

Ontario's Electricity Supply Industry after the Restructuring: An Economic and Environmental Impact Analysis

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Abstract

The Government of Ontario set out to restructure Ontario's electricity industry in the late 1990s. Through the enactment of the *Energy Competition Act, 1998* and the subsequent *Electricity Restructuring Act, 2004*, Ontario's electricity sector changed from a traditional "public utility" model (i.e. a state-owned vertically-integrated utility) to a "hybrid model", which includes both regulated and competitive aspects.

This thesis paper seeks to answer the question: from an economic and environmental perspective, how have Ontario's electricity consumers been impacted by changes resulting from the restructuring and post-restructuring policies of government? To answer this question, the prices paid for electricity service (commodity, transmission, and distribution) prior to the restructuring are compared to the prices paid for the same service after the restructuring. The analysis reveals that prices are rising more rapidly in the post-restructuring era. The question becomes what changes in the sector are driving the price increases and are consumers benefitting from these changes? This paper evaluates the changes to the sector resulting from the restructuring, and from other post-restructuring government policies, in a qualitative manner to determine whether consumers are receiving any benefit from these changes. The analysis highlights that some changes have impacted customers positively (i.e. shift to more environmentally-friendly energy sources, conservation, distributor amalgamation, etc.) and other changes simply added costs with no real benefits to consumers (i.e. facilitation of a competitive market for electricity supply, retail electricity markets, etc.).

Disclaimer Statement

The information contained in this paper represents the views of the author, and in no way reflects the Ontario Energy Board's position or opinion.

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Part A

1. Introduction

1.1 Background

Traditionally, the electricity supply industry was regarded as a natural monopoly, where the high capital costs associated with constructing an electricity generation, transmission, distribution and system control infrastructure acted as a natural barrier to entry. There are certain aspects of an electricity supply system that are not inherently monopolistic (generation and retail supply). However, these two crucial functions in an electricity supply system have traditionally been bundled with the naturally monopolistic functions to create a single vertically-integrated, publicly-owned corporation that was responsible for effectively managing all the functions associated with the production, transmission and distribution of electricity.¹

Ontario's electricity sector, prior to industry restructuring, followed the traditional model. Ontario Hydro, a crown corporation owned by the Ontario Government, was a vertically-integrated electric utility responsible for the generation, transmission and distribution² of electricity to Ontario's electricity consumers. Ontario Hydro largely controlled its own business. It set its own rates, made decisions regarding capital expansion, and determined the best way forward for Ontario's electricity sector.

The restructuring of Ontario's electricity supply industry began in 1998 with the introduction of the *Energy Competition Act, 1998*. The *Energy Competition Act* unbundled Ontario Hydro into five companies. The five companies were: the Independent Market Operator (later renamed the Independent Electricity System Operator), Hydro One Networks Inc., Ontario Power Generation, the Electrical Safety

¹ Yajima, 1997: 1-2.

² Ontario Hydro distributed electricity to a large number of retail customers that lived outside the service areas of municipal distributors.

Authority, and the Ontario Electricity Financial Corporation. Each company had complete control over a certain aspect of the electricity sector.³

Ontario's electricity supply industry began operating competitively under a voluntary pool market on May 1st, 2002. This means that generators had the option to either sell their electricity into the pool (based on a competitive bidding process) or they could establish bilateral contracts with their customers and have power wheeled through the system directly to their customers (based on a contracted price). The functions of transmission and distribution were still regulated by the government.

The competitive electricity market opening in May 2002 coincided with the hottest summer in 50 years and electricity demand hit record highs. In another unfortunate coincidence, the demand increase corresponded with a lack of supply as nuclear plants were still offline due to retrofitting programs and there were also unforeseen problems with some coal-fired generators. The outcome of high demand and low supply was massive rate shock. The public reacted immediately to the exploding energy costs and the government responded by setting a price cap of 4.3 cents / kilowatt hour ("kWh") and also provided rebates for the period when the price was above the 4.3 cents / kWh level. The government also froze electricity distribution and transmission rates.⁴

The *Electricity Restructuring Act, 2004* was developed and passed on the basis of the perceived failures in the first restructuring. The Electricity Restructuring Act was passed by McGuinty's Liberals after the Liberal election win in late 2003.

The *Electricity Restructuring Act, 2004* "instituted the hybrid model for Ontario's electricity sector".⁵ The act intended to take a balanced policy approach by amalgamating the features of both a competitive and regulated electricity sector. The competitive aspect of the model is the continued operation of a wholesale market system. The prices of the wholesale electricity are based on frequent auctions between

³ Winfield, 2012: 103.

⁴ Treblicock and Hrab, 2006: 425-426.

⁵ Electricity Market Investment Group, 2006: 2.

generators who wish to supply electricity into the pool. The regulated aspect of the electricity supply sector is the Regulated Price Plan, which establishes the price of electricity for consumers that purchase electricity from their local distribution company.

The hybrid system established by the *Electricity Restructuring Act, 2004* still exists today. Currently, the price paid for electricity by the end consumer is comprised of the following three components: commodity, transmission and distribution. For residential and commercial customers, the commodity price is based on the Regulated Price Plan⁶, and is either a two-tiered or time-of-use price both of which are set by the Ontario Energy Board (the “OEB”).⁷ Distribution and transmission prices are also regulated and set by the OEB. There are currently 77 electricity distribution companies in the province and 5 transmission companies.⁸

1.2 Literature Review

A number of researchers have studied the electricity sector reforms that have occurred in jurisdictions all across the world.

In regard to Ontario's electricity sector, some researchers looked at the political context of the restructuring, seeking to understand why the restructuring happened. For example, Swift and Stewart (2004) provides a detailed account of the rationales for restructuring.⁹ Winfield (2012) also discusses some of the rationales for restructuring in his book setting out the process undertaken to implement the restructuring. Winfield (2012) also discusses the post-restructuring policy direction of government.¹⁰ These

⁶ The Regulated Price Plan price is set based on a forecast of actual costs and the price paid by consumers for electricity is meant to recover the actual costs of generation.

⁷ The two-tiered price prevails in situations where the customer does not have a smart meter and the time-of-use price prevails when the customer does have a smart meter (and its service provider has implemented time-of-use pricing).

⁸ Ontario Energy Board, 2012a: 1.

⁹ Swift and Stewart, 2004.

¹⁰ Winfield, 2012.

books provide a detailed account of the purpose and process of the restructuring (and some post-restructuring changes) in Ontario's electricity sector but do not specifically analyze the results of the restructuring and post-restructuring government policies. In doing so, they contribute to the historical understanding of the reasons why the sector was restructured and how it was restructured.

Other researchers looked at Ontario's electricity sector restructuring itself and analyzed the problems and outcomes. For example, Trebilcock and Hrab (2006) provided an in-depth analysis of the implementation problems associated with Ontario's electricity restructuring. The paper largely focused on the problems that arose from the initial restructuring (prior to the release of the *Electricity Restructuring Act, 2004*).¹¹ Amongst other things, the paper concluded that Ontario's electricity restructuring resulted in an increase in electricity-related debt, higher prices for consumers and halted long-term system planning (due to uncertainty related to the restructuring). In addition, the authors identify an important lesson: restructuring policies need to directly address political implications (i.e. public backlash) in order to ensure success (and avoid expensive policy reversals).¹²

Zareipour, Canizares and Bhattacharya (2007) analyzed the operational aspects of Ontario's electricity market and provide insights regarding the outcomes over the first four years of market operation. A main conclusion was that price volatility in Ontario's market was higher than other restructured markets and that this volatility was caused by the real-time nature of Ontario's market (as opposed to the day-ahead nature of the comparative markets used in the study). The authors also concluded that the physical electricity system is not sufficiently considered in the process of clearing the market price.¹³

¹¹ The paper noted that, at the time of writing, it was too early to determine whether the new regulatory regime under the *Electricity Restructuring Act, 2004* reflects an improvement over the initial restructuring regime (under the *Energy Competition Act, 1998*).

¹² Trebilcock and Hrab, 2006.

¹³ Zareipour, Canizares, and Bhattacharya, 2007.

The two papers discussed above were written shortly after the electricity sector restructuring occurred in Ontario. These papers look at issues related to the competitive market design (and surrounding political issues in the case of Trebilcock and Hrab) in the period immediately after restructuring. They contribute to knowledge base in terms of an understanding of the immediate issues and outcomes of the electricity sector restructuring in Ontario.

In more recent papers, researchers looked at the impact of government policies on electricity prices in Ontario. Dewees (2012) explained the reasons that residential electricity prices in Ontario increased over the 2000-2010 period and forecasted price changes over the 2010-2015 period (and linked the forecast to specific price drivers and related government policies). The paper concluded that supply mix changes (new generation sources being more expensive than historical sources of generation), infrastructure renewal, costs associated with operating a competitive market for electricity, and taxes are the main reasons for the price increases experienced by residential customers from 2000-2010. The paper also concluded that the forecasted price increases over the 2010-2015 period will be largely caused by the addition of renewable generation capacity.¹⁴

In another more current study, Sharp (2012) provided a forecast of electricity prices over the 2011-2016 period for a number of categories of electricity consumers. The report utilized a wide-range of price drivers (generation additions, existing generation, conservation, transmission, distribution, and wholesale market service charges) in developing the electricity price forecast. The paper concludes that the majority of forecasted price increases will be related to the commodity component of the electricity bill with smaller, although still substantial, increases on the other components of the bill.¹⁵

The papers by Dewees and Sharp both provide an analysis of electricity prices in Ontario and discuss the reasons that prices have increased (and are expected to

¹⁴ Dewees, 2012.

¹⁵ Sharp, 2012.

increase in the future). These papers contribute to the literature on Ontario's electricity restructuring by providing a better understanding of the impact that different government policies have had (and are expected to have) on electricity prices in Ontario. These two papers are, in some ways, conceptually similar to my paper. However, there are some key differences. The time periods over which the studies were completed, the methodology used for creating the electricity pricing time series, and the granularity of the price driver analysis are notably different. As will be discussed in the next subsection, this paper provides information that is incremental to the analysis completed in the noted papers and fills certain gaps in the existing literature.

A number of researchers have also studied the impact that restructuring policies have had on electricity prices in California and other US jurisdictions. For example, Borenstein (2002) discussed the issues that caused price volatility and price increases in the California electricity sector immediately after restructuring and provided some potential solutions to those problems. The paper concluded that, in the short-term, real-time retail electricity pricing and contracting for generation capacity could help to control wholesale electricity prices in California. However, in the long-term, more significant structural changes would need to occur in order to improve the competitive electricity market.¹⁶ In a more recent study, Borenstein and Bushnell (2014) reviewed the reasons and objectives for restructuring in US jurisdictions, discussed the outcomes of the restructurings that occurred, and provided an analysis of future challenges facing the US electricity sector.¹⁷ These papers contribute to knowledge base on electricity sector restructuring in terms of a better understanding of the immediate problems that arose in California's restructuring and the long-term outcomes of electricity sector restructuring in US jurisdictions. It is important to understand the outcomes of electricity sector reforms in other jurisdictions to better contextualize the issues that arose in Ontario's own sector restructuring.

¹⁶ Borenstein, 2002.

¹⁷ Borenstein and Bushnell, 2014.

Overall, there have been numerous studies that have analyzed electricity sector restructurings and the impact that these reforms (and other policy changes) have had on electricity prices.¹⁸ My paper falls within this broad base of literature and, as will be discussed in greater detail in the next sub-section, fills certain gaps in the existing knowledge base.

1.3 Research Questions

The main research question that I answer in this paper is:

From an economic and environmental perspective, how have Ontario's electricity consumers been impacted by changes resulting from the restructuring and post-restructuring policies of government?

I will discuss a number of topics in order to answer this research question. First, I will provide an analysis of competition in electricity generation and customer choice in retail supply. Second, I will provide an analysis of the change in Ontario's generation supply mix and conservation activities from before the restructuring to 2012. Finally, I will provide an analysis of Ontario's electricity prices over the 1983-2012 period and individually analyze all of the major price drivers that have impacted electricity prices over the post-restructuring period.

As discussed, some researchers have touched on topics similar to those that I examined as part of the analysis undertaken to answer my main research question. This paper does, however, provide incremental information that is not available in the existing literature. The incremental information and analysis provided in my paper is discussed below.

I have generated a time series of pricing data that extends from the early 1980s to 2012 (a 30-year period). The pricing information reflects the actual average price for

¹⁸ The above does not reflect an exhaustive list of all the research that has been completed on the topic. There are also numerous other jurisdictions that have been studied (the UK, Australia, New Zealand, Texas, Argentina, etc.), which are not discussed here.

electricity (and includes all costs associated with electricity service). This pricing dataset was developed for the purposes of this paper and is not available in the existing literature on the topic. I developed this new electricity pricing dataset, as opposed to using pricing data that was previously available, as I believe that using an average price, as opposed to a price applicable to a specific class of customers, is ideal as it avoids any pricing distortions that could potentially arise in the cost allocation process and allows for a more effective analysis of electricity pricing over time. In addition, by using an expanded timeframe for pricing analysis (30-years) a comprehensive understanding of the changes in Ontario's electricity prices can be provided.

This paper also includes statistical analysis which examines the correlation between the restructuring (and certain post-restructuring) policies of government and the changes in electricity prices over time. This type of statistical analysis has not been previously published in the literature as it relates to electricity prices in Ontario.

My paper also identifies all of the major changes that arose from the restructuring and post-restructuring policies of government, which have impacted electricity prices. The changes that I identify to have impacted electricity prices are viewed through a financial and environmental lens (as applicable) to determine whether consumers are benefitting from the changes. In total, I identify and analyze, in detail, 17 price drivers that have impacted the price of electricity in Ontario over the post-restructuring period. While other researchers have studied a limited number of price drivers that have impacted electricity prices, the level of detail provided in this paper is not available elsewhere in the literature.

Overall, the analysis undertaken to answer my main research question fills gaps in the existing body of literature on the electricity sector restructuring in Ontario.

In order to provide sufficient context for my research, I begin the paper by providing a brief discussion of the rationales, the objectives, and the process of restructuring Ontario's electricity supply industry. To this end, I will answer the following background research questions.

What were the reasons for Ontario's electricity sector restructuring?

To answer this question, I will analyze the rationale for the restructuring. The analysis in this section will review the work done by other researchers on the topic and the rationales set out in the Government's white paper titled, "Direction for Change: Charting a Course for Competitive Electricity and Jobs in Ontario" (the "Government's White Paper"). This analysis will canvass the following topics:

- (a) The Mike Harris government's ideological beliefs
- (b) The perceived unsatisfactory performance of Ontario Hydro

What were the objectives of the restructuring (as originally set out by the government)?

The analysis in this section is based on the MacDonald Committee's report and the Government's White Paper. In both of those documents, the government set out the proposed objectives of the restructuring.

How has the electricity sector evolved (1998-2012)?

In response to this question, I will discuss the relevant legislation that led up to the restructuring. The discussion will also include a listing of all of the major milestones and policy changes that occurred prior to the restructuring, during the restructuring and in the post-restructuring period.

For the most part, the information provided in this paper in response to the background research questions is available in the existing literature related to the electricity sector restructuring. Between Swift and Stewart (2002), Treblicock and Hrab (2006), Winfield (2012), and the primary source documents (i.e. the MacDonald Committee Report and the Government's White Paper), the information discussed in this paper in relation to the background research questions is largely available in the existing literature.

1.4 Summary of Principal Findings

The following provides a brief summary of the principal findings that are set out in this paper.

- The “all-in” electricity price and the distribution price increased more rapidly in the post-restructuring period (post-1998) when compared to the pre-restructuring period (pre-1998). This finding is supported by the statistical analysis undertaken and discussed in the paper.
- The pricing analysis performed in this paper was hindered by a lack of available data for the 1998-2005 period. This made the pricing evaluation more difficult. Data gathering and recording functions should be maintained during transition periods after policy implementation (and were not in the case of Ontario’s electricity sector restructuring).
- There were a large number of factors (price drivers) that impacted the price for electricity (commodity, transmission, and distribution) over the post-restructuring period. The price increases experienced during the post-restructuring period can be linked to three main causes: (1) restructuring-related government policies; (2) post-restructuring government policies; and (3) real cost pressure.
- The restructuring-related government policies were largely designed to facilitate a competitive market for electricity supply and to offer customers choice in retail electricity supply. Consumers were, generally, impacted negatively by the restructuring-related policies of government. Electricity consumers continue to pay incremental costs associated with the competitive market design even after the government essentially abandoned competition for electricity supply. In addition, facilitating retail supply options for consumers applied pressure on electricity prices during the post-restructuring period and consumers derive little benefit from the retail option.
- The post-restructuring government policies were largely designed to make Ontario’s electricity sector more environmentally-friendly. Significant costs were incurred to “green” Ontario’s electricity sector. However, the implementation of these policies has largely resulted in a significant improvement in the environmental performance of Ontario’s electricity sector which benefits all of Ontario’s citizens.

- The price drivers that arose from the post-restructuring environmental policies of government should be considered, analytically, separate from the price drivers associated with the restructuring-related government policies as the government's environmental policies would likely have been implemented irrespective of the sector restructuring.
- Overall, both the restructuring-related and the post-restructuring policies of government applied significant pressure on electricity prices during the post-restructuring period. Consumers were generally impacted negatively by the restructuring-related government policies and more positively by the post-restructuring-related government policies.

1.5 Interdisciplinarity of Thesis Topic

My thesis topic falls within the broad academic discourse of policy analysis. Policy analysis is inherently an interdisciplinary area of study. Concepts from the academic disciplines of political science, public administration and economics are commonly involved in any study of the policy decisions of government.

A single government policy could impact citizens in numerous ways (i.e. socially, economically, environmentally, etc.). In order to understand the full impact of policy decisions (and to understand why policy decisions were made) an integrated interdisciplinary approach must be utilized.

In regard to the government policies studied in my thesis paper, citizens in Ontario were largely impacted economically and environmentally. Therefore, as is necessary in all studies of policy analysis, my paper uses an integrated interdisciplinary approach to understand the impact of the government's electricity sector reforms. My analysis relies on concepts, techniques and perspectives from disciplines including: political science, public administration, economics, and environmental studies.

While techniques and perspectives from each of the above disciplines were considered, they were not used in a delineated fashion where specific methodologies from each

were strictly followed. Instead, the approach that I use to study Ontario's electricity sector restructuring is more holistic and integrated in nature. Using an integrated interdisciplinary approach allowed me to provide a comprehensive understanding of why the electricity sector restructuring occurred, how it was implemented, and how consumers were impacted both economically and environmentally from the sector restructuring.

Overall, my thesis entails a case study on Ontario's electricity sector restructuring through the lens of policy analysis. The thesis fulfills the requirements for the M.A. in Interdisciplinary Studies program at York University as it uses an integrated interdisciplinary approach for policy analysis (which touches on a number of disciplines as set out above). It also fills a void in the existing literature.

Part B

2. Rationales for the Electricity Sector Restructuring

2.1 Introduction

A number of researchers have looked at the rationales for Ontario's electricity sector restructuring. In addition, the Government's White Paper, which set out the high-level plan for restructuring, provides some insight on the government's rationale for moving forward with its restructuring plan.

The key rationales for restructuring include:

(a) Harris government's ideological beliefs

The Harris Government believed that the private sector operates more efficiently and that by moving to a competitive electricity sector, market forces would apply downward pressure on electricity prices.

(b) Perception that Ontario Hydro was inefficient

The Harris Government also believed that Ontario Hydro was not operating efficiently. At the time, the government thought that by splitting up Ontario Hydro's business and selling off its assets to the private sector, the electricity sector could be better managed.

2.2 Harris Government's Ideological Beliefs

The Harris Government came to power at a time that jurisdictions all over the world were looking at ways to restructure their electricity sectors. As noted in the Government's White Paper, "other jurisdictions are restructuring rapidly, setting examples, and positioning themselves to compete more effectively for investment and

jobs. Ontario risks falling behind.”¹⁹ Generally, the central argument leading governments to seek free-market reforms in electricity supply is that privatization results in lower purchasing costs for the consumer with a lower reliance on governmental regulation.²⁰

The Harris government ran on a platform known as the Common Sense Revolution (“CSR”), which advocated for reducing taxes, cutting programs, reducing red tape and government control in numerous areas. Specifically, the government stated that it was seeking to cut taxes by 30%, cut non-priority spending (which the government defined as all areas other than health, education and law enforcement) by 20%, reduce the workforce of the provincial government by 15% and reduce regulatory burden. A key principle underlying the CSR platform was that the private sector could do things better and more cost effectively.²¹

Interestingly, the CSR platform actually said very little about the electricity sector. However, given the government’s ideological views that the private sector could do things more efficiently and cost-effectively than the public sector, and the fact that other jurisdictions were seeking electricity sector reforms, Ontario’s electricity sector eventually became a target for reform.²² The government believed that unbundling the Ontario Hydro monopoly and selling off its assets to the private sector would lead to efficiencies and lower electricity prices.²³

The ideological views of the Harris government would likely have been enough to cause the restructuring of the electricity sector, but the government also referred to the unsatisfactory performance of Ontario Hydro as a rationale for the restructuring.

¹⁹ Ontario Government, 1997: 1.

²⁰ Pollitt, 1995: 1.

²¹ Winfield, 2012: 92-93.

