The Ontario Government's proposals on electricity restructuring: Comments by Public Service International Research Unit

by

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1. Executive summary

An attempt in 2002 to reform the Ontario electricity industry by introducing competition and a greater role for the private sector failed within six months because prices increased sharply. New reform proposals were announced by the Liberal Ontario Energy Minister in June 2004. This paper reviews these proposals and comments on their likely impact.

Under the new proposals, the key body would be a new Ontario Power Authority, which would be required to monitor supply and demand and, where necessary, intervene to commission the construction of new facilities to ensure supply security. The wholesale market would continue and retail competition would be re-introduced. The network company, Hydro One and the publicly-owned generator, Ontario Power Generation (OPG) would continue but OPG would be heavily constrained from contributing to the construction of new capacity.

About 24,000MW of new (or refurbished) generating capacity is expected to be needed by 2020 primarily because nearly all the nuclear capacity (14,000MW) will need to be refurbished or retired and because the new Liberal government has decided to close Ontario's coal-fired plant (about 7500MW) by 2007. More than half of this plant need will be before 2010 so urgent decisions and preparations need to be taken on the nuclear plants and on the mechanism for new plant construction if Ontario is not to suffer significant capacity shortages. Experience elsewhere, especially Europe, suggests new capacity will be primarily gas-fired. This raises issues about the adequacy of gas resources available to North America to sustain a significant increase in demand from new gas-fired stations.

It seems likely that few, if any non-Canadian companies will be interested in building plants in Ontario and careful assessment is needed to ensure Canadian companies can meet the required investment need, especially if OPG is not allowed to participate. While the proposals imply new investment will primarily be provided by the market, it seems likely that investors will prefer to wait till a capacity shortage is forecast by the Ontario Power Authority. The Power Authority will then be forced to run a competition to build new capacity and will award the winning bids long-term contracts.

Unless existing generators can be forced to guarantee they will not exit the market and new generators are forced to stick to their forecast construction schedules, it will be difficult if not impossible for the Power Authority to forecast capacity availability in order to identify plant need in time for new capacity to be built.

The situation is complicated by the NAFTA and GATS (General Agreement on Trade in Services) agreements. The terms and implications of these agreements are far from clear, but under both agreements, once a sector is opened up, it will effectively be impossible to go back to a planned approach no matter how disastrous the results of failed reforms. The NAFTA agreement also does not allow restrictions on trade, so even if Ontario nominally has enough capacity to meet demand, if prices are higher elsewhere, this capacity might not be available to Ontario.

It is difficult to predict the impact of the new capacity needed on prices, but the more competitive the environment, the higher the risk will be for new investment and this will be reflected in the cost of capital for new construction, perhaps doubling it. Given that for all power plants, repaying capital is a major element in the overall cost of power, doubling this cost is likely to push up the cost of power. Preventing OPG, which is likely to have a low cost of capital from participating, will only exacerbate this effect.

The Ontario government has begun to test the new system by issuing a Request for Proposals for 2500MW of 'clean' power and 300MW of clean capacity, including demand side measures. These will provide valuable information on what companies will be interested in investing in Ontario, what terms they will require, and what the completion rate of successful proposals is. There is a significant risk that interest will not be very great, that investors will require fully guaranteed income and that a significant proportion of the successful bidders will not complete their plants or will complete them later than forecast. This places further doubt on the efficacy of the proposed new system.

Outside Canada, retail electricity competition has generally been welcomed by large users, who have the resources and incentives to exploit the market potential to the full. Small consumers are either not interested in switching or, as in Britain, they appear not to be able to identify the cheapest deal. This makes it easy for retail suppliers to exploit small consumers and save their best prices for more price-sensitive large users.

It is concluded that Ontario faces a heavy investment requirement in the electricity sector over the next 6-8 years. To abandon the old publicly owned monopoly model, which, despite some faults, has a good record of ensuring supply security over many decades, in favour of a model with at best, a mixed track record seems unduly risky. It is recommended that:

- The attempt to introduce wholesale electricity competition is abandoned in favour of a more planned approach that ensures Ontario has enough capacity to meet its own needs;
- A review of gas resources available to Ontario be carried out if it is expected that a significant proportion of new plant is expected to be gas-fired;
- Clarification should be sought on the implications of the NAFTA and GATS agreements. Because of the impossibility of reversing commitments, none should be made under GATS and all possible protections taken under NAFTA until it is clear that the model adopted for Ontario is viable;
- Attempts to introduce retail competition should be abandoned because of their likely adverse impact on small consumers;
- The government should not attempt to privatise Hydro One and OPG and should allow OPG a much greater role in building new capacity, including ensuring it has the financial resources necessary; and
- Decisions are urgently needed on the future of the coal and nuclear plants. Retaining the coal plants at least for a little longer than is currently planned may help smooth the demand for new generating capacity, while many of the nuclear plants will soon need to be either refurbished or closed. Decisions on these matters should be taken by the Ontario people through clear, democratic processes.

2. Introduction

Ontario's Conservative government implemented full wholesale and retail competition in May 2002, but just six months later was forced to suspend retail competition for most consumers, capping prices and refunding excessive charges when price spikes caused a public outcry. The previous government's plan was also criticized because it did not encourage the development of new generating capacity, leaving the province with the prospect of capacity shortfalls. In June 2004, the Liberal Ontario Minister of Energy, Dwight Duncan, announced a new proposal for an 'Electricity Restructuring Act' to the Ontario Legislature. This paper reviews these proposals and comments on their likely impact.

3. The proposals

The key body in these proposals appears to be the Ontario Power Authority, a public body, at arms length from government, expected to be set up in January 2005. The Ontario Power Authority will have the responsibility to monitor supply and demand and, where appropriate, to commission the construction of new supply and demand facilities[1]. The Ontario Power Authority would be required to set up an energy conservation bureau. The wholesale electricity market would continue, largely unchanged and choice of retail supplier would be available to all consumers, although small and domestic consumers would be able to choose a regulated tariff.

Other changes will only have a limited impact on the construction of new power plants. The Independent Electricity Market Operator (IMO) will be renamed the Independent Electricity System Operator and the responsibility for monitoring for market abuses will be transferred from the IMO to the economic regulatory body, the Ontario Energy Board.

The government has pledged to increase incentives for energy efficiency and for renewable sources. It is clear that such measures will require strong government support and the use of public funds to support them. The 'market' will not provide these unprompted.

As a first step to stimulating the construction of new capacity and energy efficiency, in June 2004, the Ontario government announced it would be launching a Request for Proposals (RFP) for 300MW of 'green' (renewable) capacity and for 2500MW of 'clean' capacity (not oil or coal), either new generation or demand side measures.[2] The bids that offer the lowest costs, making up 300MW and the 2500MW will be awarded contracts that are guaranteed to cover the bid costs.[3] OPG will not be allowed to participate in the 'green' RFP and will be heavily restricted in its role in any bids for the 'clean' capacity.

4. The previous reforms

In 2002, the Ontario electricity market was opened to competition with the introduction of a wholesale spot market and, from May 1, the launch of retail competition for all consumers. Small consumers could either purchase from a competitive retailer (about 1 million of Ontario's 4.4-million retail customers chose this option) or 'standard supply service' (SSS) from their local distribution utility. Those that chose the latter paid rates based on the fluctuating price in the Ontario wholesale market. In 1999, in preparation for this, the integrated company, Ontario Hydro, owned by the province of Ontario was split into a network company, Hydro One and a generating company, Ontario Power Generation (OPG). Measures were introduced to break the dominance of OPG in generation partly through plant sales, for example, the Mississagi River system

[1] This appears to include both generation and transmission facilities, although in this document, we concentrate on generation facilities.

