due to several factors including staffing issues and degradation of equipment due principally to problems associated with fuel channels and steam generators. The Ministry indicated that the assumption in the financial model of a net output of 750 MW from the refurbished Units 1 and 2 was based on the historical output of Units 3 and 4 when they were restarted. However, we noted that Units 3 and 4 were restarted without replacement of the degraded major components contributing to deteriorated performance. In contrast, when Units 1 and 2 are refurbished, the fuel channels and steam generators will be replaced, so the refurbished units should in the early years achieve a rating of 769 MW, which is also the rating that Bruce A LP included on its own website at the time of our review as the projected net electricity output of the refurbished Units 1 and 2 (compared to 750 MW for Units 3 and 4).

While we acknowledge that the most likely scenario is that using 750 MW as an average output over the life of the refurbished Units 1 and 2 is not unreasonable, it is likely that the units could produce more output in the years immediately following refurbishment and less output in later years with the average being 750 MW/year.

The benefit of the cash flow to Bruce A LP is different depending on whether Bruce A LP is being paid for an evenly maintained output over the years or it receives more money in early years for higher capacity and less money later as output diminishes. Cash received today is worth more than the same amount of cash received later—an effect known as cash-flow discounting.

We calculated that, if the financial model had based the average output of 750 MW on an output of 769 MW for the first half of the units' life cycle and 731 MW for the second half, the support price for Bruce A energy could have been reduced by 47¢/MWh while still allowing Bruce A LP to earn its targeted rate of return. We estimated that, if the support price had been lowered by this amount, ratepayers could have saved $196 million in 2005 dollars.

We noted that the Refurbishment Agreement provides for the sharing of benefits of operational performance above the 750-MW level. However, there is no assurance that ratepayers would actually benefit from the increased output as the determination of such sharing of benefits is also dependent on a number of other factors.

Lay-up Costs—Bruce A Units 1 and 2 (– 49¢/MWh)

As outlined in Figure 5, the financial model used in negotiations compared Bruce A LP's cash flow if it undertook the proposed refurbishment with its cash flow if there were no refurbishment. A major component of these cash flows is the costs involved in the two scenarios. We noted that the model did not include all of the no-refurbishment-scenario costs. Specifically, while these costs correctly included the lay-up of Unit 3 (that is, the costs for monitoring that Unit 3, once its operating life expires, is safely maintained against risks such as radiation leaks), they failed to include the lay-up costs of Units 1 and 2, which, if not refurbished, would still need to be maintained until the units are returned to OPG when the lease expires on December 31, 2018.

With refurbishment, such lay-up costs are avoided, which should lead to a lower support price needed for Bruce A LP to obtain its targeted rate of return. Had these savings been properly reflected in the financial model, the support price for Bruce A energy could have been reduced by 49¢/MWh while maintaining the targeted rate of return. We estimated that, if the support price had been lowered by this amount, ratepayers could have saved $205 million in 2005 dollars.

While acknowledging that the financial model did not include the savings to Bruce Power for no longer having to incur lay-up costs for Units 1 and 2, the Ministry indicated that the following should be taken into consideration:

- In the refurbishment scenario, the costs of "Other Material and Services" for refurbishing Units 1 and 2 from 2005 to 2009 were excluded from the financial model. If these costs had been included, they would have more than offset the effect of not including the lay-up costs in the no-refurbishment scenario.
- If refurbishment were not to occur, Bruce Power could apply to the CNSC for a change to its operating licence to significantly reduce the costs of overseeing the lay-up of units at the Bruce facility. For example, the units could be dewatered and defuelled, the systems dried, and the reactor building sealed; and

staff levels could be reduced to a caretaking level whereby only heating and a few pieces of equipment would be maintained. With the lay-up costs thus significantly lowered, the effect of not including them in the no-refurbishment scenario is accordingly reduced as well.

With respect to Other Material and Services costs, we questioned how they could be incurred if Units 1 and 2 of Bruce A were not refurbished. These costs—examples of which include purchased services such as waste management, detritiation of heavy water, and certain engineering services, and materials such as equipment parts, radiation clothing, and tools—result from operating and maintaining functioning units. Units 1 and 2, however, had been laid up for close to a decade at the start of the 2005–2009 period. Only if a unit has been operating and is subsequently closed down for refurbishment would some of these costs, such as waste management and detritiation, continue to be incurred for some period—again, this was not the case for Units 1 and 2 of Bruce A.