²² Ibid: 102-103.

²³ Swift and Stewart, 2004: 127.

2.3 Unsatisfactory Performance of Ontario Hydro

In the Government's White Paper on electricity restructuring, the government focused a lot of attention to Ontario Hydro's unsatisfactory business record as a rationale for its proposed restructuring.

Ontario Hydro played a prominent role in the economic development of Ontario. The government noted that historically Ontario Hydro was universally recognised as a well-run and responsible organization. However, the government stated that in the 1990's Ontario Hydro's performance had faltered.

The government pointed to increased electricity prices for Ontario consumers during the early 1990s, the poor performance of Ontario Hydro's nuclear assets, high wages and excess staffing as some of the key concerns related to Ontario Hydro. The issue of Ontario Hydro's debt was also raised. The government noted that Ontario Hydro was struggling with over \$30 billion in debt and that interest payments on the debt amounted to over 30% of total revenues. The government also discussed the declining availability of Ontario Hydro's nuclear capacity. The amount of nuclear capacity available at any given time had declined from the early 1980s to the early 1990s.²⁴

Daniels and Trebilcock, in their paper titled, "The Future of Ontario Hydro: A Review of Structural and Regulatory Options" provided a detailed analysis of the problems facing Ontario Hydro in the early 1990s.

The authors noted in the early 1990s, electricity prices were rising rapidly at a time where the province was facing a severe recession. As a result of the public uproar arising from the electricity rate increases, Ontario Hydro implemented a price freeze on its rates.

In 1993, Ontario Hydro was forced to incur restructuring charges of over \$3.6 billion associated with employee severance costs, write-downs related to assets which were recorded at values in excess of market value, and plant closure costs. In the same year,

²⁴ Ontario Government, 1997: 5-8.

Ontario Hydro reduced its full-time work force by approximately 24%.

Another problem raised in their paper was Ontario Hydro's debt level. In the absence of provincial government guarantees on the company's debt, a Royal Bank of Canada Dominion Securities report concluded that Ontario Hydro would have difficulty meeting the requirements for a BB rating from Standards and Poors given its 1995 financial results.

The authors also raised the issue of Ontario Hydro's excess generation capacity. In 1989, the difference between Ontario Hydro's installed capacity and maximum peak demand was approximately 28.1%. By 1993, that difference grew to about 64.8%. This compares to an average Canadian installed capacity vs. maximum peak demand margin of 38%.

Daniels and Trebilcock noted that the problems faced by Ontario Hydro in the early 1990s were largely caused by the following factors:

- (a) Over-estimation of future demand;
- (b) Over-expansion (and related borrowings) related to its nuclear facilities in the 1970s and 1980s;
- (c) Substantial cost over-runs and poor performance of its nuclear facilities;
- (d) Actual reduced demand due to:
 - i. Adoption of conservation measures;
 - ii. Severe recession in the early 1990s (which immediately reduced electricity demand);
 - iii. Ontario's move from a manufacturing and industrial based economy (which was energy intensive) to a more knowledge based economy (which is less energy intensive);
 - iv. Reduced prices for substitute energy sources (mainly natural gas), which allows customers to more easily use substitute other energy sources for heating and some industrial purposes.²⁵

²⁵ Daniels and Trebilcock, 1996: 4-6.

Effectively, in the early 1990s, Ontario Hydro was holding a massive amount of debt due to the expansion of its generation capacity. It borrowed significant capital to finance its nuclear expansion and its nuclear assets did not perform as well as expected. In addition, electricity demand was falling across the province and Ontario Hydro could not recover any revenue shortfalls caused by declines in sales through increased rates (as it agreed to maintain rate increases to levels below the Consumer Price Index - or “CPI”). Therefore, Ontario Hydro’s debt levels continued to climb and the government’s perception of the company diminished over the 1990s.

The Government’s White Paper largely linked Ontario Hydro’s poor performance in the early 1990s to the monopolistic operation of the electricity sector. The government noted that electricity monopolies cause higher prices, excessive debt, poor priority setting, and bureaucratic inefficiency. The government’s proposed solution was simple: open the market and introduce competition.²⁶

2.4 Conclusion

Historically, Ontario Hydro had a strong performance record. It owned and operated a relatively low-cost electricity system and was considered a well-managed company. However, in the early 1990s a number of factors came together which resulted in significant rate increases for Ontario electricity consumers, increased the debt carried by Ontario Hydro and tarnished Ontario Hydro’s reputation.

All of these problems amounted to making Ontario’s electricity sector a target for reform. Ontario Hydro was no longer viewed by the government as a well-run company. This perception combined with the Harris’ government belief that the private sector could do things better, resulted in the Harris government undertaking a restructuring of Ontario’s electricity sector. It was the government’s goal to sell off Ontario Hydro’s generation and transmission assets to private corporations and create a more market-based electricity sector.

²⁶ Ontario Government, 1997: 8.

3. Objectives of the Electricity Sector Restructuring

3.1 Introduction

In November 1995, the provincial government authorized the appointment of an advisory committee to study and assess options for establishing a competitive electricity sector in Ontario. This committee was known as the “MacDonald Committee.” The MacDonald Committee released its report titled “A Framework for Competition: The Report of the Advisory Committee on Competition in Ontario’s Electricity System to the Ontario Minister of Environment and Energy” in May 1996, which set out the committee’s advice for restructuring Ontario’s electricity supply industry. Among other things, the report identified the Terms of Reference for the MacDonald Committee’s study and a number of objectives, established through public consultations that guided the committee in the development of its recommendations for restructuring Ontario’s electricity sector. The Government’s White Paper, released a year after the MacDonald report, set out the government’s objectives with regard to the electricity sector restructuring.

It is important to understand the goals of a given policy in order to analyze whether the policy initiative was successful.

3.2 Objectives of Restructuring: MacDonald Committee Report

The MacDonald Committee was provided with a Terms of Reference by the government to guide its work on the development of recommendations for restructuring Ontario’s electricity sector.

The Terms of Reference included the government’s objectives, with regard to the restructuring, that were to guide the MacDonald Committee. The government’s objectives were described as follows: “[t]he Government of Ontario is committed to upholding the objectives of sustainable affordable electricity rates, enhancing provincial

competitiveness, preserving financial soundness and safeguarding Ontario's quality of life."²⁷

In adhering to these objectives, the Terms of Reference outlined the issues to be considered by the MacDonald Committee in making its recommendations. These issues included:

- Affordable electricity rates for all classes of customers;
- Achievement of greater economic efficiency;
- Power system reliability;
- Economic competitiveness and regional economic impacts;
- Implications for public finance including public sector indebtedness and provincial/municipal government revenues;
- First Nation and aboriginal issues;
- Electricity trade and security;
- Arrangements for nuclear power;
- Local accountability; and
- Sustainable development.²⁸

As part of its mandate, the MacDonald Committee was to hold public consultations to hear the perspectives of interested citizens on the advisory work that it was doing for the provincial government. Through those consultations, the MacDonald Committee heard a wide range of views, which were summarized in its report.

The report noted that a common theme arose in the submissions it heard from interested parties. While there was a great drive to reduce electricity rates, parties submitted that achieving that goal should not threaten a number of other important issues related to the electricity sector. For example, financial concerns should not overshadow the importance of maintaining the safety and reliability of Ontario's electricity system. Other objectives raised by parties included the following:

²⁷ MacDonald Committee, 1996: 34.

²⁸ Ibid: 135.

- Ensuring equitable sharing of the benefits of a restructured electricity sector across regions and rate classes;
- Minimizing environmental impacts;
- Establishing a set of market rules for parties accessing the competitive electricity market to ensure fairness; and
- Preserving the financial soundness of the province.

In developing its plan for Ontario's electricity sector restructuring, the MacDonald Committee attempted to address the objectives of the government, as set out in the Terms of Reference, while addressing the concerns of the interested parties that provided comments to the committee in the course of its advisory work.

The MacDonald Committee stated that any plan that it would propose for the restructuring of the electricity sector must somehow balance the objectives, which were sometimes competing, of a wide range of interested parties.²⁹

3.3 Objectives of Restructuring: Government White Paper

Subsequent to the release of the MacDonald Committee's report, the government released its White Paper on electricity restructuring. The Government's White Paper noted that, in developing its proposal for Ontario's electricity industry restructuring, the government took into consideration the recommendations of the MacDonald Committee and the positions provided by interested parties to the committee during the public consultation process.

In the Government's White Paper, the government set out its objectives for the electricity sector restructuring which did not vary significantly from those it provided to the MacDonald Committee in the initial Terms of Reference that launched the committee's work.

The following are the key objectives discussed by the government in the White Paper.

²⁹ Ibid: 34-36.

The government was looking to reduce electricity prices through competition. The government stated that a competitive market, with fair rules and vigilant regulation, would ensure that prices are as low as possible. Competitive market forces would ensure that prices reflect both supply and demand conditions, and prices will be driven to the lowest possible level, while maintaining a high standard, of service, as customers shop for the cheapest available power.³⁰

This leads into the government's next objective for the restructuring. The government argued that a competitive market would give individuals and businesses greater choice. Customers would be able to choose their own electricity supplier and this would encourage greater product and service innovation and price discipline on electricity providers.³¹

The government sought to enhance the reliability and safety of Ontario's electricity sector. The government stated that it was committed to introducing competition in the electricity sector in a manner that does not compromise the safety or reliability of Ontario's electrical power system.³²

Amalgamation of small municipal electricity utilities ("MEUs") was another objective. The government believed that amalgamating the distributors in the province would lead to efficiencies in the distribution sector. At the time of restructuring, there were over 300 MEUs operating in the province, some serving less than 100 customers.³³

The final objective of the restructuring was to reduce the outstanding debt of Ontario Hydro. A part of the restructuring was the establishment of certain mechanisms to reduce OH's debt in a fair and equitable manner over a number of years.³⁴

³⁰ Ontario Government, 1997: 11.

³¹ Ibid.

³² Ibid: 11-12.

³³ Ibid: 12.

³⁴ Ibid: 13.

3.4 Conclusion

The government's objectives for the electricity sector restructuring, as set out in its White Paper, were to reduce electricity prices through competition; allow for customer choice in electricity supply; enhance the safety and reliability of the electrical power system; gain efficiencies in electricity distribution through the amalgamation of MEUs; and reduce the debt associated with Ontario's electricity supply industry. The objectives did not evolve significantly from the initial Terms of Reference provided to the MacDonald Committee to the release of the Government's White Paper.

4. The Process of Restructuring (and Post-Restructuring Changes)

4.1 Introduction

In the following section, I will provide the major milestone of Ontario's electricity restructuring and post-restructuring changes. This section will provide the necessary context to understand the changes that occurred in Ontario's electricity sector.

4.2 Timeline of Important Events (1995-2012)

The below figure sets out a timeline of important events (i.e. legislation, reports, milestones, etc.) that are relevant to Ontario's electricity sector restructuring and post-restructuring changes. These events are discussed in greater detail in the sub-sections that follow.

Figure 1 – Timeline of Important Events – Ontario’s Electricity Sector Restructuring (and Post-Restructuring Changes)

Event	Date
Harris Progressive Conservative Government Elected	1995
MacDonald Committee Report	1996
Government White Paper on Electricity Restructuring	1997
<i>Energy Competition Act</i>	1998
Hydro One Networks Privatization Blocked	April 2002
Market Opening	May 2002
<i>Electricity Pricing, Conservation and Supply Act</i>	December 2002
McGuinty Liberal Government Elected	2003
<i>Electricity Restructuring Act</i>	2004
Ontario Power Authority Established	2004
<i>Green Energy and Green Economy Act</i>	2009
<i>Energy Consumer Protection Act</i>	May 2010
Transition to Harmonized Sales Tax	July 2010
Ontario Clean Energy Benefit	2011

4.3 Ontario’s Electricity Sector - Pre-Restructuring

Ontario Hydro, a crown corporation owned by the Ontario Government, was a vertically-integrated electric utility responsible for the generation, transmission and distribution³⁵ of electricity to Ontario’s electricity consumers. It also had responsibility for the system operation and system planning functions. The Government of Ontario had guaranteed

³⁵ Ontario Hydro distributed electricity to a large number of retail customers that lived outside the service areas of municipal distributors.

Ontario Hydro's debt and was responsible for appointing its Board of Directors.³⁶

Ontario Hydro was responsible for procuring electricity supply for all customers in the Province. Ontario's electricity demand was almost entirely supplied by assets owned and operated by Ontario Hydro. Prior to restructuring, Ontario Hydro had installed capacity of approximately 31,000 megawatts ("MW").³⁷ ³⁸ In the final full year of its operation as a vertically-integrated crown corporation, Ontario Hydro generated approximately 139 terawatt hours ("TWh") of electricity.³⁹ It also held long-term contracts with a number of non-utility generators ("NUGs")⁴⁰ which supplied a small portion of Ontario's overall electricity demand. Ontario's electricity system was, and still is, directly tied into the electricity systems of Quebec, New York State and other neighbouring jurisdictions. This allows for electricity imports and exports to these jurisdictions.⁴¹

Ontario Hydro also had the responsibility for transmitting electricity across the province. In 1998, it owned and operated approximately 29,000 kilometres ("km") of transmission lines and associated infrastructure.⁴² Transmission lines are high-voltage lines that are used to transport electricity from the generation stations to the local areas where the electricity is to be consumed. In the case of Ontario Hydro, it would transmit electricity directly to some large volume customers, to its own retail customers which were served by distribution assets owned and operated by Ontario Hydro, and to MEUs⁴³ (which

³⁶ Daniels and Trebilcock, 1996: 2.

³⁷ This generation capacity was comprised of 69 hydro-electric generation stations, 3 nuclear generation facilities, and 6 fossil-fueled stations.

³⁸ Ontario Hydro, 1999: 5.

³⁹ Ibid: 1.

⁴⁰ NUGs are privately-owned generation facilities. The NUGs referred to in this paper are located in Ontario.

⁴¹ Independent Electricity System Operator, 2013a.

⁴² Ontario Hydro, 1999: 5.

⁴³ Prior to restructuring, there were over 300 MEUs operating in the province.

would then distribute the electricity to their own customers). In all cases, transformer stations, owned by Ontario Hydro, by large industrial customers, or by the MEUs would reduce the voltage of the electricity coming off transmission lines to levels that could be transported on distribution lines for the ultimate use by energy consumers.

Ontario Hydro also operated a large retail distribution business. Customers that were not served by an MEU, mostly in rural areas, were served by Ontario Hydro. It owned and operated 174,700 km of distribution lines immediately prior to its demerger.⁴⁴

Ontario Hydro, under the *Power Corporations Act*, was required to provide “power at cost.” It was expected to pass on the costs of running its operations (generation, transmission and distribution) onto electricity customers with no markup. Ontario Hydro set electricity rates for the customers that it served directly, the wholesale price of electricity (including transmission) for the supply that was sold to the MEUs, and also regulated the rates charged for distribution services by the MEUs.^{45 46} In 1993, in response to public opposition to the rate increases that were implemented throughout the early 1990s, the government required Ontario Hydro to freeze its electricity rates.⁴⁷

The provincial government exerted control over Ontario Hydro through its ability to issue policy directives (which were developed in consultation with Ontario Hydro’s Board of Directors), to the corporation. Policy directives were considered binding on Ontario Hydro. In addition, every three years a Memorandum of Understanding between Ontario Hydro and the Ministry of Energy was developed. The Memorandum of Understanding established the accountability and reporting requirements which governed Ontario Hydro’s relationship with the Ministry and the Government. The OEB was responsible for reviewing the rates set by Ontario Hydro. However, the OEB’s powers were limited to making recommendations to Ontario Hydro and the Ministry of Energy. The OEB’s

⁴⁴ Ibid.

⁴⁵ Daniels and Treblicock, 1996: 3-4.

⁴⁶ Prior to restructuring, customers paid a bundled rate for electricity. The rate included all the costs associated with the supply of electricity (commodity, transmission and distribution).

⁴⁷ Ibid: 4.

recommendations were not binding.⁴⁸

Ontario Hydro, nearing the end of 1990's and prior to restructuring, was one of the largest electric utilities in North America. Until the unbundling of the corporation in early 1999, Ontario Hydro directly served almost 1 million retail customers (largely in rural areas), over 100 large industrial customers, and 255 municipal distribution companies (who served approximately 3 million customers).⁴⁹

In summary, Ontario Hydro was a vertically-integrated, crown corporation responsible for serving Ontario's electricity consumers. It was the producer, transmitter, distributor, system planner, and system operator of Ontario's electricity sector. Ontario Hydro largely controlled its own business. It set its own rates, made decisions regarding capital expansion, and determined the best way forward for Ontario's electricity sector. However, the government did have some mechanisms by which it could exert control over the corporation; most importantly the ability to appoint Ontario Hydro's Board of Directors.

4.4 Ontario's Electricity Sector: Lead-up to Restructuring

The beginning of Ontario's electricity supply industry restructuring can be traced back to the Harris Government's provincial election win in 1995. As noted previously, the Harris Government believed that the private sector could do things better and more cost effectively than the public sector. As such, the government eventually targeted the electricity sector for reform.

In late 1995, the Harris Government established the MacDonald Committee to study the potentials for restructuring the electricity supply industry in Ontario. In May 1996, the MacDonald Committee released its report and made over 50 recommendations regarding the restructuring of Ontario's electricity sector. Essentially, the MacDonald

⁴⁸ Ibid: 3-4.

⁴⁹ Ontario Hydro, Final Annual Report (1999): 1.

Committee suggested to the government that wholesale and retail competition be implemented for electricity supply in Ontario.⁵⁰

In support of this goal, the MacDonald Committee recommended that Ontario's Hydro monopoly on electricity generation should be eliminated and its generation assets should be separated and established as competing generators. Moreover, Ontario's electricity generators must be sufficiently separated to prevent any one company from exercising market dominance. Private equity should be introduced in the ownership of generation assets in order to enhance the introduction of competitive forces in Ontario's electricity sector. In addition, the MacDonald Committee recommended that all electricity generators should be able to compete, on equal terms, to supply electricity to Ontario consumers. To enable this, it was also suggested that non-discriminatory access to Ontario's transmission grid be made available.⁵¹

With regard to Ontario's transmission system, the MacDonald Committee recommended that the existing transmission assets of Ontario Hydro should be transferred to an independent "Transmission Grid Company," which would be responsible for managing and maintaining Ontario's transmission grid.⁵²

The recommendations associated with the distribution function of Ontario's electricity supply industry were based on two principles. First, Ontario Hydro's distribution business should be absorbed into the local distribution systems; and second, there should be fewer distribution utilities operating in the province.⁵³

Finally, the MacDonald Committee made a number of recommendations with regard to the legislative and regulatory framework that should be applicable to Ontario's electricity sector. Among other matters, the committee recommended new legislation should be enacted to replace the *Power Corporations Act* and that amendments be made to other

⁵⁰ MacDonald Committee, 1996: iii, 37.

⁵¹ Ibid: iv-v, 51, 56-64.

⁵² Ibid: iv, 52-53.

⁵³ Ibid: v-vi, 72-73, 77.

existing acts as necessary. In addition, it was recommended that the Ontario Energy Board be tasked with the responsibility of regulating the electricity industry in Ontario.⁵⁴

The MacDonald Committee stated that implementing the recommendations it set out in its report would lead to electricity rates that are lower than those that could be expected under the existing monopoly system.⁵⁵

In November 1997, a year after the MacDonald Committee report was released, the government released its White Paper on electricity sector restructuring. The Government's White Paper noted that in developing its plan for electricity sector restructuring it accepted the general direction recommended by the MacDonald Committee.⁵⁶

The Government determined that full wholesale and retail competition would be introduced to Ontario's electricity sector. All electricity generators would be able to participate in the market and customers would be given the option of choosing their electricity supplier.⁵⁷

The government set out a plan for the full separation of monopoly operations from competitive businesses in the electricity sector. Having noted that the functions of transmission and distribution are naturally monopolistic, it was determined that those functions would be regulated by the Ontario Energy Board.⁵⁸

The government stated that the OEB would be granted, through legislation, the powers necessary to fulfill its new function as the regulator of the province's electricity sector.⁵⁹ The government stated that the monopolistic functions must be regulated in a manner

⁵⁴ Ibid: vii, 97, 100.

⁵⁵ Ibid: viii.

⁵⁶ Ontario Government, 1997: 15.

⁵⁷ Ibid: 16.

⁵⁸ Ibid: 18.

⁵⁹ The OEB was already responsible for the regulation of Ontario's natural gas sector.

that ensures fair and equitable access and minimizes issues associated with cross-subsidization.⁶⁰

In accordance with its plan for the separation of the monopoly functions (transmission and distribution – the “wires” functions) from the competitive functions (generation and retail supply) of the electricity sector, the government called for the demerger of Ontario Hydro into 3 separate companies:

- The Independent Market Operator would run the electricity market exchange, dispatch power, and arrange financial settlements between buyers and sellers. In addition, it would also be responsible for forecasting supply requirements.
- Ontario Electricity Generation Corporation would take ownership of Ontario Hydro’s generation assets and would have a mandate to maximize the value of those assets.
- Ontario Electric Services Company would be granted ownership of Ontario Hydro’s transmission and distribution assets.⁶¹

The Government’s White Paper also set out its expectations with regard to the electricity distribution sector. The government stated that it expects that mergers of the MEUs begin to occur on a voluntary basis in order to achieve economic efficiencies in the sector.⁶²

Finally, the government focused significant attention on methods for dealing with the “stranded debt” of Ontario Hydro.⁶³ The government noted that stranded debt could be dealt with in three ways: (1) finding new efficiencies in savings through improved operations of the successor companies of Ontario Hydro; (2) using tax revenues collected from businesses operating in the electricity sector to pay down the stranded

⁶⁰ Ibid: 19.