[2] Details of the Requests for Proposals can be found at http://www.ontarioelectricityrfp.ca/Index.aspx

[3] The website for the RFP states for the 2500MW RFP that: 'The goal of the Economic Evaluation is to choose, from among the Proposals that have met the minimum technical and financial requirements, the Proposals for: New Generating Facilities and DR Projects with the lowest total Evaluated Costs in Dollars per MW-month; and DSM Projects that, on the basis of the Total Resource Cost Test, are demonstrated to be cost-effective.' For the 300MW RFP, the criterion will be: 'The Ministry will select Successful Proponents starting with the lowest Proposal Price, proceeding to the one ranking second lowest, and continuing to select according to the ranking of Proposals by Proposal Price until the total RES Contract Capacity of the selected Proposals adds up to as close to 300 MW as possible, provided that this limit may be exceeded under the circumstances set forth in Section III.H.'

was sold to Brascan in 2002 and partly through leasing facilities, for example, the Bruce nuclear power plant was leased to a consortium known as Bruce Power in 2001. However, plans to privatise Hydro One failed and OPG still remains the dominant generator in the province[4]. The distribution sector, previously dominated by municipal companies was not restructured but the municipal companies were turned into 'for-profit' companies with the opportunity to privatise or part-privatise.

By November 2002, after a series of price spikes, which saw retail rates nearly double in the peak-demand summer months, the Ontario government suspended the retail market. They capped the price small consumers paid at 4.3 cents per kWh and refunded amounts paid over that price cap level. The privatisation of Hydro One was stopped. In March 2004, the price cap was raised to 4.7 cents per kWh for the first 750 kWh and 5.5 cents for energy used above that.

5. Is the investment requirement real?

A primary justification for the new reforms is the need to finance new power stations to meet growth and to replace old plants, and to finance refurbishment of some existing nuclear power stations. The proposals assume that by 2020, 18,000MW out of the 30,000MW currently in service will have to be replaced or refurbished and that demand growth will require a further 6400MW to be built. The proposals imply this is an exceptional requirement that will be difficult to finance. It is therefore important first to establish whether this requirement is real.

The installed capacity in Ontario is about 30,000MW. The largest source of generation is nuclear power, accounting for about half the capacity (15,000MW including capacity not currently in service) and, if all units were in service, these would produce much more than half the generation. The rest is divided between fossil-fuel plants (about 10,000MW) and hydro-electric plants (about 7000MW).

5.1. The nuclear plants

Ontario has three nuclear power stations, Pickering, Bruce and Darlington comprising a total of 20 units. These, especially Pickering and Bruce, have had a problematic history in the last 15 years, with eight of the units closed for six years or more.[5] Ontario Power Generation (the publicly-owned generation company spun off from Ontario Hydro in 1999) operates the Pickering and Darlington stations. Pickering A consists of four units (542MW) completed from 1971-73. These four units were out of service for a lengthy period from the mid-90s onwards. One unit (unit 4) returned to service in September 2003, and in July 2004 a decision was taken to refurbish a second (unit 1) with a view to restarting it in September 2005. The budgeted cost is C$900m. A decision on whether the other two units should be brought back into service has not been taken yet. The cost of the refurbishment has escalated from an estimated C$1.1bn to refurbish all four units and the first unit alone cost about C$1.25bn. If refurbishment is completed, it might be expected that the plants could be regarded as essentially new, with an operating life beyond 2020.

Pickering B (four units of 540MW) was completed from 1983-86 and has remained in service without the lengthy shutdowns that have affected other plants. If it is to remain in service beyond 2020, it will need a major refurbishment before then. Darlington (four units of 935MW) was completed from 1990-93 and has not suffered a long-term shutdown. It is likely the units would need to be refurbished (assuming a life-time of about 25 years before refurbishment was needed) at around 2020 to remain in service beyond then.

The Bruce station has also been problematic. The plants were built by Ontario Hydro and were then passed on to its de-integrated successor company, Ontario Power Generation. In 2001, OPG leased the station to a consortium known as Bruce Power, with the privatised British nuclear company, British Energy, as the majority shareholder with 82.4 per cent. The lease runs to 2018 with an option to extend for a further 25 years. The remainder of the stock was held by Cameco and by Bruce staff organizations - the Power Workers' Union and The Society of Energy Professionals. In February 2003, financial difficulties with its UK operations forced British Energy to sell its stake. Now Cameco and two other Canadian companies

[4] The attempt to sell Hydro One failed when an Ontario court found that the government had not given itself the legal authority to sell it. The attempt to sell several coal-fired generating plants was blocked due to environmental concerns.

[5] The units were closed as part of plan to improve performance and bring all Bruce and Pickering reactors back to operation - it was decided to shut these eight units down so that the other eight units at Pickering and Bruce could be concentrated on.

TransCanada Pipelines, of Calgary, and BPC Generation Infrastructure Trust, of Toronto (a pension fund), each owns 31.6 per cent of the shares with the staff organisations doubling their stake to 5.2 per cent.

Bruce A (four units of 904MW) was completed from 1977-79. Unit 2 was damaged in an equipment failure in 1995 and would need major repair work to bring it back into service. Unit 1 has been down since 1997 and Bruce Power is studying what measures would be necessary to bring it and unit 2 back into service. Units 3 and 4 were out of action from 1998-2003 but have now been returned to service but without major refurbishment and can only operate for another 5-8 years without further repairs. To operate beyond 2020 they will need major refurbishment. Bruce B (four units of 915MW) was completed from 1984-87 and would need major refurbishment to run beyond 2020.

The nuclear capacity available after 2020 is hard to estimate. At the lower end of the scale, only the two units at Pickering A (total capacity of about 1000MW) have a high probability of being in service while at the upper end, all existing plants could still be in service with a capacity of about 15,300MW. Decisions on refurbishment are controversial and refurbishment is costly, probably more than the cost of building new gas-fired capacity, but cheaper than new nuclear plants.

5.2. Nuclear refurbishment

The key components determining when refurbishment of the nuclear units must be undertaken if the unit is not to be retired are the fuel-containing pressure tubes. These are expected to have a life of 20-25 years. Re-tubing is technically well-established having been first done in the mid-80s. The time taken for this job will vary from unit to unit depending on what other repairs or upgrades are required, but it may be prudent to plan for an average of 18 months per unit. The job is demanding and it may also be sensible not to have more than three units under repair at any one time to ensure technical resources are not over-stretched. This means that if all the nuclear units are to be in service beyond 2020, 18 units will have to be refurbished over and above Pickering A units 1 & 4 where refurbishment is underway or completed.

In fact, if we assume a tube life of 22-23 years, decisions will have to have been taken to either close or refurbish 14 of the 18 units by about 2010. This has two important consequences. First, it means that there will be an additional plant requirement of about 2500MW to replace the output of the nuclear plants, either temporarily or permanently. Second, decisions must be taken very soon on the future of the nuclear plants, putting in place resources for refurbishment if that is the decision or permanently replacing the capacity.

5.3. Fossil plants

OPG owns approximately 9700MW of fossil fuel plants, with four stations in Southern Ontario accounting for the bulk of this. Lambton (1975MW, completed 1970), Nanticoke (3920MW, completed 1972-78), and Lakeview (1140MW, completed 1969, but slated to close April 2005) are coal-fired plants, while Lennox (2000MW) is dual oil/gas fired. The new Liberal government has pledged to close the coal-fired power plants by 2007, removing about 8000MW of generating capacity. In principle, fossil-fuel power stations of this type have an indefinite life-time: all the major items of equipment are reasonably replaceable. However, the determining factor for the life-time of such a plant is the cost of maintenance and repairs, the price of power and also the environmental acceptability of such plants. Nevertheless, by 2020, the coal plants will be about 50 years old and it seems likely that cleaner, more efficient coal-fired technology will then be available. The decision whether to retire these plants, maintain them in service or replace them with more coal plants therefore has a large political as well as economic element.