With respect to the measures the Ministry indicated Bruce Power could take to reduce the costs of the lay-up of Units 1 and 2 of Bruce A, we noted that ratepayers have already been making payments toward the full future lay-up costs of Bruce A Unit 4 and all the Bruce B units. If, according to the Ministry, applying to the CNSC would likely result in a significant cost reduction, we questioned why these measures have not been considered for reducing the lay-up costs included in the financial model for Unit 4 of Bruce A and all the units of Bruce B.

A Mechanical Error in the Financial Model (– 21¢/MWh)

The financial model's calculation of the support price Bruce A LP would need to achieve its targeted rate of return included removing the effects of debt financing. We noted a mechanical error in this aspect of the calculation.

Specifically, the effect of tax savings on certain interest expenses was counted twice in the removal of debt financing effects, resulting in an overstatement of the price Bruce A LP would need to obtain its targeted rate of return. We calculated that correcting this error would have reduced the support price for Bruce A energy by 21¢/MWh. We estimate that ratepayers could have saved $88 million in 2005 dollars over the life of the agreement if the support price had been lowered by this amount.

The Ministry's financial adviser indicated to us that it was aware of the mechanical error—but that it had been discovered only two days before the signing of the agreement and had informed the Ministry of the error at that time. In addition, the Ministry advised us that, in its opinion, seeking a late price adjustment based on this error and the lay-up costs for Bruce A Units 1 and 2 was made unnecessary by the existence of other errors found by the OPA and Bruce A LP that cancelled out the effect of these two items on the price. However, in our opinion, the documentation that the Ministry provided to us did not support its assessment of the errors it cited as offsetting.

RESPONSIBILITY FOR COST OVERRUNS

Under the Refurbishment Agreement, Bruce A LP expects to invest $4.25 billion (in nominal dollars) to cover the capital costs of refurbishing the Bruce A facility. This investment is divided up among the four units as follows:

- $2.75 billion to refurbish Units 1 and 2;
- $1.15 billion to refurbish Unit 3 when it reaches the end of its operational life in 2009; and
- $350 million to replace Unit 4's steam generators.

For each of these three estimates, the province and Bruce A LP agreed on provisions for dealing with the actual cost coming in at either greater than or less than the estimated costs. Specifically, these provisions lay out how cost-overrun risks and potentially realizable savings are to be shared. They are examined in the following sections.

Provisions for Units 1 and 2

Our review of the capital-cost estimates to refurbish Units 1 and 2 showed that Bruce Power had engaged various consultants to provide independent reviews and analyses of the risks of the refurbishment project. The latest review and update, which considered these consultants' findings, was issued in May 2005. This latest commissioned review was completed between March 31, 2005, and April 21, 2005, with input from both representatives of the owners of Bruce Power and the project team responsible for managing the refurbishment project. The results of this review were to be used by Bruce Power in deciding whether to go ahead and in managing project risks during the execution of the project. The Ministry provided us with a copy of the last consultant's report, submitted by Bruce Power, during our review.

The consultant's work included a risk analysis of the project's schedule that incorporated the most recent estimates received from major contractors, as well as other details that had not been available in the earlier analyses. In analyzing the capital-cost risk of the project, the consultant considered the effects of factors that typically apply to large complex projects and the possibility of major disruptive events that could conceivably shut down the project for a period during execution.

The consultant produced a risk profile for the estimated capital costs of refurbishing Units 1 and 2. The results were compared to the estimates prepared by Bruce Power's refurbishment project management firm. The differences identified were slight and believed to be well within an acceptable range of accuracy for a project of this magnitude. The total cost, including contingencies, was estimated to be \$2.5 billion, with a 10% probability that the refurbishment might cost as much as \$2.8 billion.

The Ministry's technical advisers' review of the available documentation also indicated that the estimated capital costs and allowance for contingencies were reasonable. The technical advisers also concluded that the risk of cost overruns was low, for the following reasons:

- Bruce A LP had a well-thought-out approach to project management that incorporated lessons learned from Bruce Power's experience with restarting Units 3 and 4 and OPG's experience with the refurbishment of Unit 4 of the Pickering "A" plant.
- Experts and contractors were extensively involved in defining the scope of the refurbishment and consolidating work within that scope, and over 70% of the cost of the work had already been established under fixed-price contracts.
- Proper accountability had been established internally, and assurance had been obtained from key contractors that qualified staff with extensive relevant experience would be provided.

Our review showed that, even though the most likely cost of refurbishing Units 1 and 2 was estimated to be \$2.5 billion (including an allowance for contingencies), a cost of \$2.75 billion was used both to calculate the support price and as a base for sharing any cost overruns or savings in the Refurbishment Agreement.