⁶¹ Ibid: 17-18.

⁶² Ibid: 20.

⁶³ The government defined the stranded debt as any debt that Ontario Hydro could not service as a commercial entity in the competitive market.

debt; and (3) establishing a mechanism whereby electricity consumers would directly pay off the stranded debt overtime. The government, at the time of issuing the White Paper, had not determined how to best address the stranded debt; instead it stated that it is too early to take a position on a specific recovery mechanism.⁶⁴

Overall, the White Paper generally followed the recommendations set out by the MacDonald Committee. The government set out its high-level plan for restructuring Ontario's electricity supply industry which was premised on introducing competition into electricity generation and offering customer choice in retail supply.

After the release of the Government's White Paper, the Market Design Committee ("MDC") was established in early 1998 and issued its Final Report in early 1999.⁶⁵ The MDC's task was to develop, in accordance with the policy direction set out in the Government's White Paper, the necessary rules and protocols for the implementation and operation of a competitive electricity market in Ontario.⁶⁶

The MDC provided its recommendations to government, which the government considered when developing the *Energy Competition Act, 1998* and eventually when structuring the competitive electricity market in Ontario before market opening.

The MDC's Final Report included recommendations associated with: the governance structure for the Independent Market Operator, market power mitigation, wholesale market design, transmission and distribution related issues, and retail competition.⁶⁷

⁶⁴ Ibid: 23-25.

⁶⁵ The MDC also: issued four quarterly reports; issued wholesale market rules; provided advice to the OEB on issues associated with the design of a retail market; issued standalone Technical Reports; delivered to the government a proposed agreement with Ontario Power Generation on market power mitigation; and delivered to the government a proposed governance and structure by-law for the Independent Market Operator.

⁶⁶ Market Design Committee, 1999: 1-2.

⁶⁷ Ibid: 4-14.

4.5 Energy Competition Act, the Transition Period and the Market Power Mitigation Agreement

After the release of the MacDonald Committee Report and the Government's White Paper, the government passed Bill 35 - the *Energy Competition Act* in 1998. The *Energy Competition Act* launched the restructuring of Ontario's electricity sector by enacting the *Electricity Act, 1998* and revising the *Ontario Energy Board Act, 1998*. The government relied on the recommendations made by the MDC in its early reports when drafting the *Energy Competition Act, 1998*.

The *Ontario Energy Board Act* expanded the OEB's mandate to include the regulation of the monopoly functions of the electricity sector (transmission and distribution). As such, the OEB was granted the necessary powers to set the rates for the transmission and distribution companies operating in the province.

The main purpose of the *Electricity Act, 1998* was to facilitate competition in the generation and sale of electricity and to facilitate a smooth transition to competition. It also intended to:

- protect the interests of consumers with respect to prices and the reliability and quality of electricity service;
- promote economic efficiency in the generation, transmission and distribution of electricity; and
- ensure that Ontario Hydro's debt is repaid in a prudent manner and that the burden of debt repayment is fairly distributed.⁶⁸

The *Energy Competition Act* essentially unbundled Ontario Hydro into five successor companies:

- (1) Ontario Power Generation ("OPG") was created to own and operate Ontario Hydro's existing generation assets;

⁶⁸ *Energy Competition Act, 1998*: Section 1.

(2) Ontario Hydro Services Corporation (later renamed Hydro One Networks) was created to own and operate the transmission and retail distribution assets formerly owned by Ontario Hydro;

(3) the Ontario Electricity Financial Corporation was created to assume and manage the stranded debt of Ontario Hydro;⁶⁹

(4) the Electrical Safety Authority was established to assume Ontario Hydro's safety inspection functions; and

(5) the Independent Market Operator was established to oversee the wholesale market and the dispatch function necessary for the functioning of Ontario's electricity system.⁷⁰

During the transition period, between the time that the *Energy Competition Act* was passed and market opening in 2002, the electricity sector operated similarly to how it operated under Ontario Hydro from the consumers' perspective. Electricity consumers were still charged on a bundled basis (generation, transmission, distribution and other charges) for electricity service. The difference was, after the restructuring, the successor companies of Ontario Hydro operated their businesses separately. OPG received the bundled payments and streamed the funds to the relevant service providers. The charges applied to consumers during this transition period were designed to provide OPG with planned revenues of 4 cents / kWh (based on a forecast of energy demand) and maintain OPG's revenue (on a per kWh basis) at the same level over the transition period.⁷¹

Prior to market opening, OPG and the provincial government signed the Market Power Mitigation Agreement. The purpose of the agreement was to ensure that OPG did not use its substantial market power to influence the wholesale market for electricity. As a result of the Market Power Mitigation Agreement OPG sold off some of its generation

⁶⁹ Treblicock and Hrab, 2006: 423-424, 434.

⁷⁰ Winfield, 2012: 103, 134.

⁷¹ Ontario Power Generation, 2001: 23-24.

assets (including some of its nuclear portfolio and some of its price-setting hydroelectric assets). The agreement also effectively established a partial price freeze on the amount that OPG could charge for its generated electricity after market opening.⁷² The “price cap” remained in effect from 2002 to April 2005.⁷³

MEUs could be viewed as departments within municipalities. In the same way that the municipality would provide water and garbage services, it would also provide electricity service to its residents. The *Electricity Act, 1998* required all municipalities to transform their electric utilities into for-profit companies under the *Business Corporations Act, 1990*. This meant that the MEUs became eligible to earn rates of return on capital (as set by the OEB). The *Electricity Act, 1998* also required the newly corporatized distribution companies to make payments in lieu of taxes to the government.⁷⁴ At this time, the MEUs became known as Local Distribution Companies (“LDCs”) to reflect their new corporate structure.

It was understood by government that the introduction of competition would mean that Ontario Hydro’s successor companies would no longer have the assurance that they can recover all costs, and previously incurred debt, through competitive electricity rates. In April 1999, the Ministry of Finance determined that Ontario Hydro’s stranded debt was approximately \$20.9 billion (i.e. debt that the successor companies could not service in a competitive market). The *Electricity Act, 1998* provided for revenue streams to service the existing debt with the goal of ultimately retiring Ontario Hydro’s debt.

The government determined that Ontario Hydro’s stranded debt would be repaid through the following mechanisms. The electricity companies (OPG, Hydro One Networks, and the LDCs) would make payments in lieu of taxes to the government which would be streamed to the Ontario Electricity Financial Corporation.⁷⁵ The

⁷² Under the Market Power Mitigation Agreement, OPG was required to pay a rebate to consumers on 90% of its domestic output when the wholesale market price exceeded 3.8 cent / kWh.

⁷³ Ontario Energy Board, 2008a: 2, and Treblicock and Hrab, 2006: 424.

⁷⁴ Electricity Distributors Association, 2006: 22.

⁷⁵ Payments in lieu of taxes are equivalent to the corporate income, property, and capital taxes paid by private corporations.

cumulative annual combined profits of OPG and Hydro One Networks in excess of the government's \$520-million annual interest cost of its investments in the companies would go toward repaying stranded debt.

The estimated present value of the above revenues streams was \$13.1 billion. Therefore, the estimated balance remaining on the \$20.9-billion stranded debt was \$7.8 billion. This amount was called the "residual stranded debt." The *Electricity Act, 1998* established the Debt Retirement Charge, which was to be paid by electricity consumers until the residual stranded debt was eliminated.⁷⁶

Although the details had not been established in the 1998-1999 period when the *Energy Competition Act* was enacted, it eventually resulted in the establishment of a competitive market for electricity in Ontario. In the wholesale electricity market, electricity spot prices were set by the Independent Market Operator every five minutes in response to changing supply / demand dynamics. Consumers choosing to participate in the wholesale market paid the associated spot prices for electricity. Consumers who did not wish to participate in the wholesale market now had the option of signing a contract with an electricity retailer. It is important to note that the electricity market resulting from the *Energy Competition Act* did not have an automatic fixed-price option. If a consumer did not engage with a retailer, the consumer would purchase their electricity through their LDC and the LDC would charge the consumer the wholesale price for electricity. Therefore, default electricity supply was priced based on the spot prices arising from the competitive electricity market.⁷⁷

4.6 Privatization of Publically-Owned Companies

A fundamental goal of the Harris government regarding the restructuring was the sale of Ontario Hydro's legacy assets to private investors. The Market Power Mitigation Act speaks directly to this goal. By limiting the share of electricity generation capacity held

⁷⁶ Auditor General of Ontario, 2011: 122-126.

⁷⁷ Treblicock and Hrab, 2006: 425.

by OPG, the government was signaling its intent to sell off OPG's generation assets to the private sector.

The government did manage to sell and lease some of OPG's generation assets to the private sector. In May 2001, OPG leased its Bruce nuclear generation stations to British Energy (who partnered with some Canadian companies and union groups).⁷⁸ The Bruce nuclear stations had a combined generation capacity of 3,140MW and the lease was valued at \$3.2 billion.⁷⁹ In March 2002, OPG sold 4 hydroelectric generation stations on the Mississagi River with combined generation capacity of 490MW to Brascan Corporation for \$340 million.⁸⁰ These two ownership transfers reflect all of the generation assets that the government sold and leased to the private sector over the restructuring period.

In December 2001, the government announced its intention to sell Hydro One (which held Ontario Hydro's transmission and distribution assets). There were numerous opponents to the sale of Hydro One including: union's representing public employees, environmental advocacy groups (most notably the Ontario Electricity Coalition), the NDP party and some municipal governments. The Ontario Superior Court in 2002 made a decision, in response to a challenge brought forward by the Ontario Electricity Coalition, which stated that the legislature had not provided the government with the authority to sell Hydro One. This effectively blocked the sale of the provincially-owned transmission / distribution company to the private sector.⁸¹

As noted previously, the *Electricity Act, 1998* required all municipalities to transform their electric utilities into for-profit companies under the *Business Corporations Act, 1990*. This was a prelude to privatization. After the MEUs were transformed into corporations (now called LDCs), they became eligible to be sold by the municipality to

⁷⁸ British Energy would later file for bankruptcy and the lease was transferred to a group of Canadian companies.

⁷⁹ LExpert, 2001.

⁸⁰ Brookfield Energy, 2002a.

⁸¹ Winfield, 2012: 135-136.

private interests.⁸² Very few Ontario municipalities elected to sell their distribution businesses to private interests.^{83 84}

Overall, the government was not very successful at privatizing publically-owned assets in Ontario's electricity supply industry. Due to the Market Power Mitigation Agreement, OPG did sell off a modest portion of its generating assets to private interests. Hydro One continues to be owned by the provincial government and the vast majority of LDCs in the province are owned by municipal governments.

4.7 Competitive Market Opening and Electricity Pricing, Conservation and Supply Act

After a number of delays, Ontario's competitive electricity market finally opened on May 1, 2002. To facilitate the operation of the competitive market, whereby consumers could purchase the electricity commodity separately from the transmission and distribution services, electricity rates were unbundled. This means that consumers would now have separate line items on their bills reflecting the prices for the electricity commodity, transmission service and distribution service.

At market opening, retailers also entered the market and began offering fixed-price contracts to electricity consumers who did not wish to participate in the wholesale market for electricity.⁸⁵

The competitive electricity market opening in May 2002 coincided with hottest summer in 50 years, which resulted in electricity demand hitting record highs. The demand increase corresponded with a lack of supply (caused by nuclear plant refurbishment and

⁸² Ibid: 135.

⁸³ FortisOntario Inc., 2014.

⁸⁴ Currently, FortisOntario Inc. is the only investor-owned distribution utility in the province. It owns and operates distribution systems in Algoma District, Fort Erie and Port Colbourne.

⁸⁵ Treblicock and Hrab (2006: 425) estimated that, after market opening, approximately 1 million customers, or 23% of the total number of electricity consumers in Ontario entered into fixed price contracts with retailers.

unanticipated issues with coal-fired plants). Increased electricity demand, combined with a lack of generating capacity and a newly-operating competitive market led to substantial increases in the price of electricity. The weighted average of the wholesale electricity price during the first year of the competitive market was 6.2 cents / kWh.⁸⁶ Energy consumers began to communicate their extreme dissatisfaction with the restructuring and resulting rate shock.⁸⁷ The political repercussions of the price increase were quite severe.

In response to the rate shock and the subsequent criticism targeted at the electricity market by consumers, the provincial government decided to freeze retail electricity rates. In December 2002, the government enacted the *Electricity Pricing, Conservation and Supply Act, 2002*. The legislation froze retail electricity rates at 4.3 cents / kWh for small volume customers (e.g. residential, small commercial) and other designated customers. The legislation also offered refunds, retroactive to market opening (May 2002), to compensate for electricity rates paid by consumers that were in excess of the 4.3 cents / kWh cap. In addition, the government froze all transmission and distribution rates at their existing levels until May 1, 2006.⁸⁸ The retail price freeze resulting from the *Electricity Pricing, Conservation and Supply Act* was later expanded to include larger volume consumers (those consuming less than 250,000 kWhs / year, such as large commercial and small industrial customers). The provincial government was responsible for paying the difference between the market price and the frozen retail price to suppliers.⁸⁹

⁸⁶ The Independent Market Operator analyzed the wholesale market to determine whether it was truly the dynamics of supply and demand that caused the high wholesale price for electricity. It determined that no market manipulation by generators occurred during the 2002 summer. The Independent Market Operator also noted that the wholesale electricity market prices in Ontario, while high, were similar to those experienced in neighbouring jurisdictions during the summer of 2002.

⁸⁷ Swift and Stewart, 2004: 176, and Treblicock and Hrab, 2006: 425-431.

⁸⁸ Ontario Energy Board, 2012b.

⁸⁹ Treblicock and Hrab, 2006: 426.

4.8 2003 Provincial Election: Electricity Sector Impacts

During the 2003 provincial election campaign, all three main political parties made promises that they would maintain government ownership of electricity assets. McGuinty's Liberal party was eventually elected. During the campaign, the Liberal's promised to maintain the existing 4.3 cent / kWh price freeze until 2006, retire all coal-fired generation by 2007 and begin installing smart meters for all customers in the province.⁹⁰

The Liberal government inherited the responsibility of dealing with the reality that the price freeze resulting from the *Electricity Pricing, Conservation and Supply Act, 2002* was a significant burden on the province's finances. The revenue arising from the frozen retail price was not sufficient to cover the actual cost of electricity generation. This difference was being covered by taxpayers.⁹¹ As such, the government abandoned the retail price freeze previously established and, in 2003, introduced the *Ontario Energy Board Amendment Act (Electricity Pricing), 2003*. This established an interim electricity pricing structure, replacing the existing price cap beginning April 1, 2004, until a more permanent solution could be developed. Under the interim pricing structure, residential, low-volume and other designated consumers paid 4.7 cents / kWh for the first 750 kWh consumed per month and 5.5 cents / kWh for consumption above that level. The government tasked the Ontario Energy Board with creating a new pricing mechanism. In order to maintain the financial viability of the distribution companies, the *Ontario Energy Board Amendment Act (Electricity Pricing), 2003* also required the OEB to allow the LDCs to recoup certain costs, which under the *Electricity Pricing, Conservation and Supply Act, 2002* had been put on hold.⁹²

At the same time, the government established what is known as the "Electricity Conservation and Supply Task Force" (or the "Task Force"). In its final report, the Task

⁹⁰ Ibid: 435

⁹¹ Ibid.

⁹² Ontario Energy Board, 2012b.

Force concluded that Ontario was facing an impending shortfall of electricity supply (as a number of generation plants were nearing the end of their expected operational lives) and that the competitive market structure designed for the electricity through the *Energy Competition Act* would not result in sufficient investment to meet the province's supply requirements in the future. As such, the Task Force recommended abandoning the existing competitive market structure.

As an alternative, the Task Force recommended that the Independent Market Operator develop an integrated system plan, which would provide direction with regard to the development of the supply and demand assets needed to meet the provincial electricity requirements. The Task Force also recommended the establishment of a government agency that would be responsible for developing a conservation culture in Ontario.⁹³

4.9 Electricity Restructuring Act

In response to the Task Force's report, the government enacted the *Electricity Restructuring Act, 2004*⁹⁴ which was said to have "instituted the hybrid model for Ontario's electricity sector".⁹⁵ The hybrid system has distinctly competitive characteristics and also clearly regulated qualities.

The competitive aspect of the model is the continued operation of a pool market system, operated by the Independent Market Operator, which, under the *Electricity Restructuring Act* was renamed the Independent Electricity System Operator ("IESO"). The prices for wholesale electricity are based on frequent auctions between generators who wish to supply electricity into the pool.⁹⁶

The regulated aspect is the Regulated Price Plan ("RPP"), which set two separate prices for electricity. Under the RPP, one price is set for customers who use less than a

⁹³ Winfield, 2012: 164.

⁹⁴ Ibid: 165.

⁹⁵ Electricity Market Investment Group, 2006: 2.

⁹⁶ Treblicock and Hrab, 2006: 436.

prescribed monthly quantity of electricity and another price is set for customers who use more than the prescribed monthly amount of electricity. The prescribed monthly quantities depend upon the season.⁹⁷

The RPP price, set by the Ontario Energy Board, is adjusted twice each year (May 1 and November 1). The RPP is intended to provide stable prices in the short-run that reflect the actual cost of electricity generation over the long-run. The difference between the actual costs of electricity generation and the revenues generated through the RPP are captured in a variance account, which is trued-up when the RPP price is reset in the next period. This ensures that, over the long-term, customers that pay the RPP price are paying the actual cost for the electricity commodity. The OEB sets the RPP rate on an estimate of how much it will cost to supply electricity to consumers over the next year.⁹⁸

The *Electricity Restructuring Act* also created the Ontario Power Authority (“OPA”). The OPA was tasked with developing a 20-year integrated power system plan (“IPSP”) for the electricity system and entering into contracts for the procurement of supply and conservation services.⁹⁹ Effectively, the OPA was established to take responsibility over the system planning function previously held by the IESO. The OEB is tasked with reviewing the IPSP to ensure that it complies with any directives issued by the Ministry of Energy and is economically prudent and costs effective.¹⁰⁰

While the *Electricity Restructuring Act* was said to have implemented a “hybrid model” for Ontario’s electricity sector¹⁰¹, which includes both competitive and regulated aspects, the competitive aspect of the “hybrid model” has been significantly diluted by government policies. It is true that after the *Electricity Restructuring Act* a pool market

⁹⁷ Ibid: 437.

⁹⁸ Ontario Energy Board, 2014b.

⁹⁹ Winfield, 2012: 164.

¹⁰⁰ Ontario Energy Board, 2012b.

¹⁰¹ Electricity Market Investment Group, 2006: 2.

system for electricity continued to exist in Ontario (where generators bid to supply electricity to the market). However, the OPA was mandated to procure electricity generation (and conservation services) for the province under long-term fixed-price contracts. In addition, the OEB was mandated to regulate the price paid to OPG for electricity generated from its “prescribed assets” (i.e. nuclear and baseload hydroelectric generation assets). As I will discuss, in detail, later in this paper, nearly all of Ontario’s generators are paid at a regulated or fixed price (under contract). This means that there is very little generation in the province that is entirely paid for at the wholesale market price. To address this disconnect between the wholesale price for electricity and the actual price paid to generators for their output, the global adjustment was created.

The global adjustment is designed to capture the difference between the revenues generated through the wholesale market price and the actual amount paid to contracted and / or regulated generators for their output. The global adjustment is calculated based on the difference between the Hourly Ontario Electricity Price and the regulated rates paid to OPG for its prescribed assets, the contracted rates paid by the OPA to its contracted generation stations (new gas-fired facilities, renewable generators, and new nuclear capacity), and the contracted rates paid by the Ontario Electricity Financial Corporation to the NUGs that were previously under contract with Ontario Hydro. The global adjustment ensures that the revenues collected from ratepayers for the electricity commodity cover the actual cost of generation.^{102 103}

The government’s generation procurement framework (as managed by the OPA), and the payment of regulated prices for OPG’s prescribed assets, has nearly eliminated the competitive aspect that remained in the “hybrid model” as was established through the *Electricity Restructuring Act, 2004*.

¹⁰² The global adjustment is also designed to recover costs associated with delivering conservation programs in the province.