5.4. Hydro-electric plants

Ontario has a capacity of about 7000MW of hydro-electric plants. The expected life-time of hydro-electric plants is much longer than nuclear or fossil-fuel plants and most and perhaps all of this capacity can be assumed to be in service still in 2020 without huge expenditures. While a decision to build new hydro-electric plant would probably raise significant environmental issues, maintaining existing plants does not.

5.5. Demand growth

The projected growth in demand is relatively modest, a little over 1 per cent per year, and is not the main cause of the demand for new plant. Such a low demand growth rate is likely only to be possible if a very effective energy efficiency programme, the responsibility of the new Ontario Power Authority, is carried through.

5.6. Overall plant demand

The main uncertainty in the period to 2020 is policy towards life-extending the nuclear plants. If no further life-extension is carried out (but refurbished plants are allowed to continue), only 1000MW of nuclear capacity will remain, whereas if all plants are refurbished, about 15,300MW will still be in service. By 2020, all the existing conventional fossil-fired stations are likely to be retired, but all the hydro capacity should remain in service. Assuming a need for 6400MW of capacity to meet demand growth, the range of needs for new plant is about 18,000-28,000MW. So the Ontario government's forecast that about 24,000MW of new and refurbished capacity will be required in the period to 2020 seems plausible provided the assumptions on nuclear plant and coal-fired plant, and demand growth are accepted.

However, in the shorter term, if the coal-fired plants (7500MW) are shut by 2007, if the nuclear plants off-line (2900MW) now are not quickly brought back into service and if demand grows at 400MW a year (1200MW), about half of the overall plant demand will arise in the next three or four years. Capacity is now about 30,000MW and peak demand is about 25,000MW, so if we assume a 20 per cent margin is necessary to maintain secure supplies and we do not assume imports from the USA and other provinces will be available at peak times, there is little surplus plant at present. Building about 13,000MW in the period 2008-2020 (about 1000MW per year) should not prove problematic but building 3500MW a year for the next three or four years would be a severe challenge under any regime. Reliance on the availability of large-scale imports from the USA does not appear a prudent plan. It may be necessary, whatever solution is chosen for the generation market, to reconsider the coal retirements, clarify the position on nuclear refurbishment and accelerate demand-side measures to smooth the demand for new capacity.

6. What are the options for new capacity?

In all European markets where the generation sector has been opened up and new capacity built, this new capacity has been almost invariably been gas-fired except where subsidies or guarantees have been introduced and 'dashes for gas' have occurred in Britain, Spain and Italy. The reasons for this dominance of gas are the short construction times, the low construction costs, the relatively good environmental performance and the low technological risks.

However, the long-term gas resource context in Europe is very different to that of North America. Europe has a number of major gas producers, such as Norway, the Netherlands and the UK and is surrounded by regions with vast gas reserves, such as Russia and the other former Soviet countries, the North African countries, and the Middle East. More than 80 per cent of the world's gas reserves are readily accessible, from a physical point of view, to European markets. These resources are generally in countries with strong economic incentives to sell as much gas as possible. There are political issues about the security of gas supplies to Europe, but so far supplies have always been maintained despite political instability in producing countries and there is little doubt that Europe can readily access decades of gas. In North America, resources currently available are much less clearly capable of sustaining a growing demand for many decades.[6]

Of the other options, it would clearly be illogical to close the old coal plants on environmental grounds only to replace them with new coal plants. Building new nuclear plants is not attractive in a competitive market because of the high construction costs, the technological risks and the economic and physical inflexibility of the plants. Renewables and large scale hydro-electric plants are also unlikely to flourish in a competitive market without strong government backing.

If the generation market is opened, as in Europe, gas-fired plant is likely to dominate, but unlike Europe, it is far from clear that North America has the gas resource base to sustain sharply increased gas use for several decades. Until clean alternatives are well-established and clearly attractive to private investors, it would not appear an appropriate time to open the generation market up.

[6] See for example, A Weissman (2004) 'The Current Natural Gas Supply Crisis and Options for Fueling Electric Generation' North American Power Markets Conference, Toronto, Canada, January 28, 2004.

7. Will market signals be sufficient to generate the required investment?

After an initial call for tenders for about 3000MW to be allocated by a competitive process, the government's proposals appear to be based on market signals to stimulate the necessary investment. This raises two issues: are there private investors willing to invest in new generation; and, if there are, under what terms would they be willing to invest?

7.1. Are there private investors?

Four or five years ago, this question would have appeared trivial. Many US utilities, such as TXU, Reliant, Mirant, Enron, AES, AEP, Edison Mission and NRG were expanding outside the USA, and European companies, such as EDF, Endesa, Tractebel, RWE and E.ON were also looking to develop markets outside their home bases. However, experience with these international ventures has often been economically disastrous. Some of the US companies (Mirant and Enron) collapsed, while all the others are withdrawing to their home markets. The European companies, generally larger than the US companies, have scarcely done better and few if any are now looking to expand outside Europe.

It is unclear when, or even if, utilities will again begin to look at investments outside their existing markets. It may be that Canada will be regarded as a sufficiently low risk market that some of the large European and US utilities will at least contemplate investing in Ontario, but it is by no means certain. If international investors were not likely to enter at least in the short-term, that would place the burden solely on Canadian companies, such as TransAlta, TransCanada, Fortis and Atco and an assessment needs to be made to see if national sources can provide the volume of investment required efficiently. At this stage, a large number of companies both from inside and outside Canada have expressed an interest in investing in Ontario, but such expressions of interest are almost cost-free and should not be taken as an indication that real investment decisions will be forthcoming.

7.2. What terms will investors require?

Assuming that, in principle, there are investors willing to invest in power generation in Ontario, the next issue is under what terms? The Minister's statement implies that the wholesale electricity market would continue as at present. If there is something approaching a competitive market, this would make investment in new generation a risky venture. Those investing in power plants that sold into the wholesale market (merchant plants) would not know from one day to the next how much power they would sell and at what price. Investing sums in the region of C$1bn with so few guarantees would be intolerably risky or would be possible only with a large risk premium on investment that would make the power produced very expensive.

One way to reduce risk would be for a new generator to sign a power purchase agreement with a retail company. However, if the retail market is to be genuinely competitive, no retailer will be able to forecast their sales far in advance. Either the retail market would be a sham or any power purchase contract sufficiently long-term to allow the finance of a new power plant (10 years or more) would probably not be worth the paper it was written on.

Experience from the British market illustrates these points. At the end of 2003, 40 per cent of the generating capacity in Britain was owned by companies that were financially near collapse, had been repossessed by the banks that had lent money to purchase them or was for sale at distress prices. About half of this capacity was nuclear, while the rest was coal and gas-fired power plants, in the latter case, often of modern technology.

In addition, while the National Grid Company, which owns the transmission network is able to make good profits on a (regulated) real annual rate of return of 6.25 per cent, it is widely accepted that those investing in power stations apply a real discount rate of at least 15 per cent. For a power station costing about C$1/kW of installed capacity (a typical price for a modern gas-fired plant), this could add about 2c/kWh to the cost of production and much more for capital intensive options such as nuclear power.