The Ministry was aware of the \$250-million increase and informed Cabinet of it in September 2005. The Ministry indicated that its advisers and Ontario Energy Board staff were to confirm the updated cost estimates. Our review showed the following:

- One technical adviser, upon talking to Bruce A LP, concluded that the "\$2.75 billion seems reasonable given the delay and the use of escalated dollars." The technical adviser suggested that the Ministry "consider a financial audit of the \$2.75-billion price when the

contract is signed." No financial audit was done to confirm the amount, however.
- Ontario Energy Board staff were not asked to confirm the $2.75-billion estimate.
- In September 2005, the Ministry asked the IESO for its opinion on the reasonableness of the $250-million cost increase given that Bruce A LP had itself indicated earlier to the Ministry that contract cost increases would be substantially less than $250 million.

Given that the $250-million increase added as much as $1.56/MWh to the support price, we were concerned that such a significant increase in cost between May 2005 and September 2005 was not substantiated, especially with respect to the fixed-price contracts, which accounted for 70% of the total costs.

We were also concerned about the fact that, if the actual costs come in at the June 2005 estimate of $2.5 billion, ratepayers will still pay about $2.7 billion (since the support price is based on $2.75 billion and the cost-sharing formula is structured to allow only $50 million of the excess payment to be recovered). We understand that actual costs incurred will be audited by the OPA, but the results of these audits will not have any impact on the sharing formula agreed to.

Provisions for Unit 3

The capital cost for refurbishing Unit 3 was set at $1.15 billion in the Refurbishment Agreement. This cost included a significant allowance for contingencies, which is included in the financial model used to calculate the support price. However, under the terms of the Refurbishment Agreement, if the cost comes in under $1.15 billion but more than the estimate before contingencies, Bruce A LP will keep most of the "savings" under $1.15 billion, with ratepayers getting between 0% and 50% through adjustments to the support price. Ratepayers therefore obtain little benefit if the contingency allowance is not spent.

Provisions for Unit 4

The total cost of replacing the steam generators was estimated to be $350 million. Months before Bruce Power approached the province with its refurbishment proposal, Bruce Power had already received approval from its Board of Directors to purchase these steam generators to avoid losing $2 billion of revenue in the event of Unit 4 being prematurely shut down.

Our review of the financial model indicated that the cost of the replacement had been properly included in the non-refurbishment scenario of the financial model and was not assumed by ratepayers. However, there is a provision in the Refurbishment Agreement whereby the OPA and Bruce A LP are to share the excess cost if the generators cost more than $350 million. Since Bruce Power's decision to replace the steam generators, made to avoid losing $2 billion in revenue, predated the refurbishment proposal, we questioned why ratepayers should share the risk of cost overruns.

OTHER MATTER

Transmission Capacity

There is a "deemed-generation" provision in the agreement that allows Bruce Power and Bruce A LP to get paid without generating electricity. Specifically, if a lack of transmission capacity to support the flow of electricity from the Bruce plants to the power grid prevents the plants from generating electricity, the OPA will have to pay Bruce Power and Bruce A LP the market price for the electricity it would otherwise have generated.

If a unit or units have to be shut down due to lack of transmission capacity in the Bruce Peninsula, it is understandable that Bruce receive some compensation for underutilized capital facilities, as well as for some variable costs that would undoubtedly be incurred. However, Bruce is to receive the full market price for any lost production caused by insufficient transmission capacity. We have the following observations with respect to this:

- If the units are not operating Bruce will have some, and perhaps significant, savings in their variable costs and accordingly we would have expected there would have been a reduced price paid for electricity not generated by an idled unit. By paying the full market price, our concern is that Bruce will have a higher profit margin when the plants are not operating than when the plants are operating.
- Even though the agreement is for energy output from the Bruce A units, ratepayers are required to pay Bruce Power—a separate ownership group—for deemed generation from the Bruce B units. In addition, the payments for the energy not produced are "to be attributed in whole first to Bruce B" units, with any excess deemed-generation payments to be subsequently attributed to Bruce A units. The Ministry itself stated that "there is no way to determine which option [paying Bruce A or Bruce B first] would place the Province in a better (or worse) position." Since Bruce B was never entitled to any such "deemed-generation" payments under the existing agreement, we do not see what benefit ratepayers received for providing this protection to Bruce Power now.
- If the lack of transmission capacity results in electricity shortages, this will likely cause the market price to escalate significantly. Therefore, Bruce B will reap this much higher market price. For instance, in summer 2005, when hurricanes hit the Gulf of Mexico and took out significant natural gas capacity, electricity prices temporarily soared to a range of \$70/MWh–\$80/MWh. We are not convinced the Refurbishment Agreement sufficiently mitigates this risk to the ratepayers. A more reasonable price from the ratepayers' perspective would be the guaranteed floor price of \$45/MWh (adjusted for inflation) for Bruce B's deemed-generation output if Bruce B units need to be idled due to lack of transmission capacity.