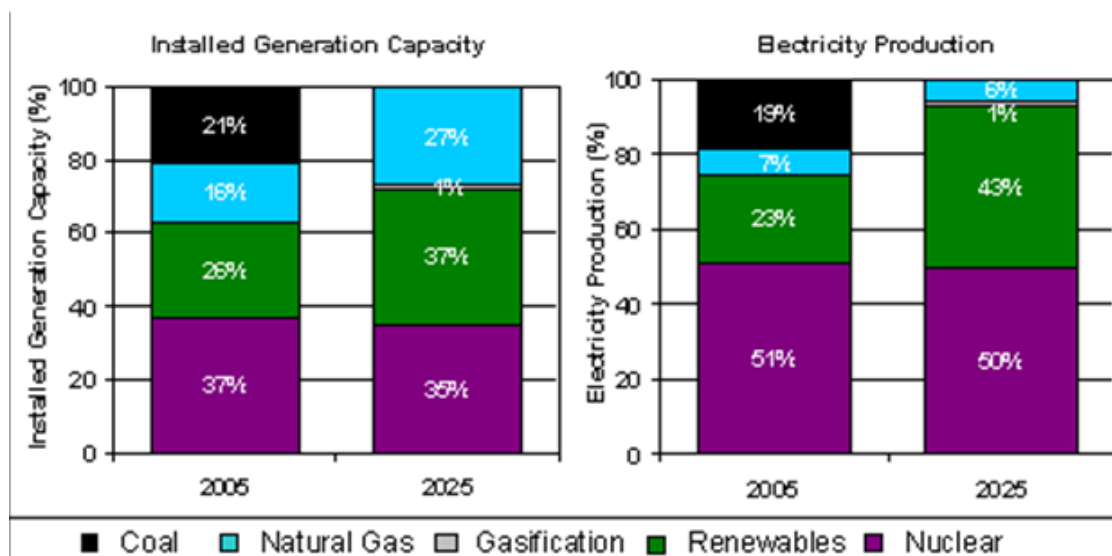
¹⁰³ Independent Electricity System Operator, 2014a.

4.10 The Role of the OPA, the IPSP, and the Green Energy and Green Economy Act

The OPA was established to take responsibility over the system planning function for Ontario's electricity sector. It was mandated to ensure an adequate, reliable and secure supply of electricity in Ontario. As such, the government directed the OPA to develop a 20-year plan called the "Integrated Power System Plan".

In December 2005, the OPA released its advice regarding Ontario's electricity supply mix that would allow the province to meet its energy demands for the period 2005 - 2025. The supply mix advice provided in 2005, which was a precursor to the first IPSP filed with the OEB in 2007, is summarized in the following chart.

Figure 2 - OPA 2005 Supply Mix Advice¹⁰⁴



In June 2006, the Minister of Energy issued a directive to the OPA ("June 2006 Minister Directive") that, among other matters, set out its expectations regarding the IPSP (i.e. peak demand reduction through conservation activities, reliance on renewables, limits on nuclear capacity, and use of gas-fired generation). It also set out the government's direction with regard to the planned phase out of coal generation. On the coal

¹⁰⁴ Ontario Power Authority, 2005.

generation issue, the government stated: “Plan for coal-fired generation in Ontario to be replaced by cleaner sources in the earliest practical timeframe that ensures adequate generating capacity and electricity system reliability in Ontario.”¹⁰⁵

On the basis of the June 2006 Minister Directive, the OPA went about developing the 20-year IPSP. On August 29, 2007, the OPA filed the IPSP with the OEB which was responsible for reviewing the plan with regard to cost effectiveness and prudence. Shortly after receiving the application, the OEB established a plan for the hearing process (including procedural steps for serving notice, discovery, etc.).

The OEB had already gone through several procedural steps and dealt with some Motions on the application from interested parties when, on September 17, 2008, the Minister of Energy issued another directive to the OPA requiring it to make certain revisions to the IPSP that had been submitted for regulatory approval.¹⁰⁶ The Minister asked the OPA to reconsider the amount and diversity of renewable energy in the supply mix, possible conversions of coal plants to biomass, specific improvements to transmission planning, amongst a number of other items. As a result, on October 2, 2008, the OEB decided that it would put its proceeding on hold until the revised plan was filed.¹⁰⁷

In the fall of 2008, the global financial crisis caused massive problems for individuals, corporations and governments all across the world. It caused great harm to the North American auto manufacturing industry which was central to Ontario’s manufacturing sector. Ontario’s economy lost nearly 250,000 jobs between the fall of 2008 and the spring of 2009. McGuinty’s Liberal government made an effort to link the province’s economic recovery to environmental sustainability. It did so largely through the passing of the *Green Energy and Green Economy Act, 2009* (“*Green Energy Act*”).¹⁰⁸ The *Green Energy Act* largely focused on promoting renewable generation (through the

¹⁰⁵ Dwight Duncan, 2006: 2.

¹⁰⁶ Ontario Power Authority, 2008.

¹⁰⁷ Ontario Energy Board, 2009a: 2.

¹⁰⁸ Winfield, 2012: 179-180.

creation of a generous feed-in tariff program), promoting conservation and demand-side management, and the implementation of a smart grid in Ontario.^{109 110} The *Green Energy Act* also required the OPA to revise the IPSP to reflect the inclusion of a greater reliance on renewable generation sources.¹¹¹

In November 2010, the government of Ontario released its Long-Term Energy Plan titled, “Building Our Clean Future Together”. A few months later, the government issued an updated Supply Mix Directive to the OPA. The combined direction of the Long-Term Energy Plan and the 2011 Supply Mix Directive set out the goals that the government expected the OPA to meet in a new updated IPSP. The government, in 2011, directed the OPA to develop and submit a new IPSP (which the OPA termed IPSP II) with the OEB.¹¹² As of 2014, no updated IPSP has ever been filed. However, the Long-Term Energy Plan does provide the forecasted electricity needs of the province until 2030 and sets out what the government believes is the most effective way to meet those requirements.¹¹³ It also provides information and policy direction that is similar to what would be expected to be found in an updated IPSP. However, it is important to note that a significant difference between the government’s Long-Term Energy Plan and the OPA’s IPSP is that there was no prudence, or cost-effectiveness, review of the Long-Term Energy Plan which would have occurred if an updated IPSP was filed with the OEB.

4.11 Energy Consumer Protection Act

The *Energy Consumer Protection Act* received Royal Assent on May 18, 2010 and came into force on January 1, 2011. It effectively required the OEB to establish a new

¹⁰⁹ Note that Smart Meter installation actually began before the introduction of the GEA. But the GEA formalized the government’s plan for a “smart grid” in Ontario.

¹¹⁰ Ontario Ministry of Energy, 2013a.

¹¹¹ Winfield, 2012: 181.

¹¹² Ontario Power Authority, 2011.

¹¹³ Ontario Power Authority, 2010.

framework for the regulation of licensed electricity retailers and natural gas marketers. This legislation was enacted by the government in response to concerns regarding the business practices of retailers operating in the electricity and natural gas markets in Ontario.

The *Energy Consumer Protection Act* caused the OEB to issue revised Retailer Codes of Conduct; required retailers to release contract verification / renewal / extension call scripts; provide mandatory disclosure statements; and launch price comparison templates that must be used by electricity and natural gas retailers when offering their products to consumers.¹¹⁴

Overall, this legislation significantly tightened the rules and regulations surrounding the provision of retail electricity and natural gas services in the province.

4.12 Changes to Ontario's Tax System

In July 2010, the Goods and Services Tax and Provincial Sales Tax was replaced by the Harmonized Sales Tax ("HST"). Prior to the transition to the HST, electricity consumers were paying an effective tax of approximately 7% on their electricity bills. After the transition, the 13% HST was applied to electricity bills.¹¹⁵ The change to tax system resulted in higher taxes being paid for electricity services.

4.13 Ontario Clean Energy Benefit Act

The Ontario Clean Energy Benefit came into force on January 1, 2011. It provides financial assistance to small volume electricity consumers (i.e. residential and small commercial). Specifically, the Ontario Clean Energy Benefit provides a 10% rebate off the total electricity bill (including commodity, distribution, regulatory, debt retirement and HST) for the first 3,000 kWhs of monthly consumption.¹¹⁶ The rebate is paid for by the

¹¹⁴ Ontario Energy Board, 2014a.

¹¹⁵ Treasury Board of Canada, 2010.

¹¹⁶ Ontario Ministry of Energy, 2013b.

province using general tax revenue. This discount was implemented by the Liberal government in order to mitigate rising energy costs that were being attributed to the *Green Energy Act* in an attempt to please voters prior to the provincial election.

4.14 Distributor Mergers

Prior to the electricity sector restructuring there were over 300 MEUs operating in the province. As noted previously, the Government's White Paper recommended that efficiencies could be gained through the amalgamation of these distribution companies (now known as LDCs). It is important to note that throughout the post-restructuring period, the amalgamation of distributors has been a voluntary activity.¹¹⁷ Over the years, a number of distributor amalgamations have occurred. Currently, there are 77 LDCs operating in Ontario.¹¹⁸

For the most part, the amalgamations that occurred in Ontario did not happen due to provincial government policy or legislation. It was, in fact, municipal policy that led to the largest number of distributor mergers. As municipalities amalgamated so did their respective distribution companies. Hydro One also drove a large number of mergers by acquiring a number of distribution companies that Ontario Hydro operated under contract. Essentially, these were distributors that were owned by a municipality but had always been operated by Ontario Hydro. After the restructuring, Hydro One purchased these small local distributors and folded them into their overall distribution business.

These two reasons (i.e. municipal amalgamations and Hydro One acquiring distribution companies that Ontario Hydro previously operated under contract) reduced the number of distributors operating in Ontario from over 300 to about 120. The remainder of the mergers, which reduced the total number of distributors in the province from 120 to 77,

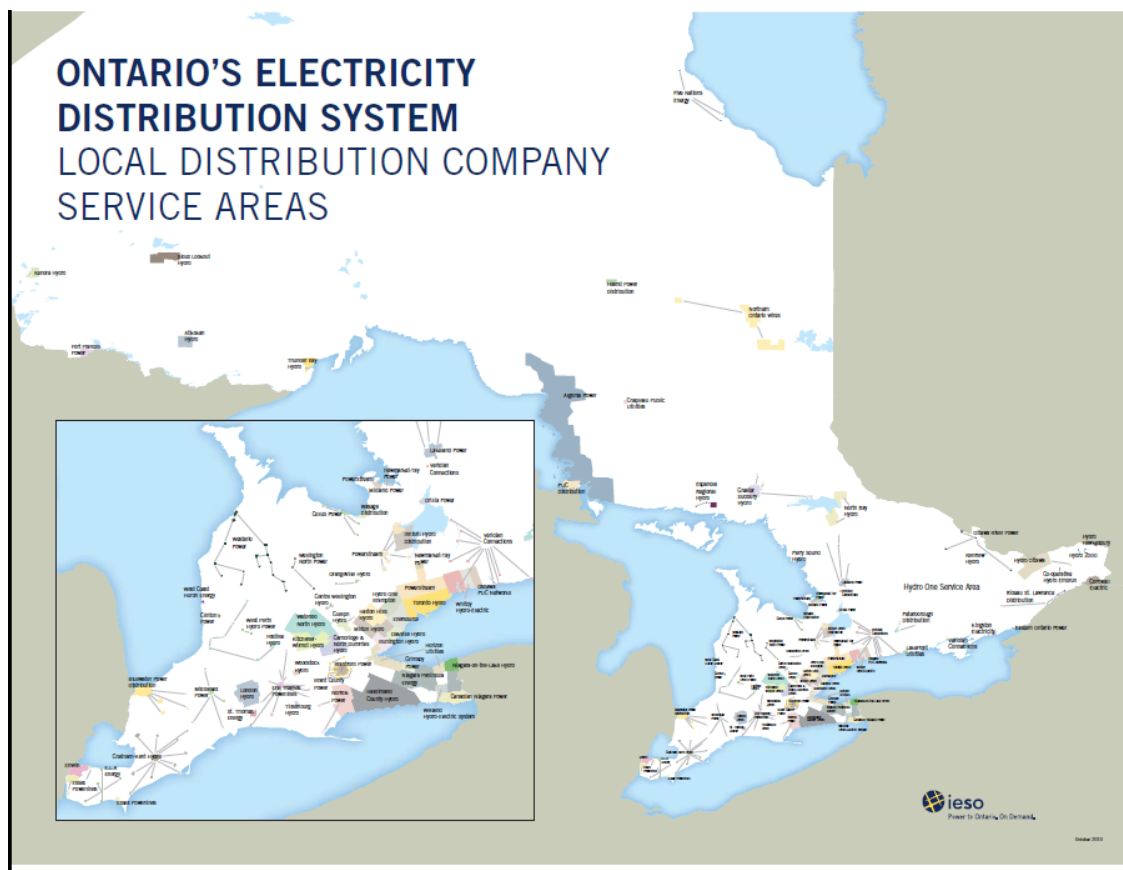
¹¹⁷ C.D. Howe Institute, 2013a: 6.

¹¹⁸ Ontario Energy Board, 2012b.

largely occurred due to managerial decisions made by the LDCs during the mid to late 2000s.^{119 120}

The following map shows the location of all of the LDCs in the province as of 2010.

Figure 3 - LDC Service Area Map¹²¹



4.15 Smart Grid Implementation

Over the post-restructuring period, the electricity distributors and the IESO (which operates the Smart Metering Entity) have worked towards the implementation of a smart grid in Ontario. As noted previously, the government's formal plan for a smart grid in

¹¹⁹ C.D. Howe Institute, 2013a: 5-6.

¹²⁰ It is important to note that the distributor mergers and acquisitions that occurred in Ontario were almost entirely between municipalities. Very few distribution businesses were purchased by private interests.

¹²¹ Independent Electricity System Operator, 2010a.

Ontario was set out in the *Green Energy Act*. However, the installation of smart meters actually began prior to the enactment of the *Green Energy Act*.

The primary purposes of developing a smart grid are to facilitate the implementation of time-of-use (“ToU”) pricing (by deploying smart meters) and facilitate the connection of distributed generation (the intermittent nature of distributed generation necessitates greater operational control of the distribution network which is achieved by using ‘smart grid’ technologies).

ToU pricing applies the lowest price for electricity consumed in periods of the lowest demand and the highest price for electricity consumed in periods of the highest demand.¹²² The purpose of ToU pricing is to shift consumption from periods of peak demand to periods that experience lower demand levels. The benefits of reducing peak demand are avoidance of building additional capacity (either generation, transmission, or distribution) and the reduction of greenhouse gas emissions (since generation supplies used to meet peak demand tend to be less environmentally-friendly in Ontario). In addition, ToU prices better reflect the actual cost of electricity generation as generators used to meet peak demand tend to also be more costly sources of electricity.

ToU implementation occurred relatively quickly. In August 2010, nearly 92% of all eligible customers¹²³ had smart meters installed and approximately 20% of eligible customers were subject to ToU pricing.¹²⁴ Two years later, by August 2012, nearly 100% of eligible customers in Ontario had smart meters installed and approximately 91% of eligible customers were subject to ToU pricing.¹²⁵

¹²² Ontario Energy Board, 2014e.

¹²³ Eligible customers refer to those customers that are eligible for regulated price plan pricing. This includes all small volume customers (<250,000kWh of annual consumption) and certain other designated customers.

¹²⁴ Ontario Energy Board, 2010a: 3.

¹²⁵ Ontario Energy Board, 2012c: 4.

4.16 Ontario's Electricity Sector: Today

Ontario's electricity sector continues to follow the framework established by the *Electricity Restructuring Act, 2004*. The pool market system continues to operate and the OEB still sets the RPP price for small volume customers. The OEB also continues to regulate the prices for transmission and distribution services in Ontario.

With regard to pricing for the electricity commodity, small volume customers, which include all residential and small commercial customers, have the option of paying the RPP based price for electricity or to sign a contract with an electricity retailer. ToU prices are applied to almost all RPP customers. Large volume customers (with consumption greater than 250,000 kWhs a year) can either pay the wholesale market price for electricity or sign a contract with an electricity retailer. If a customer elects to pay the market price, depending on their metering situation, the customer will either pay the Hourly Ontario Electricity Price or a weighted wholesale price (which is based on the consumption pattern of their local distributor).¹²⁶

It is important to note that all large and small volume customers on a retail contract pay the global adjustment directly (as a separate line item on their respective bills); the global adjustment is not included in the commodity price offered by retailers.

Conversely, small volume customers subject to the RPP pay the global adjustment indirectly since the RPP price is set at level that is designed to recover the total cost of generation; in other words, the global adjustment is included in the RPP price.¹²⁷

These are the primary companies and organizations involved in Ontario's electricity industry today:

- OPG continues to be the dominant generator in the province. In 2012, nearly 60% of Ontario's generated output was sourced from OPG.¹²⁸

¹²⁶ Independent Electricity System Operator, 2014b.

¹²⁷ Ontario Energy Board, 2014e.

¹²⁸ Independent Electricity Operator, 2014c.

- Hydro One is the main transmitter in the province. Currently, Hydro One owns and operates almost 30,000 km of high-voltage transmission lines in the province. This represents nearly 97% of Ontario's transmission assets.¹²⁹
- There are 77 LDCs operating distribution systems in the province. This is a large decrease in the number of distributors when compared to the number operating in the province prior to restructuring.
- The IESO continues to be the system operator, managing the system on a minute-to-minute basis in order to balance supply and demand.
- The OPA continues to be the system planner. The OPA is responsible for developing long term plans for the electricity sector and is also responsible for signing and managing long-term contracts with generators.
- The OEB is the regulator for the sector. It sets the RPP price for the electricity commodity, sets transmission and distribution rates, licences market participants, adjudicates leave to construct applications (for the development of transmission and distribution capital projects), and also has a policy development function.
- The Ontario Electricity Financial Corporation continues to manage the debts of the former Ontario Hydro. It also manages the contracts with the NUGs that were previously managed by Ontario Hydro.

The supply mix in Ontario has changed over the years. Renewable generation is beginning to play a greater role. The OPA, under various programs designed to incentivize the installation of renewable capacity, has been signing long-term contracts for renewable generation. Some of these renewable generators are already online and more will be coming online in the future. For 2012, Ontario's generation output by source is set out in Figure 4. A full discussion of the shift in Ontario's supply mix will be provided later in this paper.

¹²⁹ Hydro One Networks, 2013.

Figure 4 - Ontario Generation Output by Source (2012)¹³⁰

Over the restructuring period, projects have been underway to modernize the grid. Smart meters have been installed all across the province and the Smart Metering Entity has been established which allowed for the implementation of ToU billing structures. Other grid modernizing investments have been made to enable connection of the renewable generation for which the OPA has been contracting.

In summary, the electricity sector continues to follow the framework established by the *Electricity Restructuring Act, 2004*. There has been progress made with regard to implementing renewable energy sources as part of Ontario's supply mix and modernizing the electricity grid.

4.17 Conclusion

Major changes have occurred in Ontario's electricity sector over the years. The sector transitioned from a traditional monopoly model characterized by a state-owned vertically-integrated utility (Ontario Hydro) to what has been called a "hybrid model",

¹³⁰ Derived from Independent Electricity System Operator, 2013c.

which includes both regulated and competitive aspects. This transition occurred in two phases:

- (1) A fully competitive electricity market opened in May 2002 (based on the framework established by the *Energy Competition Act, 1998*). The competitive market, in its original form, only operated until December 2002. Due to the price shock experienced by consumers immediately after market opening, in December 2002, the government froze electricity rates in order to address the concerns of customers regarding increasingly expensive electricity bills.
- (2) After a change in government, the *Electricity Restructuring Act, 2004* introduced a “hybrid model” for Ontario’s electricity sector. This model is still in operation today.

A number of other changes occurred in Ontario’s electricity sector after the restructuring was complete. Most significant was the enactment of the *Green Energy Act* in 2008. This legislation set out an ambitious plan for promoting electricity conservation, implementing renewable generation as part of Ontario’s supply mix, and modernizing the grid.

The remainder of the paper will focus on the impact that the restructuring, and the post-restructuring policies of government, had on consumers. The impacts will be analyzed from both an economic and environmental perspective.

5. Methodology

5.1 Introduction

The purpose of this paper is to answer the research question: from an economic and environmental perspective, how have Ontario's electricity consumers been impacted by changes resulting from the restructuring and post-restructuring policies of government? In order to answer this question a number of related analyses are performed.

First, I provide a comprehensive analysis of both the "all-in" electricity prices (which is described, in detail, in sub-section 5.3.1) and distribution prices in the pre- and post-restructuring periods. In order to perform this analysis, I utilize two comparative analysis frameworks (1983-1997 vs. 1998-2012 and 1991-1997 vs. 2006-2012).

I then use statistical analysis techniques to determine whether the restructuring, and certain post-restructuring, policies of government are correlated to changes in electricity prices over time.

Once an understanding of the electricity prices (and their correlation to the policies of government) is established, I look at all of the major price drivers that impacted electricity prices over the post-restructuring period.

I then, individually, analyze each of the price drivers that caused electricity prices to increase over the post-restructuring period, through both an economic and environmental lens, to determine the impact that they had on consumers.

Overall, there are three core areas, related to Ontario's electricity sector, that I analyze for the purpose of this paper:

- (1) Electricity Prices & Cost Drivers;
- (2) Competition in Generation & Retail Supply; and
- (3) Supply Mix & Conservation.

This section provides an understanding of the underlying data which forms the foundation for each area of analysis in this paper. Specifically, this section includes a discussion of the rationale for the selected timeframe over which changes to Ontario's electricity prices are analyzed; the inflation adjustment methodology utilized and the rationale for selecting the methodology; the statistical methodology used to analyze the price data; and the limitations associated with the analysis undertaken in this paper.

5.2 Electricity Prices: Time-Series Analysis

There are many factors that impact the price of electricity, which makes it difficult to find two time periods (one before and one after the sector restructuring) which would provide for an equitable analysis of pricing.