8. What if market signals do not generate enough new capacity?

If sufficient capacity is not built simply through market signals, the Ontario Power Authority would be required to carry out some process, such as setting up competitive bidding, to commission the construction of the required new capacity. In return for the winning company agreeing to supply power at its bid price, the authority would have to sign a long-term power purchase agreement specifying the volumes that would be purchased and price paid. Dwight Duncan has been unclear on whether long-term contracts would be awarded. In February 2004, he stated long-term contracts would not be awarded, but later retracted this and said no decision had been taken. This uncertainty has meant that as of July 2004, TransAlta was not going to bid in the 2500MW RFP and Atco was undecided. In order to finance a new power plant, the developer would need a 'bankable' commitment that ensured a minimum amount of power was purchased at a specified price. It is inconceivable that a bidding company would be bound to a bid price and volume if a similarly strong agreement to purchase the power at the agreed price was not signed.

This 'back-stop' position raises two issues. First, would any company invest in generation through any mechanism other than this one? If not, the system would essentially revert to being a centrally planned one but without the flexibility of the traditional structure. Second, will it be possible for the Ontario Power Authority to identify in time when capacity would be needed? A third issue, even if there is theoretically sufficient capacity available, can there be any assurance that it will be available to generate power for Ontario rather than exporting it to the USA is covered in section 10, which covers the international trading regime.

8.1. Would Ontario Power Authority purchases come to dominate the system?

On the first issue, if the Ontario Power Authority identified a need for new capacity it would probably hold some sort of bidding contest, such as the Ontario government is holding now, to identify the cheapest option. This would reduce the investment risk to the company building the plant, but how would the power that was purchased in this way be allocated to the market? Would all retailers be required to purchase some of this power, perhaps pro rata according to their market share? The more power that was purchased in this way, the less scope there would be for competition between retailers.

As argued above, so-called merchant plants, in other words plants that buy and sell into the spot market without substantial contractual cover, would command a large risk premium on investment. Merchant plants could not compete with plants commissioned by the Ontario Power Authority, which would have fixed long-term contracts and the more power that was built under commission from the Ontario Power Authority, the less market there would be available for merchant plants to compete in. The nuclear plants are largely inflexible physically and would be base-load price-takers, in other words they would have to bid low to ensure they were dispatched and would have to accept whatever price the market generated. The hydro plants, with minimal operating costs, would easily out-compete fossil-fired stations. So the market for new merchant plants would be even more restricted.

In this situation, it seems likely that potential investors would not build merchant plants and would take the much less risky option of waiting for the Ontario Power Authority to identify plant need and competing in the contests set up by the Ontario Power Authority. Ultimately, this would mean that the system was dominated by plant built under commission from the Ontario Power Authority (and nuclear plants). This would then raise the issue of flexibility. If the plant commissioned by the Ontario Power Authority had fixed power purchase agreements, which plant would provide the flexibility necessary in an electricity system to accommodate the large daily swings in electricity demand?

8.2. Can the Ontario Power Authority identify plant need in time?

The second issue seems trivial on the face of it. In a traditional centrally planned system, it is relatively easy in principle (if not always in practice) to forecast supply and demand and identify shortages well in advance. However, in a free market, things are much less predictable. Many developers take out what are effectively 'options' on sites, applying for permissions etc, without making a full financial commitment.

In a free market, there is free exit and entry, and experience suggests neither is predictable. In order for new capacity to be brought on-line, a shortage would have to be predicted at least five years ahead to allow new plant to gain planning authorisation, for equipment to be ordered and construction to take place. Many projects that are announced are not completed or are completed much later than originally forecast.

This point is clearly illustrated by experience in Europe. At the start of 2004, 12.6GW of generation projects were fully authorised in Italy (in a system with installed capacity of about 80GW), and a further 44GW of projects had industry ministry approval.[7] In Britain, a large volume of projects has also been announced and it is difficult to forecast which plants will be built and when. It is therefore not clear how a planning authority could forecast what proportion of these projects would actually go ahead and on what time scale.

Market exit is equally unpredictable. In 2002, there was a large enough surplus of generating plant in Britain to provoke steep wholesale price reductions sufficient to lead to the financial collapse of a significant proportion of generating companies including the nuclear company, British Energy. This lead to a large scale market exit so that by summer 2003, it was necessary for the National Grid Company (the transmission system operator) to call for extra capacity to be brought on line to prevent power shortages in that winter.

Unless strong restrictions on market entry, requiring entrants to stick to a construction schedule on pain of tough penalties once approvals had been received, are imposed, and restrictions requiring existing generators to give several years notice of exit are introduced, predicting the scale and timing of capacity shortages would be impossible. Such restrictions would probably be unworkable and would certainly make a mockery of the attempts to create a 'free' wholesale market.

8.3. European experience

The Ontario reforms on new capacity shadow closely the recently revised European Union Electricity Directive[8], passed in July 2003. In this, Member States were encouraged to adopt an 'authorisation process' for new plants, in other words, there would be no planning hurdles for new power plants to pass other than the normal planning procedures for any industrial facility. However, the Commission is becoming increasingly concerned about security of supply and in paragraph 23 of the Directive, the Commission states:

> 'In the interest of security of supply, the supply/demand balance in individual Member States should be monitored, and monitoring should be followed by a report on the situation at Community level, taking account of interconnection capacity between areas. Such monitoring should be carried out sufficiently early to enable appropriate measures to be taken if security of supply is compromised.'

In the Notes[9] to the Directive, the Commission states:

> 'However, Member States should ensure the possibility to contribute to security of supply through the launching of a tendering procedure or an equivalent procedure in the event that sufficient electricity generation capacity is not built on the basis of the authorisation procedure.
>
> Member States shall ensure the monitoring of security of supply issues. Where Member States consider it appropriate they may delegate this task to the regulatory authorities referred to in Article 23(1). This monitoring shall, in particular, cover the supply/demand balance on the national market, the level of expected future demand and envisaged additional capacity being planned or under construction, and the quality and level of maintenance of the networks, as well as measures to cover peak demand and to deal with shortfalls of one or more suppliers. The competent authorities shall publish every two years, by 31 July at the latest, a report outlining the findings resulting from the monitoring of these issues, as well as any measures taken or envisaged to address them and shall forward this report to the Commission forthwith.'

The Commission does recognise the dangers of such an approach and notes:

> 'The Commission submits that the tendering procedure has the advantage of being relatively easy to organise and will ensure that investors will actually construct the capacity tendered (as opposed to the authorisation procedure where the grant of an authorisation is no guarantee that the capacity authorised will be built). However, the tendering option equally gives rise to a number of important [concerns] which should be considered by Member States:
>
> - Launching a tendering procedure constitutes an intervention on the market from the part of the authorities;
> - Such a procedure, as is the case with other interventions, distorts the investment signals that exist in the market and could lead to 'a wait for the tender to be launched' approach on the part of investors.
>
> The consequences of launching a tender in peripheral markets will tend to be more limited to the national markets. However, launching a tender in a non-peripheral Member State does not only cause an intervention on the market in

[7] Power in Europe, 1 March 2004.
[8] http://europa.eu.int/comm/energy/electricity/legislation/amending_legislation_en.htm
[9] http://europa.eu.int/comm/energy/electricity/legislation/doc/notes_for_implementation_2004/security_of_electricity_supply_en.pdf

the country in question, but might also lead to disparities on the internal market regarding Member States that rely on different measures to ensure security of supply.'

Despite its concern about market interventions, the Commission then lists a range of market interventions Member States could take to prevent capacity shortages. These include:

- Keeping capacity standby for reserve purposes. A central authority would be required to contract for reserve capacity to meet peaks;
- Capacity payments. Generators would be paid for having capacity available;
- Capacity requirements. Retail suppliers would be obliged to buy reserve capacity;
- Reliability contracts. The transmission system operator is required to buy 'call options' from generators;
- Capacity subscriptions. Each customer must buy a capacity fuse from a generator that limits his or her consumption;
- Long-term contracts. Retail suppliers would be obliged to enter long-term contracts with generators.