We understand that current transmission capacity will not be sufficient to support all the energy to be produced by the eight units of Bruce plants A and B. Ministry staff indicated to us that they were well aware of this potential issue and that the risk of transmission inadequacy will exist only if all eight Bruce units are generating output. To help mitigate this risk, a provision in the refurbishment agreement states that no deemed generation for output from an eighth unit is to be allowed prior to 2012. We were also advised that the IESO has made plans to accommodate the return to service of the Bruce A Units 1 and 2, as well as the additional electricity produced from emerging, renewable-source, wind-generation capacity in the Bruce Peninsula.

While we understand from the Ministry that Hydro One is currently preparing an application for the construction of a new transmission line, the work that the IESO has identified as needing to be done in conjunction with such construction is not guaranteed to proceed as planned, since some of it must be assessed for environmental impact and must receive the approval, after consultation, of local communities spread across a wide geographic area. Therefore, we believe that, particularly in light of the deemed-generation provisions in the Refurbishment Agreement, it is essential that the Ministry continue to address the risk that there may not be sufficient transmission capacity. The Ministry advised us that it has a number of initiatives under way to mitigate the risk of insufficient transmission capacity and therefore having to pay the Bruce partnerships for power not produced.

Appendix

FACTORS CONSIDERED IN QUANTIFYING FINANCIAL IMPACTS

The financial impacts on the ratepayer of the issues identified in our review are projected to occur throughout the term of the Refurbishment Agreement (that is, from 2005 to 2043). Cash flows throughout this period will have different economic values depending on the year they occur. To better measure the value of these cash flows, it is useful to convert them to the value they have as of a common date. In our review, we convert them to their value as of October 17, 2005 (the date of the Refurbishment Agreement). We call this the "present value" for that date.

There are three factors to consider in determining present value:

- The first factor involves the principle of "discounting," which in turn is based on the notion that a dollar received today is worth more than a dollar that will be received in a year. This is true because a dollar received today can be invested to earn a return, or interest. Cash flows that are not received until some point in the future are worth less because they are not currently available to be invested. By way of illustration, if current interest rates are 4% per year, $100 to be received in one year's time is only worth about $96 today. That is, if the $96 is immediately available and is invested for one year with interest rates at 4%, it is worth about $100 in one year's time. The same principle applies to future payment obligations.
- Price or cost inflation is a second factor that contributes to the difference between present and future value. Inflation is defined as the decrease in the buying power of money over time, and it occurs when the cost of a good or service increases over that time. Therefore, in order to express future costs in "today's dollars" of buying power, the effects of inflation must be eliminated.
- A third factor in converting future cash flows to a present value is the effect of uncertainty, or risk. Forecasts are based on assumptions that may or may not reasonably predict the future.

With respect to the first factor, for issues that we identified as having a financial impact on ratepayers, we calculated the present-value amount by discounting future cash flows using interest rates based on ratepayers' "cost of capital." That is, we used the rate of return that a ratepayer could be expected to earn on cash invested. However, the Ministry believes that, in this situation, the appropriate discount rate to use is Bruce A LP's targeted rate of return because it reflects project risks, including operational and production uncertainty. Bruce A LP only gets paid to the extent that it produces electricity, and ratepayers only pay if Bruce A LP is successful and able to produce electricity. In other words, the likelihood of ratepayers having to make payments for Bruce A power is not certain and is directly tied to the riskiness of the project, and the Ministry believes that the same risk-adjusted discount rate should be used in calculating the present value of the project and impact on ratepayers.

Because of this disagreement, we engaged an external firm to give us an opinion on the most appropriate discount rate to use. The firm concluded that the ratepayers' perspective, rather than Bruce A LP's perspective, is most relevant in evaluating the impact of any additional costs being assumed by ratepayers as a result of the Refurbishment Agreement. Viewed from the perspective of ratepayers, Bruce A LP's required rate of return for the risks it is assuming is irrelevant. Accordingly, the firm recommended that, given the specifics of this particular situation, the most appropriate interest rate to use to discount the future cash flows back to 2005 dollars would be that of Government of Canada Long-Term Real Return bonds. We therefore used that rate in our calculations.

With respect to the second factor, we and the external firm concluded that the inflation rates provided in the Refurbishment Agreement were appropriate for applying to present-value calculations.

As for the third factor, given the extremely high degree of certainty that ratepayers will continue to be obligated to pay the cost of electricity, there is very little to no risk that the situation will change and ratepayers will not have to be required to pay.

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