The ideal manner in which an analysis and comparison of electricity prices over two periods of time would be undertaken involves maintaining a consistent sector design and framework. In the case of Ontario's electricity sector, this would require information for the post-restructuring period (1998-2012) which reflects hypothetical prices that would be charged to consumers had the sector never been restructured. However, given that this type of hypothetical information is not available and cannot, with any level of accuracy, be estimated, the analysis undertaken in this paper utilizes two comparative frameworks to analyze actual changes in electricity prices over time. Knowledge of internal and external changes (i.e. political decisions, economic factors, etc.) that have impacted Ontario's electricity sector was used to develop appropriate comparative frameworks under which the impacts of the restructuring and post-restructuring changes can be isolated and analyzed.

The two comparative analysis frameworks selected for analyzing the changes in electricity prices before and after restructuring are discussed below.

The first comparative analysis framework uses the period from 1983-1997 to reflect the pre-restructuring era and 1998-2012 to reflect the post-restructuring era. These timeframes reflect the 15 years before and after restructuring. Given the capital intensity

of the electricity sector, generally, longer timeframes for analysis are better as they offer a better reflection of the capital stock cycle.

This time period, however, includes 8 years where there is no actual electricity pricing data available (1998-2005). Prior to 1998, Ontario Hydro maintained the records for electricity pricing data. However, after the restructuring, Ontario Hydro stopped reporting electricity prices (as the employees were largely moving to the new organizations established by the restructuring). The responsibility for maintaining the pricing data records was passed onto the OEB but it did not begin reporting electricity prices until 2006. In the period immediately after the restructuring, a transition information team was established. However, membership of the transition information team was voluntary and the team had no power to compel the disclosure of information. The transition information team was focused on gathering data to assist market participants prepare for market opening and was not collecting the same electricity pricing information that was available under Ontario Hydro. In addition, the information provided by the transition team is only available from 1999 until the end of 2000.¹³¹ Therefore, the information collected and reported by the transition information team is not useful for the analysis that is undertaken in this paper. In short, there is no pricing data available for the period 1998-2005 leaving an 8 year gap in the electricity pricing data.

The lack of publically-available electricity pricing information for an 8 year period is a major concern as it makes policy analysis significantly more difficult. The government should have appointed a team responsible for gathering and reporting the same information that was reported by Ontario Hydro prior to the restructuring. This would have ensured that important pricing information was available after the electricity sector restructuring, which would have maintained public transparency and provided the government with the necessary information to allow it to evaluate whether its policy decisions were producing the intended outcomes. In the future, if the government were to undertake a further sector restructuring, provisions should be made to ensure reporting functions are maintained.

¹³¹ Transition Information Team, 2000: 3-7.

As such, in the comparative analysis that utilizes the period from 1983-1997 to reflect the pre-restructuring era and 1998-2012 to reflect the post-restructuring era, year-to-year volatility is ignored for the period 1998-2005.

Another issue with the 1983-2012 time series is that generation capacity increased significantly during the 1983-1998 period (the Bruce B and Darlington nuclear stations were put online) while during the 1998-2012 period installed capacity increased to a much lesser extent. From 1983 to 1998, dependable installed capacity increased from 21,600MW to 31,000MW.¹³² This reflects an increase of 9,400MW. In contrast, from 1998 to 2012, dependable installed capacity increased from 31,000MW to 35,000MW.¹³³ This reflects an increase of 4,000MW. Therefore, dependable installed capacity increased by 5,400MW more in the pre-restructuring period than the post-restructuring period in this comparative analysis framework.¹³⁴ This introduces some uncertainty regarding the results of an electricity pricing comparison between the pre- and post- restructuring periods when using the first comparative analysis framework.¹³⁵

¹³² Ontario Hydro Statistical Handbooks, 1983-1992 & Ontario Hydro Annual Reports, 1995, 1996, 1998.

¹³³ Independent Electricity System Operator, Monthly Generator Disclosure Reports, 2003-2008 & Independent Electricity System Operator, 2013b.

¹³⁴ In both time periods, plant retirements / long-term shutdowns occurred. In the pre-restructuring period, plants were taken offline largely because they were at the end of their useful lives (and were either retired completely or refurbished over extended periods of time). Ontario Hydro did not provide information about capacity retirements in the publically-available information that has been used for this paper. However, looking at the full list of generators provided in some annual editions of Ontario Hydro's Statistical Handbooks it is possible to estimate that approximately 2,000MW of capacity was either retired or taken offline for long-term repairs between the 1980s and the 1990s. In the post-restructuring period, a number of Ontario's coal plants were retired due to government policy. The IESO reports approximately 4,300MW of capacity retirements between 2003 and 2012. Therefore, more capacity retirements occurred in the post-restructuring period than in the pre-restructuring period. This narrows the difference, to some extent, in dependable capacity development between the pre- and post- restructuring periods. However, even with the retirements / long-term refurbishments taken into account, there was still more dependable capacity brought online during the 1983-1997 period than in the 1998-2013 period.

¹³⁵ This uncertainty arises as it is not known to what extent the cost of the incremental generation capital investment that occurred during pre-restructuring period was included in the electricity prices that prevailed during pre-restructuring period. It is likely that some portion of this investment was passed onto consumers in the pre-restructuring period as the costs came online. However, it is likely that some other portion of these capital investment costs accumulated as additional long-term debt held by Ontario Hydro. If some portion of the incremental pre-restructuring capital investment in generation capacity did accumulate as long-term debt, this would impact the electricity prices in the post-restructuring period as the debt costs of Ontario Hydro are being paid by electricity consumers in the post-restructuring period in

The second comparative analysis framework uses the period from 1991-1997 to reflect the pre-restructuring era and 2006-2012 to reflect the post-restructuring era. This reflects the 7 years before restructuring and a 7 year period after restructuring (where actual electricity pricing data is available). The benefit of this analysis period is that there is no gap in the dataset and concerns around capacity investment differences between time periods are mitigated (as the differential in dependable capacity additions is narrowed to 2,500 MW between the pre- and post- restructuring period).¹³⁶ However, a drawback of this analysis framework is that it has less pricing data points, which renders the results of the analysis less reliable.

In both comparative analysis frameworks, the pricing information reflects the price freezes that were in place over the 1993- April 2005 period. The pricing information is impacted by the following price restrictions: (a) the price freeze on Ontario Hydro's retail rates during the pre-restructuring period from 1993-1998; (b) the transition period pricing limitations placed on OPG's generated output from 1998-May 2002; (c) the partial freeze on the amounts that OPG was paid for its generated output during the 2002- April 2005 period under the Market Power Mitigation Agreement; and (d) the freeze on all components of the electricity price that was applied retroactively to May 2002 (market opening) and was in effect until 2004.

Each comparative analysis framework has inherent strengths and weakness as discussed above. It is not possible to find two periods of time (one before and one after the sector restructuring) that would provide for a perfectly equitable comparison as there are a great number of factors that impact the price of electricity. However, by utilizing

their electricity rates (and these costs are captured in the "all-in" electricity prices which is discuss later in this paper).

¹³⁶ Derived from Ontario Hydro Statistical Handbooks, 1990-1992, Ontario Hydro Annual Reports, 1995, 1996, 1998, Independent Electricity System Operator, Monthly Generator Disclosure Reports, 2003-2008, and Independent Electricity System Operator, 2013b.

two distinct comparative analysis frameworks to study electricity prices in Ontario a more comprehensive analysis can be provided.¹³⁷

It is important to note that 1998 is the year that the electricity sector restructuring actually began. Throughout the paper, when the post-restructuring period is mentioned, it is the post-1998 period that is being discussed.

5.3 Data Collected

5.3.1 “All-in” Electricity Price

I have developed a dataset which provides the total price of electricity for consumers in Ontario on a per kWh basis. This pricing dataset covers the periods 1983-1997 and 2006-2012. The “all-in” electricity pricing information can be found at section 8.2. As noted previously, there is no electricity pricing data available for the period 1998-2005. This pricing data reflects the total cost of providing electricity service including the commodity, distribution, transmission and regulatory costs.¹³⁸

This dataset effectively provides the average “all-in” price for electricity service for consumers in Ontario (in \$/kWh). In practice, electricity rates vary between rate classes. Rate classes are comprised of customers that have similar profiles and needs. For example, small volume residential customers pay different rates for electricity services than large volume industrial customers. These pricing differences reflect the underlying differences in the costs to serve customers that have different needs and consumption patterns.¹³⁹ However, for the purposes of the analysis completed in this paper, an average electricity price for all customers in the province is utilized.

¹³⁷ In regard to the statistical analysis of Ontario’s electricity prices, only the 1983-2012 time series has been used as the 1991-2012 data series has very few observations. This makes the results of the statistical analysis less meaningful as there is not sufficient data input for the regression.

¹³⁸ Note that taxes are not accounted for in the electricity pricing data presented in this paper.

¹³⁹ Costs are allocated to different rate classes on the basis of the principle of “cost causality.” Essentially, the principle of cost causality assigns (or allocates) the costs of providing electricity services to groups of customers (or rate classes) on the basis of which customers cause the costs to arise.

I developed the “all-in” price data using two different methodologies:

- a) Prior to restructuring (i.e. 1983-1997) a top-down approach was utilized. For the pricing information associated with the 1983-1997 period, Ontario Hydro’s primary revenues and the revenues of the MEUs were divided by total sale volumes to determine the average price (\$/kWh) for electricity service during the noted period.
- b) Post-restructuring (i.e. 2006-2012) a bottom-up approach was used. For the pricing information associated with the 2006-2012 period, the rates charged for all components of electricity service (with the exception of distribution service) were summed to develop an all-in electricity price. To derive distribution prices during the post-restructuring period, total distributor revenues were divided by total distributor sales volumes to determine the average price (\$/kWh) for distribution service.

The pricing information for the pre-restructuring period was sourced from Ontario Hydro’s Statistical Yearbooks and Ontario Hydro’s Annual Reports (1983-1999).¹⁴⁰ For the post-restructuring period, the pricing information was sourced from both the IESO¹⁴¹ and the OEB.¹⁴²

I calculated the pricing information for the period 1983-1992 and from 2006-2012 based on sales volumes that include transmission losses. However, during the 1993-1997 period, Ontario Hydro’s statistical yearbooks did not include sales volume information. As such, sales volume information was sourced from Ontario Hydro’s annual reports for that period. The sales volumes provided in the annual reports did not include transmission losses. Therefore, in order to ensure that the volumes are comparable on a like-for-like basis, the volumes reported by Ontario Hydro for the 1993-1997 period

¹⁴⁰ Ontario Hydro Statistical Handbooks, 1983-1997 & Ontario Hydro Annual Reports, 1990-1999.

¹⁴¹ Independent Electricity System Operator, 18-month Outlook Tables, May 2013 & February 2014, & Independent Electricity System Operator, Monthly Market Reports, 2006-2012.

¹⁴² Ontario Energy Board, Yearbook of Electricity Distributors, 2006-2012.

were grossed-up to include transmission losses. Essentially, the average transmission losses for the 11 years prior to 1993 were used as proxy for transmission losses for the 1993-1997 period. The average transmission losses for the period 1982-1992 was 4.29%. Therefore, the volumes associated with the 1993-1997 period were grossed up by 4.29% to reflect an estimate of transmission losses for those years. This was the only adjustment that I made to the actual data sourced from the above noted reports.

Overall, the information that I provided in this dataset is meant to be reflective of the total price paid for electricity service (on a \$/kWh) basis for all consumers in Ontario over the 1983-2012 period.

5.3.2 Distribution Price

This dataset provides the price for distribution services for Ontario electricity consumers on a per kWh basis. It also covers the periods 1983-1997 and 2006-2012. The distribution pricing information can be found at section 8.3. As noted previously, there is no electricity pricing data (including distribution pricing) available for the period 1998-2005.

Similar to the “all-in” pricing information, discussed above, the pricing information included in this dataset reflects an average price for all consumers in the province. As such, actual pricing differences by rate class have been ignored.

The pricing information related to the pre-restructuring period (1983-1997) and the post-restructuring period (2006-2012) were both developed using a top-down methodology. For all years, the total distribution revenues received by the distributors were divided by distribution volumes to derive an average distribution price (\$/kWh).

The distribution pricing information for the pre-restructuring period was sourced from Ontario Hydro’s Statistical Yearbooks.¹⁴³ For the post-restructuring period, the pricing

¹⁴³ Ontario Hydro Statistical Handbooks, 1983-1997.

information was sourced from the Ontario Energy Board's Yearbook of Electricity Distributors.¹⁴⁴

There is a slight difference in the distribution pricing information collected for the pre-restructuring period and the post-restructuring. In the pre-restructuring period, the distribution related information provided in Ontario Hydro's Statistical Yearbooks does not include Ontario Hydro's retail business.¹⁴⁵ Therefore, the average distribution price derived for that period does not include the distribution prices paid by retail customers of Ontario Hydro. In contrast, the average distribution price calculated for the post-restructuring period includes Hydro One's distribution business. Hydro One's distribution business largely includes those customers that, prior to the restructuring, were served directly by Ontario Hydro. The distribution pricing information for the post-restructuring period is more comprehensive than the information for the pre-restructuring period as it covers all the customers in the province (with the exception of a very small number of customers served by three non-rate regulated utilities). This difference in the underlying distribution pricing data for before and after the restructuring means the distribution pricing comparison is not perfectly equitable. It is important to note that this problem is not present in the "all-in" electricity pricing dataset as the derivation of the all-in price utilizes the total revenues of Ontario Hydro (including its retail related revenues).

5.3.3 "All-In" Electricity Price and Distribution Price - Inflation Adjustment

I provided the all-in electricity prices and the distribution prices on both a nominal and inflation-adjusted basis. In order to analyze pricing information over extended periods of time, an inflation adjustment is made in order to isolate any changes on the prices being studied net of the impact that inflation has on the underlying costs.

Both a CPI based inflation-adjustment and a gross domestic product implicit price index final domestic demand ("GDP IPI") based inflation-adjustment were considered. I

¹⁴⁴ Ontario Energy Board, Yearbook of Electricity Distributors, 2006-2012.

¹⁴⁵ The revenues received by Ontario Hydro related to its distribution business were included as part of its total revenues in its annual reports. However, there is no way to breakout the revenues received by the company as between commodity, transmission and distribution.

decided that the GDP IPI adjustment is preferable to a CPI-based adjustment. GDP IPI tracks a set of goods and services that are more relevant to the electricity sector. As noted by the OEB, which uses GDP-IPI as the inflation proxy for electricity distributors in incentive ratemaking periods, in a 2006 Report:

“With regard to use of the Consumer Price Index (CPI) rather than GDP-IPI, the Board agrees with Dr. Lowry that GDP-IPI is preferable to the CPI because it tracks a more relevant set of goods and services used as inputs for production by businesses, including electricity distributors. CPI tracks the prices of consumer goods and services, whereas GDP-IPI is a broader measure of inflation that covers other relevant sectors of the economy such as capital equipment. Therefore, the Board will use the GDP-IPI as the inflation proxy for the 2nd Generation IRM.”¹⁴⁶

Overall, studying electricity prices over time on both a nominal and inflation-adjusted basis will provide a more comprehensive picture of the changes in electricity prices that occurred before and after the sector restructuring.¹⁴⁷

5.3.4 Commodity Price

As noted previously, prior to the restructuring of Ontario’s electricity sector, the price of electricity was bundled. Therefore, a stand-alone commodity price for the pre-restructuring period is not available. However, after restructuring, electricity prices were unbundled and customers began paying for the electricity commodity separately.

I compiled a number of different commodity price datasets have been compiled which will be used to highlight changes in the price of the electricity commodity over the post-restructuring period. The commodity pricing information can be found at Figure 13 (sub-section 6.2.2) and sub-section 9.2.1.

¹⁴⁶ Ontario Energy Board, 2006: 28.

¹⁴⁷ As will be discussed later, nominal electricity prices have been used as the basis for the statistical analysis as this is consistent with other academic papers that analyze electricity prices over time.

The first commodity-related dataset provides the wholesale market price for the period 2003-2012. The wholesale market price is based on a weighted average of the Hourly Ontario Electricity Price. This information was sourced from an IESO archive of historical wholesale market prices.¹⁴⁸

Another dataset compiled provides the global adjustment price for the 2005-2012 period. This information was sourced directly from an IESO archive of historical global adjustment values (both prices and total amounts collected through the global adjustment).¹⁴⁹

An average annual commodity price was calculated by summing the monthly wholesale market price and the monthly global adjustment price and then averaging the monthly values over a given year.

The next dataset provides the tiered RPP price, for the period 2003-2012, that would be applicable to small volume consumers in Ontario. This information was taken directly from the OEB's archived RPP prices.¹⁵⁰

Finally, a dataset which provides the RPP ToU price, for the period 2006-2012, was developed. A weighted average ToU price was calculated by applying the average consumption for each of the daily consumption periods (i.e. off, mid, and on peak times) to the ToU prices. The ToU prices were sourced from the OEB's RPP archive¹⁵¹ and the average consumption information was sourced from a ToU pricing backgrounder issued by the OEB in 2013.¹⁵²

¹⁴⁸ Independent Electricity System Operator, 2014d.

¹⁴⁹ Independent Electricity System Operator, 2014e.

¹⁵⁰ Ontario Energy Board, 2014c.

¹⁵¹ Ibid.

¹⁵² Ontario Energy Board, 2013a: 1.

5.3.5 Global Adjustment

As discussed previously, the global adjustment is designed to capture the difference between the revenues generated through the wholesale market price and the actual amount paid to contracted and regulated generators (OPG prescribed assets, OPA contracted generation, and NUGs) for their output.¹⁵³

A dataset has been developed which sets out the total amount collected through the global adjustment charges over the period 2008-2012. It also highlights the proportion of the total costs that are associated with each generation category (OPG, OPA, and NUGs). This information can be found in Figure 12 (sub-section 6.2.2).

I sourced the information for this dataset directly from an IESO archive of historical global adjustment values (both prices and total amounts collected through the global adjustment).¹⁵⁴

5.3.6 Transmission Price

As noted previously, prior to the restructuring of Ontario's electricity sector, the price of electricity was bundled. Therefore, a stand-alone transmission price for the pre-restructuring period is not available. However, after restructuring, electricity prices were unbundled and customers began paying for the transmission services separately.

I compiled a dataset which sets out Ontario's uniform transmission rates for the period 2002-2012. The information for this dataset was sourced from a number of Ontario Energy Board Decisions and Rate Orders.¹⁵⁵ This information can be found at sub-section 9.3.1.

¹⁵³ Independent Electricity System Operator, 2014a.

¹⁵⁴ Independent Electricity System Operator, 2014e.

¹⁵⁵ Ontario Energy Board, Uniform Transmission Rate Decisions and Rate Orders, 2002-2012:

(a) EB-1999-0055
(b) EB-2005-0241
(c) EB-2007-0759

5.3.7 Distributor - Return on Equity

I developed a dataset which highlights the average Return on Equity (“RoE”) for all the distributors in the province. The dataset covers the 2006-2012 period. The RoE information can be found at sub-section 9.4.2.

The dataset was developed by dividing the total net income (of all the distributors combined) by the total equity of all the distributors in the province for each year that is included in the time series. This provides the RoE in percentage terms. The RoE information was sourced from the Ontario Energy Board’s Yearbook of Electricity Distributors.¹⁵⁶

It is important to note that prior to the restructuring all returns were treated as retained earnings. Essentially, any profits that a distributor earned in the years prior to the sector restructuring were held by the distributor to be used to fund utility requirements (i.e. expansion projects, reliability projects, etc.). However, after the restructuring, returns earned by distributors were paid to shareholders in the form of dividends. As will be discussed in sub-section 9.4.2, the differential treatment of returns, as between the pre- and post- restructuring periods, applies upwards pressure on distribution prices in the post-restructuring period.

5.3.8 Distributor – Operations, Maintenance and Administrative Expenses

This dataset provides the distribution-related Operations, Maintenance and Administrative (“OM&A”) costs per customer averaged across all the distributors in the province. The dataset covers the period 1990-1997 and 2006-2012. This information can be found at sub-section 9.4.4. The same issue, as discussed earlier, regarding a lack of data being available for the 1998-2005 period is applicable to this dataset.

-
- (d) EB-2008-0113
 - (e) EB-2008-0272
 - (f) EB-2010-0002
 - (g) EB-2011-0268
 - (h) EB-2012-0031

¹⁵⁶ Ontario Energy Board, Yearbook of Electricity Distributors, 2006-2012.

I developed the dataset by dividing the total OM&A expenses of all the distributors in the province by the total number of customers served. This provides the average OM&A expenses incurred by distributors on a per customer basis. Once again, the dataset ignores any differences between the costs incurred to serve customers that are in different rate classes.

The OM&A information for the pre-restructuring period was sourced from Ontario Hydro's Statistical Yearbooks.¹⁵⁷ For the post-restructuring period, the OM&A information was sourced from the Ontario Energy Board's Yearbooks of Electricity Distributors.¹⁵⁸

5.3.9 Ontario Electricity Financial Corporation Revenues

I developed a dataset which sets out the revenues received by the Ontario Electricity Financial Corporation over the period 2000-2012. The information contained in this dataset can be found at sub-section 9.5.7. As noted previously, after the restructuring, the Ontario Electricity Financial Corporation was created to assume and manage the stranded debt of Ontario Hydro. It receives revenue to pay down Ontario Hydro's stranded debt through the following:

- Payments in lieu of taxes paid by OPG, Hydro One and the LDCs;
- The profits of OPG and Hydro One, in excess of the government's annual interest cost of its investment in the two companies; and
- The debt retirement charge paid by electricity consumers.