There is no space to review each of these possibilities individually, all have serious shortcomings, but it is clear that eight years after the first EU Electricity Directive was passed, the European Commission is increasingly concerned that the market will not ensure supply and demand balance and that strong non-market interventions are needed to ensure supply and demand do balance.

9. How would the new market differ from the earlier market?

The key difference between the new proposals and the old, failed market appears to be the role of the Ontario Power Authority in ensuring generation capacity adequacy. Other changes seem to amount to no more than renaming agencies and moving responsibilities from one agency to another. On retail competition, medium and large consumers would again have free choice while small consumers could choose between a regulated rate and buying from independent retailers. However, all consumers would ultimately be exposed to the wholesale market price. Small consumers would pay a rate based on monopoly charges, contracted generation costs and a forecast of market prices. If the forecast proves wrong, it seems likely that the companies would be able to recover any under-forecasting from consumers in the following year.

10. The free trade context

The proposals cannot be considered just as internal to the province of Ontario; the wider North American Free Trade Agreement (NAFTA), established in 1994 and the World Trade Organisation's General Agreement on Trade in Services (GATS) have to be considered.[10] The issues surrounding GATS are complex and the failure of the Cancun summit in September 2003 has delayed the implementation of GATS, but there is little question of the GATS proposals being withdrawn.

10.1. The GATS process

The World Trade Organisation (WTO) replaced the GATT organisation on free trade agreements in 1994. Ministerial Conferences are the top-most decision-making body under the WTO and these conferences must take place at least once every two years. The Cancun meeting was the most recent Ministerial Conference. The Marrakech agreement came at the end of the 'Uruguay Round' of trade negotiations (1986-94) under which, for the first time, the agenda was broadened to include commodities other than 'goods' under trade agreements. The General Agreement on Trade in Services (GATS) was part of the Marrakech Agreement.

Signatories to the Marrakech Agreement (including Canada) are committed under GATS to progressively open their service sectors to international entry and liberalisation. A new 'round' of negotiations on services

[10] For a fuller account of the issues surrounding NAFTA and GATS, and the electricity industry, see, S Shrybman (2001) 'A legal opinion concerning the impact of international trade disciplines on the privatization and restructuring of Ontario's electricity sector' Sack Goldblatt Mitchell, Ottawa, Marjorie Griffin Cohen, 'From Public Good to Private Exploitation: GATS and the Restructuring of Canadian Electrical Utilities,' Canadian American Public Policy, no 28, December 2001, pp. 1-79, Marjorie Griffin Cohen "Imperialist Regulation: US Electricity Market Designs and their Problems for Canada and Mexico" Forthcoming in Ricardo Grinspun, ed. "The Slippery Slope: Canada, Free Trade and Deep Integration in North America" (Montreal/Kingston: McGill/Queens Press, 2004), S Thomas, I R Rajepakse, & J Gunasekara (2003) 'Turning off the lights: GATS and the threat to community electricity' Intermediate Technology Development Group, Bourton on Dunsmore, and Pierre-Olivier Pineau 'Electricity Services in the GATS and the FTAA', Energy Studies Review, vol. 12 (2), Spring 2004.

started in 2000 and under the Doha agreement of 2001 (the Ministerial Conference prior to Cancun), is scheduled to end on January 1, 2005.

Given that energy is such a major service both in terms of its economic significance and also its importance to consumers, there is surprisingly little reference to energy in the GATS classification of services. Under the GATS agreement, 12 categories of service are identified and within each of these broad categories, there are a number of subcategories, which are broken down even further. In all, there are several hundred subcategories. Energy appears only once amongst these subcategories as ‘services incidental to energy distribution’, which is one of 20 sectors within the ‘Other business services’ category of ‘business services’. ‘Services incidental to energy distribution’ appears a rather limited set of activities, implying consultancy activities. However, reference to a more detailed classification (the United National Provisional Central Product Classification) reveals that it includes core distribution and transmission activities. Indeed, the USA and the EU are proposing that electricity generation be included in this category as a service under GATS. Classifying it as a ‘good’ would bring it under the general GATT agreement. Negotiations are now underway to define energy as a separate sector and resolve how electricity generation should be classified.

Under the GATS, service sectors are to be opened under a system of ‘request and offer’. Members are required to ‘offer’ to open service sectors up and were required to make an initial ‘offer’ to open up activities by March 31 2003. Members can make a ‘request’ to another member to open a sector and the GATS agreement stated initial requests should be made by June 30, 2002. The response to the initial timetable was poor, and by June 12, 2003, only 26 members of the WTO had made offers. The response on requests is not easy to estimate because these requests are made bilaterally with no requirement to inform the WTO. A hint of the nature of the request process was given when the EU’s list of requests was leaked to the public. Requests were made to 109 members of the WTO in twelve sectors, including energy. In about 40 per cent of the cases (46), the EU requested an opening of the energy sector. Compared to most other sectors, especially, for example, telecoms (106 out of 109), the number of requests to open up the energy sector was lower.

Commitments made under GATS must be taken very seriously. Once a country has made a commitment to open a sector, there is little scope to withdraw it. The GATS process is being carried out in a very secretive way. Industrialised countries have not made their requests public, and developing country governments are unwilling to open up the process to public debate, despite the far-reaching consequences of a decision to open up an activity. For example, the heading of the EU request to each country states ‘Member States are requested to ensure that this text is not made publicly available and is treated as a restricted document’.

The WTO protests that it is no part of the GATS agenda to force countries to liberalise and privatise its service industries, but this is disingenuous given that written into the GATS is a commitment by WTO member governments to progressively liberalise trade in services. The two major trading blocs, the USA and the EU, are clearly using the GATS negotiations to pressure countries to privatise and liberalise their energy sectors. In its communication to the WTO’s Council for Trade in Services of March 2003, the EU stated[11]:

> ‘The recent experiences of liberalisation in some energy sectors and the already well established presence of third country suppliers in other sectors like oil and gas, are showing the way for a win-win opening up of national markets to competition and to foreign suppliers.’

A US communication to the Council for Trade in Services (December 2000) stated:

> ‘Competitive conditions in a nation’s energy services markets enhance the competitiveness of domestic energy consumers as well as incentives for foreign investors to invest in both energy services and energy-consuming sectors. They also can benefit residential consumers and social services, as well as employment, through the beneficial impact on energy-dependent services and manufacturing sectors.’

So far, it does not appear that Canada has made any commitments on electricity to the WTO.

[11] http://www.wto.org/english/tratop_e/serv_e/s_negs_e.htm

10.2. NAFTA

The provisions of NAFTA on services are similar to those required under GATS, but potentially more powerful.[12] Whereas under GATS, the national government is required to make a specific commitment to open a sector before its rules can be invoked by those seeking access to that sector, under NAFTA, once the sector is open, NAFTA rules apply without the need for an explicit government commitment. Of particular concern under NAFTA are provisions that prohibit import and export controls, and all forms of border price regulation. Thus if there is a shortage of power in Ontario, the government is prohibited from taking measures to restrict exports.

As with GATS, NAFTA does not by itself prescribe privatisation and liberalisation, but once the door is open, it is effectively impossible to go back. Foreign companies are entitled to 'national treatment' under NAFTA, in other words, they must be treated at least as well as national companies. However, if Canadian provinces choose to retain a publicly owned integrated structure, there are no provisions under NAFTA that would make it change.