The dataset highlights the amount of money that was transferred to the Ontario Electricity Financial Corporation from each of the above revenue streams over the 2000-2012 period. The information for this time-series was sourced from the corporation's annual reports.¹⁵⁹

¹⁵⁷ Ontario Hydro, Statistical Handbooks, 1990-1997.

¹⁵⁸ Ontario Energy Board, Yearbook of Electricity Distributors, 2006-2012.

¹⁵⁹ Ontario Electricity Financial Corporation, Annual Reports, 1999-2012.

5.3.10 Debt Financing Costs

This data set provides the deemed interest rates associated with long-term and short-term debt, as established by the OEB, applicable to the LDCs. The information contained in the data set covers the period from 2000-2012 and can be found at sub-section 9.5.8.

The information was sourced from OEB Decisions and Cost of Capital Parameter updates issued by the OEB.¹⁶⁰

5.3.11 Installed Generation Capacity

This dataset highlights the total installed generation capacity in Ontario from 1983-2013. The information contained in this dataset can be found at sub-section 6.2.1. However, there are however a number of years during that period where there is no installed capacity information available.

From 1983-1992, the information is sourced from Ontario Hydro's Statistical Yearbooks.¹⁶¹ After 1992, Ontario Hydro's Statistical Yearbooks stopped reporting the installed capacity in Ontario. Total installed capacity in 1995, 1996, and 1998 data was sourced from Ontario Hydro's annual reports.¹⁶² The information for the period up to 1996 includes only capacity owned and operated by Ontario Hydro. For 1998, total installed capacity also includes non-utility generator capacity as some information regarding NUG generation is available for that year only.¹⁶³

¹⁶⁰ Ontario Energy Board, Cost of Capital Parameters Decisions (RP-1999-0034 / EB-2006-0088 / EB-2009-0084) and Cost of Capital Parameter Update Letters.

¹⁶¹ Ontario Hydro, Statistical Handbooks, 1983-1992.

¹⁶² Ontario Hydro Annual Reports, 1995, 1996 and 1998.

¹⁶³ The installed 1998 NUG capacity was cited as 2000MW in a gift given to staffers in Ontario Hydro's NUG division. After the group managed to contract for 2000MWs of capacity, the group was disbanded.

For the period 2003-2008, I derived the total installed capacity information from the IESO's Monthly Generator Disclosure Reports.^{164 165}

As the IESO stopped publishing the Monthly Generator Disclosure Reports in June 2008, there was no publically-accessible installed generation capacity information available for the 2009-2012 period. However, for 2013 the IESO website did provide the installed capacity as of October of that year.¹⁶⁶

5.3.12 Installed Generation Capacity – Ownership

This dataset provides the ownership of installed generation capacity for 1998 and 2002-2008 (as between Ontario Hydro and the NUGs for 1998 and as between OPG, Bruce Power and other private generators for 2002-2008). This information can also be found at sub-section 6.2.1.

Prior to 1998, effectively all generation capacity in the province was owned by Ontario Hydro (with the exception of some NUG capacity). As noted previously, the only NUG data that is available is for 1998. For 2002-2008, the ownership information was derived from the IESO's Monthly Generator Disclosure Reports.¹⁶⁷

5.3.13 Generation Output

This dataset was developed to provide the electricity output from generation facilities in Ontario during the period 1990-2012. The total electricity output for this period is

Above is sourced from: Ontario Hydro, Gift to staffers, Coaster inscribed with "2000MW Achievement – Non-Utility Generation."

¹⁶⁴ For each year (with the exception of 2008), the installed capacity information included in December Generator Disclosure Report was considered representative of the installed capacity for the year. For 2008, the June Generator Disclosure Report was considered representative of the installed capacity for that year (as this was final generator disclosure report issued by the IESO).

¹⁶⁵ Independent Electricity System Operator, Monthly Generator Disclosure Reports, 2003-2008.

¹⁶⁶ Independent Electricity System Operator, 2013b.

¹⁶⁷ Independent Electricity System Operator, Monthly Generator Disclosure Reports, 2003-2008.

disaggregated by the source of the output. However, there are a number of years during the noted period where there is no generation output information available. This information can be found at section 7.2.

For 1990-1992, the generation output information was sourced directly from Ontario Hydro's Statistical Handbooks.¹⁶⁸ The dataset is meant to reflect only Ontario generation, however, for the 1990-1992 period, there is likely a small amount of imported electricity included in the total (as there was no way to disaggregate Ontario Hydro's electricity purchases from other jurisdictions and purchases made from the NUGs). For the period 1993-1997, there is no generation output information available as Ontario Hydro stopped reporting this information in its Statistical Handbooks. For the 1998-2000 period, generation output information was sourced from an IESO electricity sector transition archive.¹⁶⁹ For the 2003-2012 period, the generation output information was provided by the IESO through email correspondence.¹⁷⁰

One of the categories in the generation output dataset is output sourced from oil / natural gas-fired generation facilities. For the pre-restructuring period, this category was dominated by oil-fired generation (as the only generation station in the category was the Lennox Generation Station, which was entirely fueled by oil until 1997).¹⁷¹ After the restructuring, the source fuel reflected in this category shifts to almost entirely natural gas as a number of new gas-fired generation stations came online and in 1997, Lennox was refurbished as a flex-fuel station, which means the station could use either oil or natural gas as a source fuel.¹⁷²

¹⁶⁸ Ontario Hydro, Statistical Handbooks, 1990-1992.

¹⁶⁹ Independent Electricity System Operator, 2010b.

¹⁷⁰ Independent Electricity System Operator, 2013c.

¹⁷¹ Ontario Hydro, Statistical Handbooks, 1990-1992.

¹⁷² Ontario Power Generation, 2014.

5.3.14 Generation Output – Ownership

The purpose of this dataset is to highlight the relative ownership of the electricity output in the province for the period 2003-2012 (as between OPG, Bruce Power, and other private generators). Prior to restructuring, nearly all of the electricity in Ontario was generated by Ontario Hydro (with a small amount being generated by the NUGs). The information contained in this dataset can be found at sub-section 6.2.1.

The ownership of the installed capacity, on a source-by-source basis, was applied to the generated output data to calculate the relative percentage of generated output owned by each of OPG, Bruce Power and other private generators. After restructuring, from 2003-2008, ownership information was derived from the IESO's Monthly Generator Disclosure Reports.¹⁷³ For the 2009-2012 period, ownership information was estimated (since the IESO stopped publishing its Monthly Generator Disclosure Reports). The methodology used to estimate the ownership of generation output over the 2009-2012 period is as follows.

For the nuclear and coal generation categories, ownership percentages have been held at the 2008 level and applied to the output from those generation sources for the years 2009 to 2012. Maintaining the relative 2008 ownership levels for these categories is appropriate as no companies were building new capacity in these categories over the noted period.¹⁷⁴

For the oil / natural gas category, the amount of output deemed to be owned by OPG was held at the 2008 level in absolute terms (as OPG owns a single generation station – the Lennox Generation Station, which is a flex-fuel oil / natural gas generation facility). However, over this period, private generators were building new gas-fired generation capacity. Therefore, OPG's relative ownership in this category declines as additional capacity was brought online.

¹⁷³ Independent Electricity System Operator, Monthly Generator Disclosure Reports, 2003-2008.

¹⁷⁴ Note however, that Bruce Power's Nuclear Units 1 & 2 did come online in October 2012 but this does not materially impact the nuclear output information as they were only operating for 3 months of the year.

In regard to the hydroelectric category, there has likely been a modest amount of hydroelectric capacity coming online that is owned by private generators over the 2009-2012 period. However, the extent to which this is the case has been difficult to establish. Therefore, the relative ownership of hydroelectric generation has been held consistent after 2008. This likely does not materially impact the ownership analysis completed in this paper.

Finally, regarding the wind and “other” generation sources categories, private generators owned 100% of the generated output from these sources until 2008 (when the actual ownership data was no longer reported by the IESO). Given that OPG and Bruce Power did not construct any capacity in these categories over the 2009-2012 period, the private generators were assigned 100% of the generated output from these sources for the noted period.

5.3.15 Average Use of Electricity

I developed the average use datasets to highlight the change in average monthly electricity consumption of electricity on a per customer basis over the 1990 to 2012 period. There are two distinct average use datasets which have been developed:

- (a) Residential customers only; and
- (b) All utility customers.

The information contained in these datasets is discussed in section 7.3.

The information for the 1990 to 1997 period was sourced from Ontario Hydro's Statistical Handbooks.¹⁷⁵ The 1990-1997 average use data excludes those customers that were directly served by Ontario Hydro (as average use information was not available for Ontario Hydro's retail customers). The same issue, as discussed earlier, regarding a lack of data being available for the 1998-2005 period is applicable to this

¹⁷⁵ Ontario Hydro, Statistical Handbooks, 1990-1997.

dataset. The information for the 2006-2012 period was sourced from Ontario Energy Board's Yearbooks of Electricity Distributors.¹⁷⁶

5.4 Statistical Analysis

The underlying data used for the statistical analysis, described below, is the nominal “all-in” electricity price dataset, for the period 1983-2012, discussed above in subsection 5.3.1. As noted previously, there is a gap in actual data for the period 1998-2005. In order to maintain a continuous dataset, electricity prices for the 1998-2005 period have been derived by grossing up the 1997 “all-in” electricity price to reflect the average annual price increase for the period 1997 to 2006. I determined that it is best to use nominal prices for the statistical analysis because this is consistent with other academic papers that were focused on analyzing electricity prices over time.¹⁷⁷

To study the impact that the electricity sector restructuring had on electricity prices, I generated two restructuring related dummy indicator variables. First, a restructuring dummy indicator variable was created to come into effect after 2006. This variable reflects the start of the post-restructuring period (where actual data is available). As the restructuring dummy indicator variable is set to come into effect in the post-2006 period, the statistical models utilized understand the post-restructuring period to have begun in 2006. As discussed, the post-restructuring period actually began in 1998. However, given the lack of data available for the 1998-2006 period, it would have been impossible to get useful results from a model which had the restructuring dummy indicator variables come into effect for the post-1998 period (as all the pricing information for the 1998-2006 period are interpolated). This means that the restructuring dummy indicator variable, in practice, is capturing the impact of both the restructuring and certain post-restructuring changes.

¹⁷⁶ Ontario Energy Board, Yearbook of Electricity Distributors, 2006-2012.

¹⁷⁷ The following, all of which use nominal electricity prices as a basis for analysis, were reviewed: Misiolek et al., (2006), Cartea and Figueroa (2005), and Gythrie and Videbeck (2007).

When looking at the results from a basic ordinary least squares regression on the restructuring dummy indicator variable, this variable shows whether a permanent shift in electricity prices occurred after the restructuring (i.e. a change in the intercept). When looking at the results from an Autoregressive Integrated Moving Average (“ARIMA”) (or Autoregressive Integrated Moving Average with Explanatory Variable – “ARIMAX”) regression on this variable (when the number of non-seasonal differences is set to 1), this variable shows a permanent shift in changes to electricity prices after the restructuring.

Second, a restructuring / time interaction variable was generated. This variable multiplies the restructuring dummy indicator variable by the year. When looking at the results from a basic ordinary least squares regression on the restructuring / time interaction variable, this variable shows the changes to electricity price increases (i.e. a change in the slope) after the restructuring. When looking at the results from an ARIMA (or ARIMAX) regression on this variable (when the number of non-seasonal differences is set to 1), this variable highlights how the increases in electricity prices changes over time.

I also created another set of dummy indicator variables for purposes of carrying out statistical analysis on electricity prices. A dummy indicator variable (the “gap dummy variable”) was generated to come into effect in 1998 and run until 2006 to reflect the pricing data that is not based on actual electricity prices (and rather has been interpolated for the purposes of building a continuous dataset of electricity prices which is required by both the ARIMA and ARIMAX regression models to function correctly). An interaction variable was also generated which multiplies the gap dummy variable by the year. This variable was generated largely to segregate the data that is not based on actual information from the rest of the post-restructuring data that is based on actual electricity prices for the relevant year. The restructuring dummy variable and its interaction variable with time, discussed above, is the focus of the statistical analysis.

In addition to the above noted dummy variables, three additional independent variables were considered as part of the regression analysis in order to control for factors which may impact electricity prices and are not related to the restructuring.

The first independent variable which was added to the regression model was time (as it is generally expected that electricity prices will increase over time). The second independent variable which was added was designed to be reflective of changes to the economy (as represented by Canada's GDP) (i.e. a GDP proxy variable).^{178 179} The third independent variable added is reflective of Ontario weather in each year of the time series (i.e. a weather proxy variable). Weather information was sourced from the Government of Canada's Climate Database.¹⁸⁰ Heating Degree Days ("HDDs") were added to Cooling Degree Days ("CDDs") to calculate Total Degree Days ("TDDs").¹⁸¹ Pearson weather station information was assumed to be representative of Ontario weather.

I used a few different statistical techniques in the analysis of the "all-in" electricity prices over the 1983-2012 period. First, a basic ordinary least square regression was used to estimate the significance that the restructuring had on electricity prices over the post-restructuring period. The regression was run on a model that included the electricity price as the dependent variable and the restructuring dummy variables, the gap dummy variables, GDP and TDD as the independent variables.

After the regression was run on the full model, I reviewed the correlation between the independent variables. That analysis highlighted that the GDP proxy variable is correlated to the time variable. Therefore, I ran the regression with the GDP proxy variable excluded from the model. This model, with the GDP proxy variable excluded, had the highest R-squared value. Considering the R-squared value explains the goodness of fit of the model¹⁸², I determined that the best model to use to analyze the impact that the restructuring had on electricity prices excluded GDP.

¹⁷⁸ This information was sourced from CANSIM Table 380-0102 and reflects Canada's GDP at market prices for the period 1983-2012.

¹⁷⁹ Statistics Canada, 2014.

¹⁸⁰ Government of Canada, 2014.

¹⁸¹ The HDD and CDD balance point was set at 18 degrees Celsius.

¹⁸² The adj. R-squared explains how well the model fits the data while penalizing adding independent variables which do not explain much of the dependent variable.

After I completed the regression analysis, the next issue that required attention was determining whether the time-series of electricity prices exhibited autocorrelation problems. Given that the “all-in” electricity price dataset underpinning the model is a time-series of electricity prices, it is likely that autocorrelation problems exist in the dataset as the variables that drive electricity prices, largely, the costs of generating, transmitting and distributing electricity, are correlated on a year-to-year basis.

To check for autocorrelation problems in the model, I utilized the Durbin Watson Test. The Durbin Watson Test looks for autocorrelation problems in a time-series by checking for the presence of autocorrelation in the residuals from a regression analysis. The Durbin Watson Test provided inconclusive results as to whether there were autocorrelation problems in the model. However, given the nature of the data being analyzed, regardless of the outcome of the Durbin Watson test, it is highly probable that an autocorrelation problem exists.

Next, I utilized the Prais-Winsten estimator to try to overcome the expected autocorrelation problems in the dataset. The Prais–Winsten estimator is a procedure designed to take care of the serial correlation of type AR(1) in a model.

The Prais-Winsten estimator was not entirely successful at addressing the expected autocorrelation problems in the dataset. As the Prais-Winsten only addresses serial correlation problems of type AR(1), I determined that that the dataset was likely exhibiting higher-order auto-regressive problems.

The ARIMA model allows more extensive parameters to be set in the model, which can potentially deal with higher-order auto-regressive problems. Therefore, I used the ARIMA model to possibly generate a more relevant regression model for the dataset. In the ARIMA model the following parameters can be set:

- The number of autoregressive terms;
- The number of nonseasonal differences; and
- The number of lagged forecast errors in the prediction equation.

I ran a number of tests, based on the autocorrelation function and the partial autocorrelation functions, to determine the appropriate parameters to set for the ARIMA model. I determined that the number of autoregressive terms associated with the electricity price data underpinning the regression analysis was 3, the number of nonseasonal differences was 1, and the number of lagged forecast errors in the predication equation was 1. Overall, the ARIMA (3,1,1) model best fit the dataset.

After I determined that the ARIMA (3,1,1) model best fit the dataset, the ARIMAX (3,1,1) model was run on the full dataset (i.e. all the dummy variables and TDD).¹⁸³ The results of the ARIMAX model form the basis for the conclusions regarding the impact that the sector restructuring had on electricity prices, which are set out later in the paper.

A full discussion of the results of the statistical analysis completed is set out at section 8.4.

5.5 Limitations

This paper is entirely focused on the restructuring of Ontario's electricity sector and the impacts that the restructuring, and post-restructuring changes, had on electricity consumers (from both an economic and environmental perspective). In other words, the paper essentially encompasses a case study of Ontario's electricity sector restructuring.

However, what my paper does not do, and in fact cannot do, is compare Ontario's restructured electricity sector to a hypothetical Ontario electricity sector that was never restructured. Would electricity prices have been lower if the monopoly model continued? Would the coal phase out still have occurred if the sector was never restructured? These are the types of questions that will remain unanswered as it is not possible to know what the sector would have looked like today if it was never restructured. This is the "unsolvable counterfactual problem" that looms over the analysis undertaken in this paper.

¹⁸³ The ARIMA model is known as an ARIMAX model when independent variables are included in the regression analysis.

The best way to address the unsolvable counterfactual problem is to complete a comparative analysis as between Ontario's electricity sector restructuring and other jurisdictions that have, and have not, restructured their electricity sectors. This could provide answers to questions about whether the restructuring alone caused the changes that occurred in the sector (or whether they were likely to occur anyway). For example, as will be discussed later, Ontario's supply mix has shifted away from coal and relies more heavily on natural gas-fired and renewable energy sources. It would be interesting to analyze the electricity sectors of a few other jurisdictions (both restructured in a manner similar to Ontario and traditional monopoly models) to determine whether those jurisdictions are also moving away from carbon-intensive generation sources. Another interesting comparison would be to look at a number of jurisdictions with restructured electricity sectors and try to determine whether all of these jurisdictions have experienced higher rate increases in the period after restructuring. An answer to this question would provide insight into whether restructuring, and the necessary changes that go along with restructuring, cause electricity prices to increase.

Given the time constraints on completing the M.A in Interdisciplinary Studies program, and the difficulty of gathering, and analyzing, the information that was used in this paper, I did not attempt to compare Ontario's electricity sector to electricity sectors in other jurisdictions. This is an intentional limitation of my paper. While a comparative analysis research project would be interesting to complete, it was never contemplated as part of the analysis set out here. However, the information and analysis that is provided by this paper provides a researcher with the necessary information to compare Ontario's electricity sector with the electricity sectors of other jurisdictions.

Another limitation of my paper is with regard to the comparison of environmental benefits to their associated financial costs. As I will discuss later, a number of sector changes that arose out of post-restructuring government policies have resulted in a greener electricity sector in Ontario. However, these environmental benefits have come at a cost in terms of increased electricity prices. I recognize that there are numerous pricing schemes for greenhouse gas equivalents (and the reduction of airborne health hazards). However, Ontario does not have carbon trading market and there is no

universally accepted formula for calculating the value of environmental benefits in financial terms. On that basis, any attempt to weigh the environmental benefits, quantitatively, against the financial costs would cause unnecessary debate in regard to the weighting of these benefits and costs. Therefore, I have not, on a quantitative basis, attempted to weigh the environmental benefits in terms of the financial costs. For the purposes of the conclusions set out in my paper, the environmental gains that arose out of post-restructuring policies of government are considered, on a qualitative basis, to be beneficial to consumers. However, a quantitative analysis of the environmental benefits (and costs) of that arose out of the post-restructuring policies of government would be an interesting project to complete. The information provided in my paper provides a strong basis to begin that analysis.

5.6 Conclusion

The above section provided a detailed description of all of the datasets that were developed for use in the analysis undertaken later in this paper. The rationale for the timeframes selected over which changes to Ontario's electricity prices are analyzed was provided. The inflation adjustment methodology used in the electricity pricing analysis and the rationale for selecting the methodology was also discussed. The statistical methodology used to analyze the price data was described. Finally, the limitations of the analysis completed in my thesis paper were set out.

6. Competition Analysis

6.1 Introduction

One of the objectives of restructuring, as set out in the Government's White Paper, was to reduce electricity prices through the introduction of competition in generation. Another objective was to provide customer choice in retail electricity supply in order to encourage greater product and service innovation and price discipline on electricity providers. The first part of this chapter will examine competition in electricity supply followed by a similar evaluation of the retail market.

6.2 Competition in Generation

Prior to the electricity sector restructuring, Ontario Hydro owned and operated almost all of the generation capacity (and consequently generated almost all of the electricity) in Ontario. After the restructuring, OPG, a provincially owned entity, continued to own and operate the majority of the generation capacity (and generate most of the electricity) in the province, however, to a much lesser extent than Ontario Hydro. In the following section I will provide a breakdown of the ownership of Ontario's generation capacity and generated output. I will also look at the pricing and contracting arrangements for Ontario's generators in order to explain the operation of Ontario's wholesale electricity market and provide a basis for analyzing whether there is true competition for electricity generation in Ontario.

6.2.1 Ownership of Installed Capacity and Generated Output

In the period immediately after the enactment of the *Energy Competition Act*, OPG and the provincial government signed the Market Power Mitigation Agreement. As discussed earlier, the agreement resulted in OPG selling / leasing some of its generation assets

(including some of its nuclear portfolio and some of its price-setting hydroelectric assets).¹⁸⁴

Figures 5, 6 and 7 show the relative ownership of the province's generation capacity in 1998 (immediately before the restructuring), 2003 (the year after the wholesale electricity market opened), and 2008 (10 years after the sector restructuring began).

Figure 5 - Installed Generation Capacity by Owner (1998)¹⁸⁵

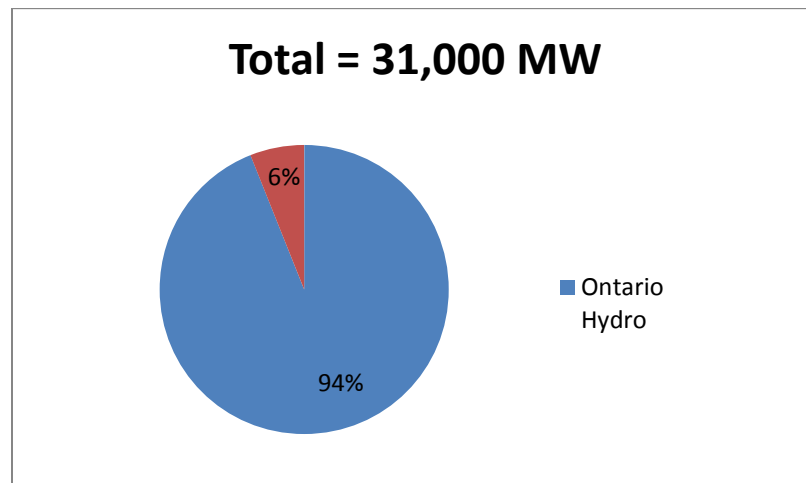
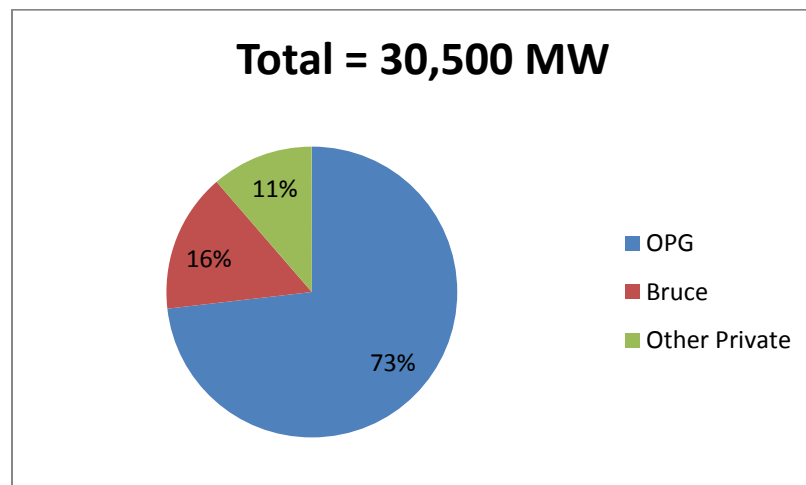


Figure 6 - Installed Generation Capacity by Owner (2003)¹⁸⁶

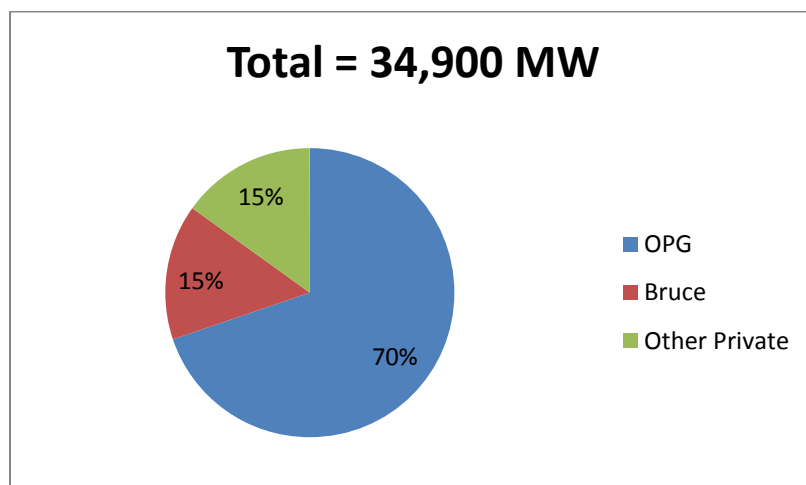


¹⁸⁴ Treblicock and Hrab, 2006: 424.

¹⁸⁵ Ontario Hydro, 1998.

¹⁸⁶ Derived from Independent Electricity System Operator, Monthly Generator Disclosure Report, 2003.

Figure 7 - Installed Generation Capacity by Owner (2008)¹⁸⁷



As can be seen in the charts above, the amount of installed capacity owned by Ontario Hydro immediately before the restructuring was 94%, the amount of installed capacity that was owned by OPG in 2003, after market opening, was 73%, and the amount of installed capacity owned by OPG in 2008 was 70%. This shows that the market dominance of OPG decreased after market opening (as a result of the Market Power Mitigation Agreement). However, OPG in 2008, still owned and operated the vast majority of installed generation capacity in the province.

Figures 8, 9 and 10 show the relative ownership on a generated output basis for the years 2003, 2008 and 2012. There is no information available regarding the ownership of the generated output prior to the restructuring (i.e. between Ontario Hydro and the non-utility generators). However, given that the NUGs owned approximately 6% of the total installed generation capacity in 1998, it would be reasonable to estimate that they produced somewhere in the range of 3%-8% of Ontario's electricity in that year.

¹⁸⁷ Derived from Independent Electricity System Operator, Monthly Generator Disclosure Report, 2008.

Figure 8 - Generated Output by Owner (2003)¹⁸⁸

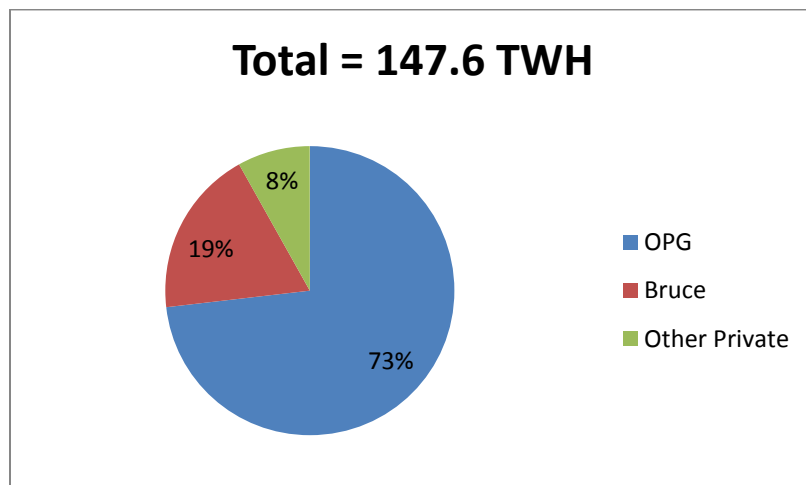
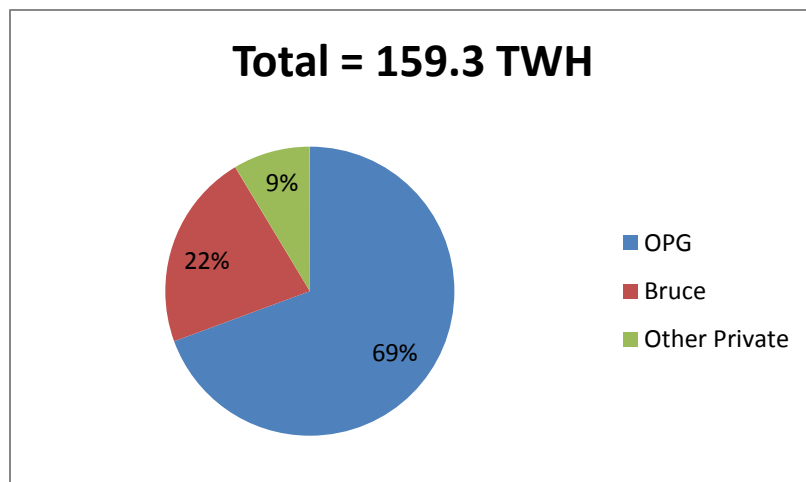


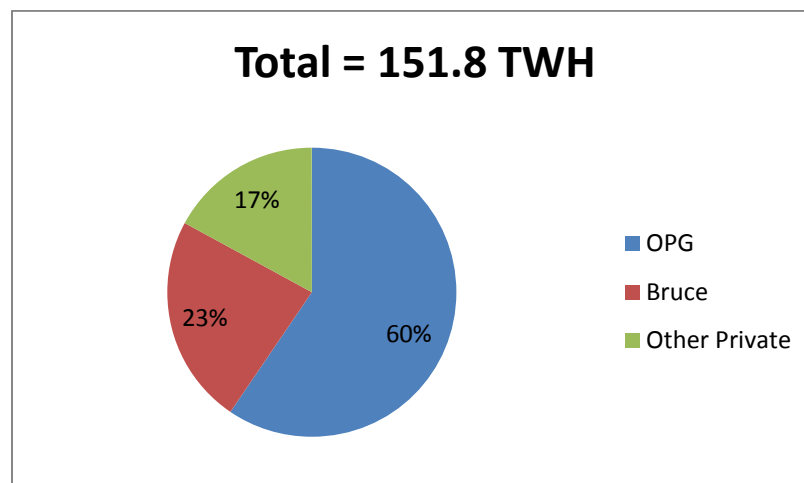
Figure 9 - Generated Output by Owner (2008)¹⁸⁹



¹⁸⁸ Derived from Independent Electricity System Operator, 2013c & Independent Electricity System Operator, Monthly Generator Disclosure Report, 2003.

¹⁸⁹ Ibid.

Figure 10 - Generated Output by Owner (2012)¹⁹⁰



The charts above highlight that on an output basis, private generators (Bruce Power and other private owners) have started to produce more of the province's electricity supply over the years (2003 to 2012). This is primarily due to the phase out of coal, the increased reliance on gas fired generation (which is largely being developed by private companies), and the refurbishment of the Bruce Nuclear facilities. A discussion of the shift in Ontario's supply mix is set out later in this paper.

While the market dominance of OPG has reduced over the post-restructuring years, on both an installed capacity and generation output basis, it still holds a dominant market share.

6.2.2 Generation Payment Arrangements, the Role of the Global Adjustment and OPA Contracting Practices

In order to understand the manner in which generators are paid for their output and how those payment arrangements impact the competitive nature of Ontario's electricity sector, it is necessary to understand how Ontario's wholesale electricity market operates and more specifically how the wholesale market price is set by the IESO.

The first step in setting the wholesale market price is the IESO forecasting the amount of electricity that will be demanded the next day (the "day-ahead forecast"). The IESO

¹⁹⁰ Derived from Independent Electricity System Operator, 2013c.

publishes its demand forecast on its website so generators have an idea of how much electricity will likely be required by the IESO.

Generators then review the forecasted demand and submit their offers to the IESO. The offers provided by the generators stipulate the amount of electricity they are willing to supply and the minimum price that they are willing to take for the offered supply.

The IESO then reviews the offers made by the generators and matches supply with the forecasted demand. When setting the wholesale market price, the IESO first accepts the lowest-cost offers and then subsequently accepts higher-cost offers until sufficient supply has been acquired to meet the forecasted demand. However, regardless of the actual offer submitted, all generators are paid the “market clearing price”, which is based on the last offer accepted (or, in other words, the highest cost offer that was accepted by the IESO). The generators whose offers were accepted are then dispatched by the IESO to begin supplying electricity to the grid.¹⁹¹

The above explains how the IESO sets the wholesale market price for electricity and highlights that all generators receive the market clearing price for their output. However, the wholesale market price does not reflect the entire price paid to generators for their output. With the exception of OPG merchant generation capacity (which is a very small subset of OPG’s generation assets), all generators in the province are paid either a regulated or contracted price for their electricity.¹⁹² Typically, the market price only covers a portion of the regulated or contracted price owed to a generator; the remainder is covered through the global adjustment.

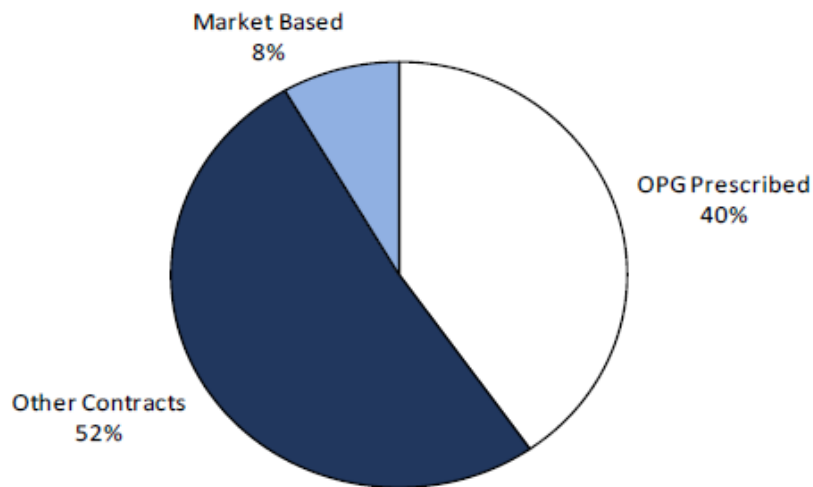
Figure 11, which was published as part of the OEB’s November 2011 to October 2012 Regulated Price Plan Report, shows that only about 8% of Ontario’s generated output was expected to be paid for entirely at the wholesale market price.¹⁹³

¹⁹¹ Independent Electricity System Operator, 2014f.

¹⁹² C.D. Howe Institute, 2013b: 8-9.

¹⁹³ Ontario Energy Board, 2011a: 20.

Figure 11 - Ontario Generation Payment Arrangements (Oct. 2011 to Nov. 2012)¹⁹⁴



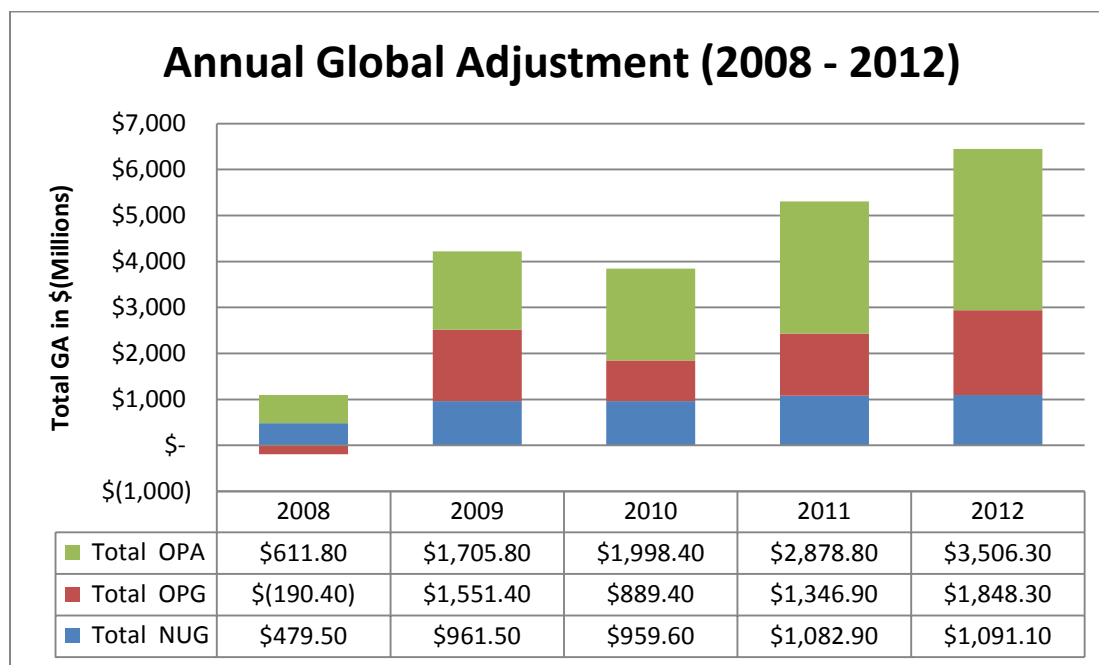
In practice, the fact that very little of Ontario's generated output is paid for entirely based on the wholesale market price means that almost all of the generators in the province have an incentive to make supply offers to IESO at a very low price (or even at a negative price, known as a "negative bid") in order to get dispatched by the IESO. When a generator is dispatched, it receives the revenues that arise from the market price and the remainder of the contracted or regulated price it is owed is covered by payments through the global adjustment.¹⁹⁵ As such, the wholesale market price means very little to the vast majority of generators.

Figure 12 sets out the total amount collected through the global adjustment charges for each year during the 2008 - 2012 period. It also highlights the proportion of the total costs that are associated with each generation category (OPG, OPA, and NUGs).

¹⁹⁴ Ibid.

¹⁹⁵ As noted previously, the global adjustment is designed to capture the difference between the revenues generated through the wholesale market price and the actual amount paid to contracted / regulated generators for their output.

Figure 12 – Annual Global Adjustment Balance (2008 - 2012)¹⁹⁶

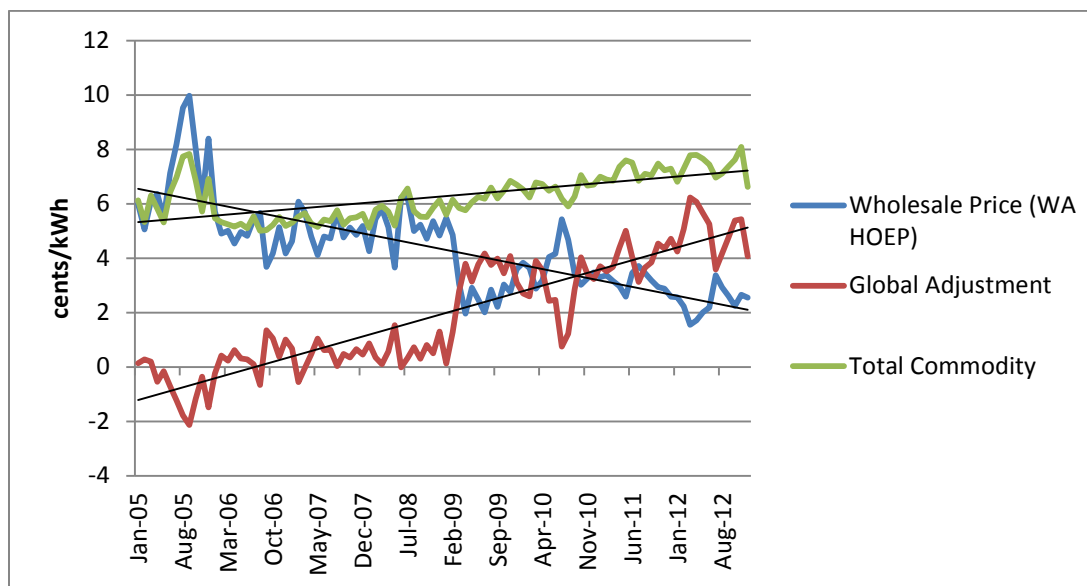


The above chart highlights that, on an aggregate basis, the amount collected through the global adjustment has been increasing steadily over the 2008-2012 period. Total revenues collected through the global adjustment have increased from approximately \$900.9 million in 2008 to \$6.4 billion in 2012. The difference between the amount collected through the wholesale market electricity price and the payments to the OPA contracted generators represents the largest contributor to the global adjustment balance in each year over the period. This chart shows that the wholesale market price is covering significantly less than the actual cost of generation each year.

Figure 13 shows the electricity commodity price for the period 2005 – 2012 (in total and disaggregated into two parts, the wholesale market price and the global adjustment price). It shows that the total commodity price has been gradually increasing since 2005. During the same time period, the wholesale market price has been declining and the global adjustment price has been increasing. The significance of this is discussed below.

¹⁹⁶ Independent Electricity System Operator, 2014e.

Figure 13 - Ontario Commodity Price (2005 - 2012)¹⁹⁷



In late 2010, a fundamental shift occurred whereby the global adjustment was recovering more of the actual commodity cost than the wholesale market price. This implies that the wholesale market price is recovering less than half of the actual commodity cost and that the contracted and regulated prices paid for generation are currently significantly higher than the amount recovered through the wholesale market rate. Therefore, the concept that generators are competing, on a price basis, to provide electricity to the grid is not accurate. The market price means very little when over 90% of generation is paid for based on contracted or regulated prices.

Currently, competition, in the generation sector, is only seen to any real extent in terms of private generators competing for generation contracts from the OPA. The OPA has a number of ongoing procurement programs, which are designed to attract generation projects for the province. At the time of drafting, the OPA was seeking to procure supply in the following areas¹⁹⁸:

¹⁹⁷ Derived from Independent Electricity System Operator, 2014d and Independent Electricity System Operator, 2014e.