10.3. Overall impact

NAFTA and GATS mean that any efforts by provincial authorities to plan the electricity system, for example by ensuring that supply and demand balance, cannot be effective. Under GATS and NAFTA reforms are irreversible and if the reforms fail, it will be impossible for the provincial government to take control of the sector again and re-introduce a planned approach.

If 'merchant plants' are built, trade agreements will mean that the Ontario Power Authority cannot assume that plant sited in Ontario will be available to Ontario. If the price of power is higher in connected markets, there will be no way to prevent such plants exporting their output, so even though there might nominally be enough capacity in Ontario, there can be no guarantee it will be available for Ontario. If as seems likely, no new merchant plants are built and the market is dominated by plants contracted to the Ontario Power Authority, these will be likely to be available to Ontario, although the existing hydro and nuclear plants may choose not to be contracted and 'play' the market. At best, this would lead to very high prices as and at worst, power shortages.

The precise implications of NAFTA and particularly GATS are far from clear. At present, at least until it is clear that any reforms to the electricity industry have been successful, the most prudent policy for the Canadian government would seem to be to make no commitments under GATS and to invoke any protections available under NAFTA for the integrated publicly owned provincial systems.

11. What will be the impact on prices

There is approximately 3400MW of nuclear plant shut down that must be either refurbished or replaced in the next few years, while Bruce A units 3 & 4, Pickering B and Bruce B may only have a few years of operation left before refurbishment is required. The costs of refurbishing the five closed nuclear units is likely to be of the order C$5bn, significantly more than the cost of building new gas plants, which might be expected to cost about C$700-800/kW (C$2.5bn). If 7500MW of coal plant is retired and replaced with the option with lowest construction costs, gas-fired plant, this will cost an additional C$5bn, and perhaps more if other options are chosen. The decisions on nuclear refurbishment and coal plant retirement are political ones that should be taken by the Ontario people. The decisions on nuclear are urgent.

If the coal plant is retired, there will be a need for in excess of C$10bn investment in the next 3-4 years and, however this investment is carried out, this could result in higher prices for consumers. To the extent that old power plants, especially the coal plants, for which the capital costs have long been written off will be replaced by new plants that must repay their construction costs, it seems likely this will place upward pressure on prices. However, new plant, especially gas-fired plant is likely to be more technically efficient this may counterbalance the impact of the recovery of the investment cost of the new plant.

[12] For an analysis of the impact of NAFTA on the electricity sector, see G Horlick, C Schuchhardt & H Mann (2001) 'NAFTA provisions and the electricity sector' Commission for Environmental Cooperation, Background paper, Montreal. http://www.cec.org/files/PDF/nfta5-final_EN.pdf

The issue to be determined is which method of operating the sector will meet this investment need at lowest cost to the consumer. It is likely that a competitive solution will put pressure on companies to minimise their costs. However, competition cannot exist without risk and there is always a cost if the market is asked to bear risk, most clearly in the form of a risk premium on investment. For a capital intensive industry such as electricity the likely doubling or more of the required rate of return on capital required will significantly raise costs and it seems implausible that efficiency savings will pay for this huge additional cost.

However, as argued above, it seems likely that most plant will be built under commission from the Ontario Power Authority and will be given long-term contracts. For foreign investors, there will be some currency risk and there will also be a 'technological' risk. If the plant is not built to time and cost, or if it is not as reliable as forecast, there will be substantial extra costs that cannot be recovered from consumers and, again, there will be a risk premium on investment. There will also be the bidding risk that the cost of making the bid (see below) will be lost if the bid is unsuccessful. Of course this will be an incentive to complete plants to time and cost and run them efficiently but whether the improved performance this might bring will pay for the extra risk is far from clear.

The final issue is whether private companies can invest more cheaply than publicly owned companies. Generally, government owned companies have a very high credit rating and their cost of borrowing is correspondingly low and probably lower than for private companies. There is often an assumption that privately owned companies are more efficient than publicly owned companies. There is no general evidence to support this in the electricity sector and, for example, the price of power provided by publicly owned companies in the USA is generally somewhat lower than the cost of power from investor-owned utilities. Clearly, OPG has suffered from cost control problems with the refurbishment of Pickering but there is no evidence that these problems cannot be dealt with by better management of the company by the provincial authorities. Of course, if OPG is prevented from bidding, any improvements in its efficiency will have no impact on the cost of constructing new capacity.

12. Will the call for tenders work?

The new proposals will stand or fall on the success of the current call for tenders. This is looking for 300MW of renewable capacity and 2500MW of 'clean' projects to be in service by mid-2007 for demand side bids and 2009 for new generation. OPG is specifically excluded from bidding for the renewable capacity and cannot be the lead organisation on a 'clean' bid.[13]

12.1. New 'clean' generation

Generation plants must be 'clean' plants of more than 5MW. However, natural gas plants, which do emit acid and greenhouse gases, are allowed and while emissions are much less than for a coal-fired plant, the designation 'clean' is somewhat dubious. In practice, it seems likely, if experience in other liberalised markets is anything to go by, that the cheapest bids will be combined cycle gas-fired plants, perhaps with some use of waste heat. The winning bids must expect to be in service by June 2009 and contracts will run until December 31, 2027. The contract guarantees to cover the bid prices from the bidder through what is effectively a 'contract for differences'. In other words, if the income from the market is below the bid price, the Ontario Power Authority pays the bidder the difference and vice versa. Note that the operating costs include gas price indexation so the prices are not fixed. If the gas price goes up, the cost of power will also go up. Under this form of contract, the bidder takes no commercial risk; the price they receive is guaranteed whatever the market conditions.

12.2. Demand reduction (DR)

Demand reduction measures, which would come into operation when the market price exceeded a specified level, must be in operation by end 2007, must be available for at least five years and must reduce demand by at least 5MW. Again, there must be some question about their designation as 'clean'. While reducing peaks may be economically worthwhile, if the proposals merely shift demand away from peak to another lower

[13] The official documentation on the 2500MW RFP states: 'Ontario Power Generation Inc. (OPG) will be instructed by its shareholder that it shall not directly participate as a sole Proponent in the 2,500 MW RFP. OPG may be permitted to participate as a member of a Proponent Team, provided that the Proponent is not controlled by OPG.

demand period, this may simply reduce the loading on a peaking fossil-fuel plant and increase the loading on a mid-load fossil-fuel plant. The payment in the first year of operation will be C$200/MWh. Thereafter, payments will be made under a form of contracts for differences.

12.3. Demand side management (DSM)

As with demand reduction, proposals must be for at least 5MW and be available for at least five years. Since these will lead to real savings in use of fossil fuel use, it is appropriate to designate these as 'clean' options. Projects must have a payback of more than three years (presumably, projects with a shorter payback might be expected not to need any support) and the contract will reduce the payback time to three years.

12.4. Green generation

Renewable projects must be between 0.5-100MW and must be in service by end 2007. They will be awarded a 20 year contract paying the bid price with some scope for additional incentive payments.

12.5. What proportion of projects will be completed?

Clearly, the 2500MW and 300MW of capacity requested will be the upper limit of the amount of capacity built under the current call for tenders and some of the plant will not be built. There is a difficult balance to be struck between requiring strong assurances that plant that is selected is built and not placing unreasonable demands on plant developers. Similar processes in Britain produced impressive results in terms of prices bid, but a significant proportion of plants chosen were not actually completed.

The Ontario government's RFP documentation does list guarantees bidders must make, including securities of between C$250,000 and C$1,000,000, as well as the technical and commercial credentials required of the company. These upfront costs will of course be factored into the bids and will be paid by consumers. A company making a bid will, unless it is very certain it will win the contest, be unwilling to risk large sums of money obtaining all planning consents and tying up financial backing from financiers. If these prove more difficult or expensive than anticipated, it may prove cheaper to surrender the security than proceed with a loss-making project. Getting the right level of incentives so that a high proportion of projects selected actually proceed to completion is likely to take some tuning and is unlikely to be right first time, so even with the RFP process, there is some level of uncertainty about how much plant will actually be built. Note that in Britain, a similar process to allow construction of renewable plant saw the completion rate actually fall over a period of 8 years and five contests from just over 90 per cent to not much more than 10 per cent.[14]

12.6. Evaluation

Bidding contests of this type can be a valuable way of testing the market to see whether innovative lower cost options, not considered by the main companies, are available. However, they are by no means certain to deliver the required volume of plant. The more competitive the process, the higher the failure rate is likely to be. The demand side measures are relatively short-term (five years) in comparison with the time-frame under consideration here and while demand reduction is often economically and environmentally attractive, this will have to be an ongoing process.

The decision not to allow, or to restrict OPG from participating in these contests seems a risky one. While there clearly is a risk that OPG will dominate the bidding and perhaps choke off private participation, OPG clearly does have financial strength and would also be expected to have a very high completion rate for projects. If later it becomes clear that private investors with attractive projects are being inhibited from bidding, it might be appropriate to restrict OPG then, but the priority now is to maximise the probability that the necessary investment is carried out.

It is worth noting also that for generation projects, the lead time from launch of process to plant coming on line is more than five years, so the Ontario Power Authority will have to be able to forecast available capacity and demand six years and more in advance.

[14] Hartnell, G., 2003. Renewable Energy Development 1990–2003. RPA, London.

13. Retail competition

In Ontario, before restructuring, there were a large number of distribution companies operating the local network and retailing power to final consumers. Most were publicly owned by municipalities with Ontario Hydro supplying directly those not covered by local distribution companies. Under the 2002 reforms, the municipal utilities became for-profit companies, although ownership could remain with the local authorities and these companies were required to continue to supply residential consumers that did not choose a new supplier under regulated 'standard supply service' terms that included indexing to the wholesale market. Retail competition was suspended in November 2002. The new proposals are basically the same as the old ones with small consumers able to choose a regulated tariff with pass-through of wholesale electricity prices.

In some respects, retail competition should have little economic impact on consumers. The network charges should be standard, while if the wholesale market is working well, the wholesale cost of power should be about the same to all retailers. This just leaves the retailers' own costs to compete over. For very large consumers of electricity, even a small percentage cut in electricity charges may be worth having.[15]

Before retail competition was introduced for small consumers in Britain, retailers' costs (billing, meter reading) accounted for less than 10 per cent of a typical small consumer's bill. However, in a competitive system, there are major additional costs for the retailer. These include advertising, marketing, the technical cost of switching a customer from one company to another – in Britain, the cost of simply transferring a consumer from one supplier to another is in excess of C$100. The activity of buying electricity on the wholesale market is also a major job requiring skilled commodity traders. Now in Britain, the retailer's costs, excluding metering, make up about 30 per cent of a typical residential consumer's bill. It seems highly unlikely that the 'magic' of competition will be strong enough to pay for these extra costs.

There are additional problems of equity between classes of consumer. It is clear that medium and large consumers will have the incentive and the skills to exploit the market to the maximum changing supplier frequently to ensure they get the cheapest power. However, small consumers do not have the skills and many seem uncomfortable 'experimenting' with such a vital purchase. Switching rates amongst small consumers are generally low in the countries that do have retail competition and in Britain, there is evidence that there are a small number 'serial' switchers and a large number who will never switch. The 'switchers' probably cause retailers large losses with profits well below the cost of acquisition, while the non-switchers are largely insensitive to costs. This is a recipe for exploitation.

In Britain, when the retail supply market was only open for medium and large consumers, the electricity retailers systematically allocated their cheapest wholesale purchases to the captive market with the consequence that small consumers paid 30 per cent more for the generation element of their bill (generation then made up about half the total bill). Things got worse for small consumers after retail competition was introduced for them in 1998/99. After then, the companies were effectively free to charge small consumers whatever the market would bear. In the period 1999-2002, the wholesale electricity price was reported to have fallen by about 40 per cent in Britain, yet small consumers actually paid 5 per cent more for their generation and large consumers only saw a reduction of about 20 per cent.

Within residential consumers, there may well be discrimination. Competing retailers will tend to target their marketing at the largest consumers. Poor consumers who have difficulty in paying their bill will not be attractive. In Britain, those who pay their bill by Direct Debit (a fixed sum taken directly from their bank account) are offered lower rates than those the poorest consumers who pay via pre-payment meters (more than 15 per cent of consumers in Britain pay for their electricity in this way).

The new proposals for Ontario seem closest to the former position in Britain when small consumers could not choose their supplier and whose tariffs were fully regulated. As noted above, these regulated tariffs did not protect them from being exploited by the companies. International experience suggests consumers will stick with their existing supplier. Unless there is strict regulation, the retailers will have little alternative but to allocate their cheapest power to the large consumers to protect their market share there, leaving small consumers with the high cost power.

[15] For large consumers, the economic benefits may come from shifting demand away from expensive periods as much as from a cheaper kWh price.

One other factor that should not be ignored is any locational effect. Britain is a small, densely populated country where very few consumers live far from demand centres. If a significant number of consumers in Ontario live in remote locations that are more expensive to supply, there is a risk that in a competitive market, such consumers would not be attractive to competing suppliers and would receive a poor and/or expensive service. If the political judgement is that electricity is a vital service that should be available to all no broadly comparable terms, regulatory measures will be necessary to ensure remotely situated consumers are not disadvantaged.

14. Conclusions

Ontario is faced with a need to make major investments in its electricity sector in the next 3-4 years to replace or refurbish old plant and to meet demand growth. The solution proposed by the current Ontario government has much in common with that of the previous administration, relying on a wholesale power market, retail competition and on private sector investment in new generating capacity. Such a recipe has a mixed and often poor track record in other countries and other provinces of Canada. It therefore seems an unduly risky strategy to abandon a structure, the vertically integrated, publicly owned monopoly company, with a long track record of successfully meeting demand. One attempt at reform failed within months of its introduction and the new system inherits many of its characteristics, including a wholesale market, retail competition and free entry to new generators. The major difference is the creation of the Ontario Power Authority to monitor supply and demand and with the powers to commission the construction of new capacity if it foresees a shortage. However, it seems unlikely that the Ontario Power Authority will be able to foresee shortages accurately, nor will it be able to act in time and there is also a serious risk that too low a proportion of the capacity it commissions will actually be completed.

It is recommended that the Ontario government takes the following steps:

14.1. Wholesale competition

The illusion that wholesale competition can be created should be abandoned. Experience in other countries suggests that wholesale electricity markets only work well (as measured by downward pressure on prices) when there is surplus capacity. For example, the NordPool system that covers the Nordic markets seems to have operated smoothly for nearly a decade but it has had the advantage of a surplus of capacity. It has not so far stimulated any significant investment in new generating capacity and, unless it does soon, a shortage of capacity may emerge.[16]

Wholesale markets do not seem to stimulate new investment and in systems with a major investment need, such as California and Brazil, attempts to introduce wholesale competition have been disastrous. In all wholesale markets, the risk of market manipulation seems high and in the UK, for a decade after the reforms were introduced, the wholesale price was kept high by the behaviour of a few large generators. These high prices ensured there was ample incentive for new generators to enter and maintain surplus capacity. Now the wholesale market in Britain is largely bypassed as the generation companies now own all the retailers and generate power for their own consumers, not the market.

Under the present proposals for Ontario, it seems likely that few if any plants will be built to compete in the market and, in the words of the European Commission, companies will adopt ‘a wait for the tender to be launched’ approach. This would result in a semi-planned system, but without the advantage of being able to control entry and exit. Without this ability to control entry and exit, balancing supply and demand will be very difficult.

A more suitable system would be perhaps to adopt a ‘single buyer’ model. Under this, a public agency, such as the proposed Ontario Power Authority would be given the responsibility to procure the province’s power needs and ensure that the province had access to enough capacity to meet its own needs. It could use a variety of instruments such as power purchase contracts of varying durations, and contests to build new

[16] A large new nuclear plant was ordered in 2004 in Finland, but this is a very specific case. It will be owned largely by an association of industrial consumers that operates largely out of the market supplying only its members and is not-for-profit.

capacity to ensure power was purchased at the lowest cost consistent with supply security, environmental protection and any other relevant strategic considerations.

14.2. Gas resources

A review of the adequacy of the gas resources available to Canada and, Ontario in particular, needs to be undertaken if it is expected that a significant proportion of new capacity built will be gas-fired.

14.3. International trade agreements

Clarification is urgently needed on what measures are allowed under the NAFTA and GATS trade regimes. If, as seems likely, it becomes clear that untested reforms such as those proposed by the Ontario government will be effectively irreversible under these agreements, this reinforces the warning that untested reforms, especially those that are likely to result in privatisation and the end of sector planning, should not be undertaken. The Government of Ontario should lobby the Federal government to ensure that no commitments are made under GATS and all possible protections from the free trade model under NAFTA are taken up.

14.4. Retail competition

Attempts to introduce retail competition should be abandoned. Experience elsewhere suggests that large consumers will profit but only at the expense of small consumers if large consumers are given choice. If retail competition is extended to all consumers, the poorest consumers will be at risk of having to pay the highest prices.

14.5. The role of the publicly-owned companies

The government's proposals prevent Ontario Power Generation from participating strongly in the construction of new generating plants. Given the huge investment needs, the high likelihood that plant being built by OPG would be completed and the doubts about the appetite of foreign investors to make investments in the electricity sector outside their home markets, this seems an unnecessarily restrictive strategy.

14.6. Privatisation

Regardless of the merits of privatisation, the lack of international investors makes any attempt to privatise or break up companies such as OPG and Hydro One unwise. The selling price would probably be far below the real value of the businesses. Until and unless the privatised liberalised electricity industry model is much better proven, efforts should be concentrated on improving the management (both internal and by the Ontario government) of the publicly owned assets so that they are able to make investments and operate existing assets efficiently. This would include ensuring that the publicly-owned companies have access to sufficient investment funds to meet their investment needs.

14.7. The coal and nuclear power plants

Important decisions need to be taken urgently on the future of coal-fired and nuclear generating plants in Ontario. While there is flexibility in the closure dates of the coal-fired plants, there is much less flexibility with the nuclear plants, which must either be retired or refurbished when their pressure tubes no longer meet the standards required by the safety authorities. These decisions are for the Ontario people to take through clear, democratic processes.

Annex Liberalisation in Europe

The European Union Electricity Directive of 2003 (2003/54/EC)[17] seems to prescribe complete liberalisation of Member States' electricity industries, requiring full retail competition, legal separation of network companies from companies generating or selling electricity, and appointment of a sector regulator. The Directive, agreed by the European Parliament and the Council of the European Union on July 2003 required that Member States transpose its provisions into national law by July 1 2004. In practice, of the 25 Member States, only the Netherlands and Slovenia met this dead-line, although Denmark, Hungary and Lithuania are reported to be close to completing the process. None of the five largest Member States met the deadline. Other countries may pass the necessary laws later in 2004 while some will not complete the legislation until 2005. The European Commission will also have to consider whether these law changes do actually represent the requirements of the Directive. The Table shows that amongst the five largest Member States, only Britain appears to be complying fully (if not legislatively) with the letter and the spirit of the Directive.

While Germany introduced retail competition in 1998, in practice very few small consumers have switched. The two dominant companies, RWE and E.ON own a large part of the network and are required only to grant access to third-party companies through Negotiated Third Party Access (NTPA), rather than Regulated Third Party Access (RTPA), which ensures third-party companies have access to the network at published, non-discriminatory prices. No sector regulator has been appointed and plans to introduce one, with legal powers, have now been delayed until 2005. The two largest companies own or control a large number of subsidiaries and their dominance of generation and retail is much fuller than the figures in the Table imply.

The French system is dominated by the nationally-owned utility, Electricité de France (EDF), which still owns the network and has about 80 per cent of the generation and retail markets. Retail competition for small consumers is not expected until 2007, the latest date allowed under the Directive. In Italy, retail competition and a wholesale electricity market have only recently been introduced and ENEL, the part privatised national electric utility still has a strong hold on generation and retail. Spain, like Germany is essentially a duopoly with Endesa and Iberdrola controlling about 80 per cent of the wholesale and retail markets.

By contrast, Britain seems to have complied fully, although closer examination shows the markets are far from perfect. The industry is dominated by three large European companies (EDF, RWE and E.ON) and three much weaker British companies. All six companies are generators and retailers so the wholesale market is largely bypassed. More than 95 per cent of wholesale electricity sales are through 'self-dealing' or long-term entirely confidential contracts. The power exchange (UKPX) accounts typically for about 0.5 per cent of wholesale trades. Britain is one of the few countries that have introduced retail competition where annual switching rates are above 10 per cent. However, of the consumers that have switched, most have opted to buy electricity as a package with gas from the dominant gas retailer, Centrica. This is despite the fact that for most small consumers, the Centrica package represents usually the most expensive offer in the market. It seems that consumers are either buying on grounds other than price, or are not able to evaluate the competing deals effectively.

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[17] For the full text, see http://europa.eu.int/servlet/portail/RenderServlet?search=DocNumber&lg=en&nb_docs=25&domain=Legislation&coll=&in_force=NO&an_doc=2003&nu_doc=54&type_doc=Directive

Table Liberalisation of electricity markets in Europe

	UK	Germany	France	Italy	Spain
% market open (year for 100%)	100 (1998)	100 (1998)	37 (2007)	66 (2007)	100 (2003)
Transmission System Operator unbundling	Ownership	Legal	Management	Ownership	Ownership
Distribution System Operator unbundling	Legal	Accounts	Accounts	Legal	Legal
Network access	RTPA	NTPA	RTPA	RTPA	RTPA
Regulator staff (budget €m)	300 (57)	None: 2005?	96 (12)	104 (19)	187 (21)
Largest generators' market share	16	23	78	43	37
Largest 3 generators' market share	37	61	86	72	79
Power exchange	1990 Pool, 2001 UKPX	2000 EEX	21.10.2003 Powernext	31.3.2004 IPEX	1998 OMEL
Dominant balancing generator	No	Yes	Yes	Yes	No
Switching 2002: Large consumers	15	20	15	15	20
Switching 2002: Small/domestic	12	5	-	-	-
Retailers with more than 5% of market	7	3	1	4	4
Largest 3 retailers' market share	62	53	91	72	88
Market assessment	6 strong integrated companies: E.ON, RWE, EDF, Scottish & Southern, Scottish Power, Centrica	E.ON, RWE have about 80% of generation and retail. Vattenfall and EDF control most of rest	EDF (integrated) totally dominant	ENEL has about 50% of generation and retail. Municipalities in retail, EDF, Endesa and Electrabel in generation	Endesa and Iberdrola have about 80% of generation and retail. Hidrocantabrico and Union Fenosa control most of rest

Source: Directorate General Transport and Energy Working Paper (2004) 'Third benchmarking report on the implementation of the internal electricity and gas market' Commission of the European Communities