¹⁹⁸ Note that the types of generation sources that the OPA is seeking to develop, through its contracting practices, can change, at any time, based on government priorities (which are communicated to the OPA through Ministerial directives).

- Small-scale renewable generation (capacity of less than 500kW) - This generation is being procured under the Feed-in Tariff program (10kW – 500kW projects) and the MicroFIT program (<10kW). The Feed-in Tariff and MicroFIT programs offer a standardized price for a number of different sources of renewable generation. Prospective generators can apply for Feed-in Tariff contracts through standard applications, which are evaluated by the OPA to determine whether a contract should be awarded to the prospective generator. The OPA describes the selection process as open and fair.^{199 200}
- Large-scale renewable generation (>500kW) – This generation is being procured through a competitive request for proposal process. The current phase for large scale renewable generation is an early stage. But the OPA has set out some preliminary concepts that it may use for the evaluation of the proposals filed. The OPA stated that it expects that the rating criteria will include: development experience, financial capability, community engagement, project due diligence, economic participation from other entities, and resource availability.²⁰¹
- Hydroelectric Supply (>500kW) – The OPA is currently in the process of developing a standard offer program for the contracting of new hydroelectric supply.²⁰²
- Combined heat and power Supply (<20MW) – The OPA is currently in the process of developing a standard offer program for the contracting of new

¹⁹⁹ Ontario Power Authority, 2014a.

²⁰⁰ The OPA evaluates the Feed-in Tariff applications based a number of eligibility requirements which include: transmission / distribution connection availability, domestic content requirements (for some types of technologies), holding certain land rights, and other relevant requirements. Projects can also be granted priority points, which are used for ranking projects relative to other potential projects. Priority points can be granted by the OPA if the project is a community / aboriginal / public sector participatory project, has municipal or aboriginal support, and if the project provides certain system benefits.

The above is sourced from: Ontario Power Authority, 2013a: 4-8, 21-27.

²⁰¹ Ontario Power Authority, 2014b and Ontario Power Authority, 2014c: 1.

²⁰² Ontario Power Authority, 2014d.

combined heat and power projects (also known as “cogeneration”).²⁰³ It is expected that the standard offer program for these types of projects will prioritize applications based on a bid-down relative to a standard price.²⁰⁴

Previous sources of electricity supply that OPA procured through its contracting practices include: Bio-energy, solar, wind, hydroelectric, combined-cycle natural gas, combined heat and power natural gas, and nuclear.²⁰⁵

The manner in which the OPA evaluates applications for supply contracts includes a framework whereby a prospective generator persuades the OPA, on the basis of the location, connection potential, domestic content, community support, price, and other project specific factors, that its proposed project should be approved for a long-term generation contract. It can be said that the contracting practices of the OPA applies some level of competition amongst prospective generators to Ontario's electricity sector. However, after a prospective generator has signed a supply contract with the OPA, the generator really does not need to compete, in any real way, to provide electricity to consumers.

Overall, given the amount of generation that is subject to contracted, or regulated, payments, the related fact that the wholesale market price means very little to generators and the continued dominance of OPG in the generation sector, it can be concluded that there is very little competition amongst existing generators. The only real competition in the generation sector occurs among companies that are competing for supply contracts from the OPA.

This conclusion is not surprising. A true free market for wholesale electricity only operated from market opening on May 2002 until December 2002 when the government froze electricity rates. After this short market experiment, the “hybrid model” for Ontario's electricity sector was introduced. The “hybrid model” included a wholesale

²⁰³ Combined Heat and Power projects utilize natural gas-fired generation plants to produce both electricity and heat.

²⁰⁴ Ontario Power Authority, 2014e and Ontario Power Authority 2014f: 6.

²⁰⁵ Ontario Power Authority, 2014g.

market system for electricity supply (where generators are required to make offers to the IESO to supply electricity to the market). However, over the years, the OPA was regularly directed by government to procure electricity supply for the province, from a number of different sources, under long-term fixed-price contracts. As noted above, by 2012, over 90% of Ontario's generated output was priced at contracted (or regulated) prices. So while any given generator is making bids to supply its generated output into the wholesale market, the bid price made by the generator is not meaningful because the generator is assured that it will be paid the full contracted, or regulated, price for its electricity supply. As such, the wholesale market largely operates as a dispatch tool for the IESO and generators are not competing on a price basis to supply electricity to consumers.

Through its policies directed at procuring generation capacity under long-term contracts, the government effectively abandoned its original plan to have competition drive the wholesale electricity market.

6.3 Customer Choice in Retail Supply

Prior to restructuring, consumers could only purchase electricity from their local MEU.²⁰⁶ Now customers have the option of purchasing electricity under the Regulated Price Plan from their LDC (known as standard supply or RPP) or from a retail electricity provider. The following section provides a breakdown of the number of customers that have elected to purchase their electricity from retailers. In addition, I will provide a comparison of the electricity prices paid by retail customers and standard supply customers. Finally, I will discuss the purpose and rationale for the enactment of the *Energy Consumer Protection Act*, which addresses issues associated with electricity retailers.

²⁰⁶ Note that the following customers purchased their electricity directly from Ontario Hydro: (a) customers of Ontario Hydro's retail business (which provided service to certain areas of the province); and (b) large volume transmission connected customers.

6.3.1 Retail Options and Number of Retailers

Retailers offer fixed-price and fixed-term contracts for the electricity commodity only. All of the other line items on the electricity bill, such as distribution and transmission services, are still purchased through the LDC. Typically, electricity retailers market their contracts as a way that consumers can ensure that their electricity prices remain stable over a fixed period of time.

For example, Active Energy, on its website, states:

...when you sign up with Active, your rates won't change from month to month... [Y]ou are locked into a fixed pricing agreement, which is a comforting thought in today's volatile energy market.²⁰⁷

Direct Energy, on its website, states:

Sign up for the Green Fixed Price Electricity Plan and avoid potential electricity price changes. Protecting your household against potential electricity price increases is always a good decision and it makes sense to secure a good plan for your home today.²⁰⁸

In 2014, there were 15 low-volume electricity retailers operating in the province. All retailers are licenced by the OEB to serve customers that consume less than 150,000 kWh of electricity annually.²⁰⁹

6.3.2 Number of Customers on Retail Contracts

There is no time series available regarding the number of customers that elected to sign retail contracts from market opening (2002) to the present day. However, there are number of sources that have indicated the number of retail customers in a given year.

Treblicock and Hrab estimated that, after market opening, approximately 1 million customers, or 23% of the total number of electricity consumers in Ontario entered into

²⁰⁷ Active Energy, 2014.

²⁰⁸ Direct Energy, 2014.

²⁰⁹ Ontario Energy Board, 2014d.

fixed price contracts with retailers.²¹⁰ The Auditor General of Ontario, in its 2011 Annual Report, estimated that in 2010 there were approximately 630,000 customers with fixed price contracts with retailers (this represents approximately 15% of the total number of energy consumers in the province).²¹¹ For 2013, the OEB's website stated that approximately 10% of Ontario consumers purchased their electricity from retailers.²¹²

Together, those estimates provide strong evidence that the number of energy consumers on retail contracts is on a declining curve since there were significantly more customers on retail contracts after market opening than there were in 2013.

6.3.3 Retail Supply - Price Comparison

One of the main selling points used to encourage customers to sign retail contracts is the long-term price stability that these contracts are expected to provide.²¹³

In practice, however, retail contracts are designed to cover only the wholesale electricity market price. Customers on retail contracts pay the global adjustment portion of the commodity price separately. Therefore, retail customers pay the actual global adjustment price applicable to a given billing period. In contrast, the RPP charge which is paid by low-volume consumers that do not sign a retail contract, is a commodity price that includes both the wholesale electricity market price and the global adjustment. Therefore, retail customers are subject to the monthly variances in the global adjustment, while RPP customers have the impact of the global adjustment smoothed over time. This means that RPP customers actually experience less variance on their monthly bills. Figure 14 illustrates that RPP customers experience less variance and also generally pay a lower aggregate price for the electricity commodity.

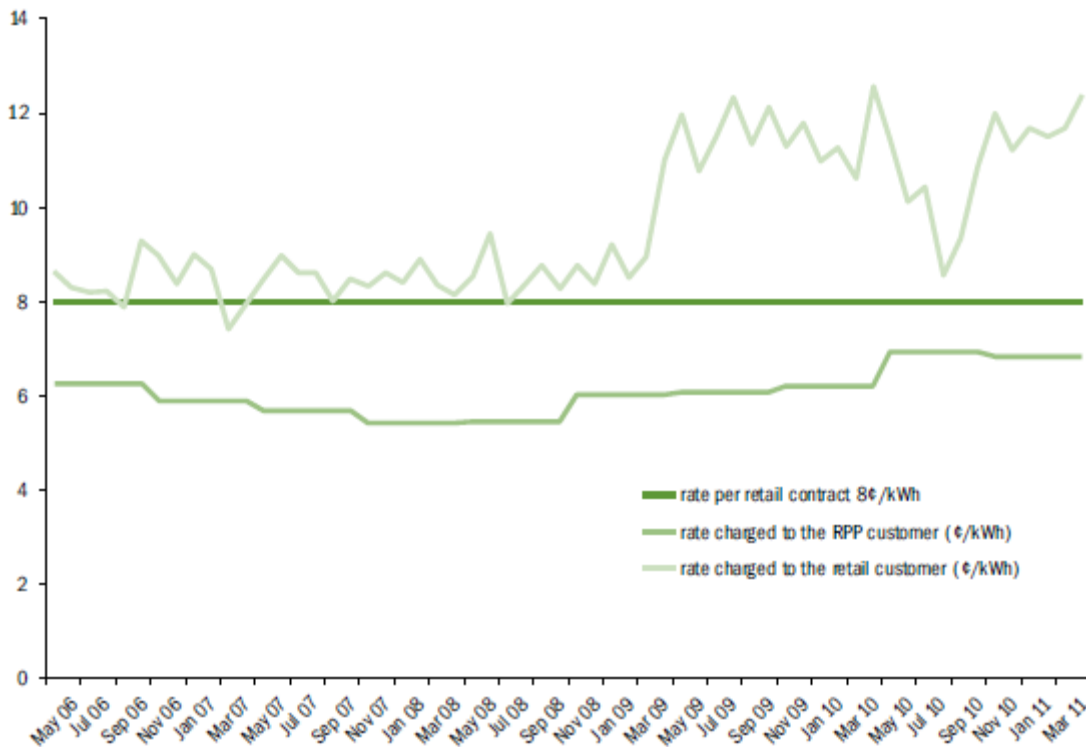
²¹⁰ Treblicock, and Hrab, 2006: 425.

²¹¹ Auditor General of Ontario, 2011: 83.

²¹² Ontario Energy Board, 2014e.

²¹³ Auditor General of Ontario, 2011: 83.

Figure 14 - Electricity Price Comparison (RPP vs. Retail Contract) (2006-2011)^{214 215}



As can be seen in the above graph, a customer that signed a contract at a price of 8 cents / kWh in 2006, would have paid a higher aggregate price for the commodity and experienced more price variance than a consumer that was subject to the RPP charge established by the OEB. Interestingly, the 8 cents / kWh price used in the above chart for illustrative purposes is actually lower than any price that the Auditor General found in a sample of retailer prices (for the years 2006-2009).

The Auditor General's sample was produced as part of its 2011 Audit of Ontario's electricity sector. It showed that retailers, at the time, were offering fixed electricity rates in the range of 8.49 cents / kWh to 10.53 cents / kWh. During the same period, the average wholesale market rate ranged from 3.2 cents / kWh to 5.2 cents / kWh. The RPP price, which includes both the wholesale market rate and global adjustment rate,

²¹⁴ Auditor General of Ontario, 2011: 84.

²¹⁵ Figure 13 provides an illustrative example of a customer that committed to a five-year fixed-price electricity retail contract at a price of 8 cents / kWh.

was set at between 5.4 cents / kWh and 6.3 cents / kWh over the same period.

Therefore, based on the auditors sample, retail customers paid anywhere from 35% to 65% more for the electricity commodity than the highest RPP rate in effect over the sample term.²¹⁶

Technically, there is customer choice in retail electricity. After market opening customers have the option of either purchasing the electricity commodity directly from their LDC or electing to sign a fixed-term, fixed-price contract with a retailer. However, as demonstrated above, the commodity price paid under a retail contract is higher than the commodity price paid by RPP customers and RPP customers enjoy greater price stability than customers on retail contracts.

6.3.4 Energy Consumer Protection Act

As noted previously, the *Energy Consumer Protection Act* came into force on January 1, 2011. The legislation was enacted by the government in response to public concerns regarding the business practices of retailers operating in Ontario. Some of the concerns related to: retailer sales practices (i.e. improper identification, pressure to sign contracts at the door, signing contracts with people other than the proper account holder, confusing language in contracts, inadequate disclosure of price comparisons), unfair cancellation policies, automatic renewals, and a general lack of accountability by retailers.²¹⁷ The majority of complaints received by the OEB are related to electricity and natural gas retailers.²¹⁸ Overall, the retail market was not believed to be operating in a manner that benefitted energy consumers in the province.

The *Energy Consumer Protection Act* caused the OEB to tighten the rules and regulations applied to electricity and natural gas retailers in the province.²¹⁹ Time will tell

²¹⁶ Ibid: 83.

²¹⁷ Andrews, 2010.

²¹⁸ Auditor General of Ontario, 2011: 70.

²¹⁹ Ontario Energy Board, 2014a.

whether these changes have helped to mitigate some of the problems present in the retail market.

6.4 Conclusion

One of the objectives of restructuring, as set out in the Government's White Paper, was to reduce electricity prices through the introduction of competition in generation. The above analysis highlights that there is very little competition amongst existing generators in Ontario's electricity sector. This conclusion is supported by the fact that OPG still holds the dominant share of installed capacity (and generated output) in the province and the vast majority of electricity supply is paid for at either contracted or regulated rates which means that the wholesale market rate means very little to generators. The lack of competition in the electricity sector is a result of the government's post-restructuring generation procurement policies.

Another objective of the restructuring was to provide customer choice in retail electricity, which the government expected would put downward pressure on commodity prices. While customer choice for retail electricity was accomplished by allowing the entry of retailers into the market, customers are not benefitting from the ability to choose their electricity supplier. Customers pay lower commodity prices, and have greater price stability, by purchasing their electricity directly from their LDC (standard supply service). In addition, there were significant issues with the business practices of the retailers, which eventually caused the government to implement the *Energy Consumer Protection Act*. Customers seem to be recognizing that they would be better off paying the RPP price as opposed to the price established under a fixed price contract as the number of customers on retail contracts has decreased from approximately 23% at market opening to 10% in 2013.

7. Supply Mix, Conservation and Smart Grid Analysis

7.1 Introduction

After the electricity sector restructuring, the government, through policy directives and legislation, provided direction regarding its expectations for Ontario's supply mix, conservation initiatives, and the development of a smart grid. Generally, the government sought to make Ontario's electricity sector more environmentally sound.

As described in sub-section 4.10, the Minister of Energy issued a Directive in June 2006 which set out the government's expectations for a reduction in peak demand to be achieved through conservation programs; an increased reliance on renewables; and the increased utilization of gas-fired generation. It also set out the government's goal to phase out coal-fired generation as soon as practical.²²⁰

The government later enacted the *Green Energy Act*. The act largely focused on promoting renewable generation (through the creation of a feed-in tariff program), promoting conservation and demand-side management, and the implementation of a smart grid in Ontario.²²¹

The following section discusses the changes to Ontario's electricity sector resulting from the government's policy directives and legislation which sought to enhance the environmental sustainability of Ontario's electricity sector. As part of this analysis, the evolution of Ontario's generation supply from the early 1990s to 2012 is discussed. I will also provide an analysis of the results of the conservation programs in effect during the post-restructuring period. In addition, I will set out an analysis of the decline in customers' average use. Finally, I will discuss the impact that the implementation of a smart grid has had on energy consumption.

²²⁰ Dwight Duncan, 2006: 1-2.

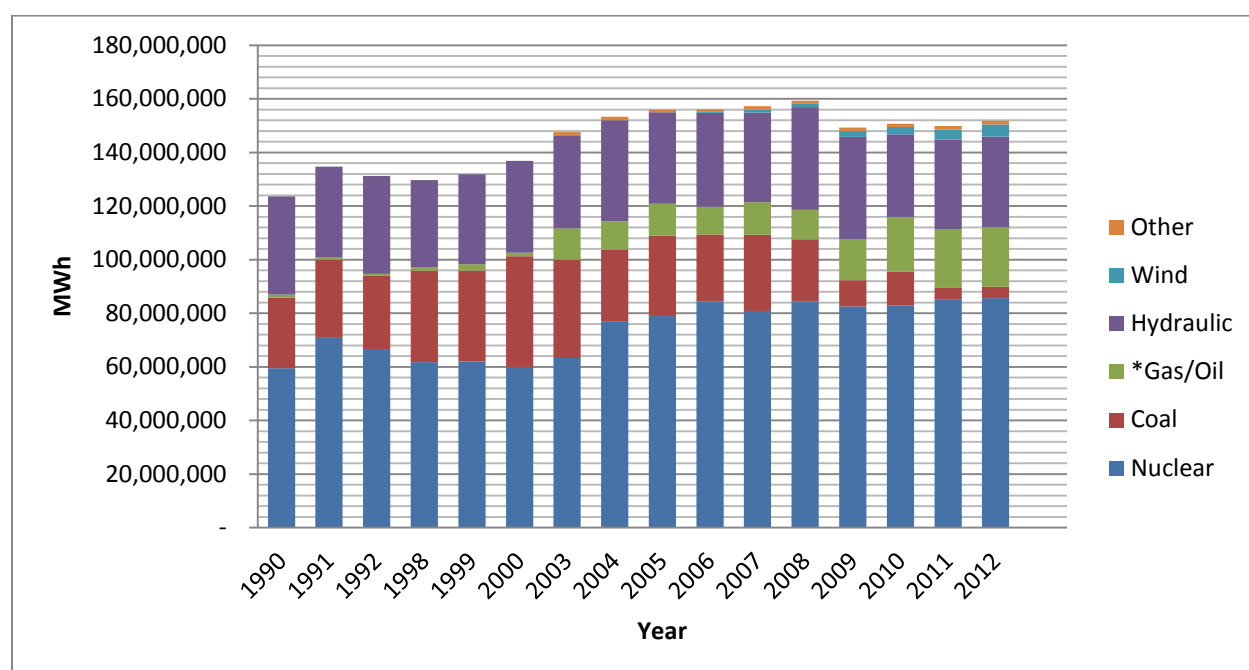
²²¹ Ontario Ministry of Energy, 2013a.

7.2 Supply Mix Changes

Ontario's supply mix was historically dominated by nuclear, coal-fired and hydroelectric generation. While nuclear and hydroelectric still play a prominent role in Ontario's supply mix, coal-fired generation has nearly been phased out completely.

Figure 15, below, shows Ontario's generated output, by generation source, for the 1990 to 2012 period.^{222 223}

Figure 15 - Ontario Generated Output by Source (1990-2012)²²⁴



The main observations that can be made regarding the changes to Ontario's generated output are as follows:

²²² Note that there is no information available for 1993-1997 and 2001.

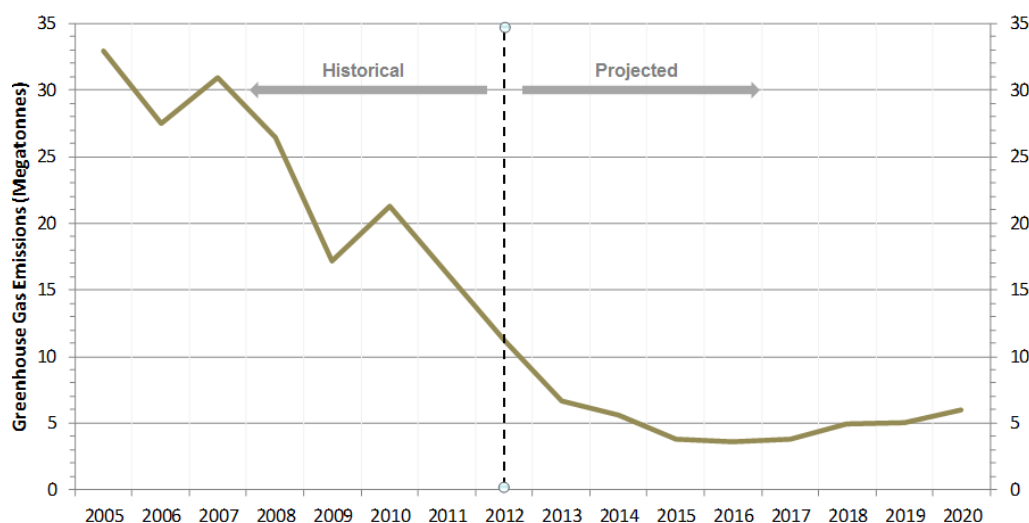
²²³ Also note that prior to 2002, the gas / oil category was entirely oil. Post 2003, the gas / oil category is almost entirely natural gas. In addition, the "other" category is comprised of renewable generation sources.

²²⁴ Derived from Ontario Hydro, Statistical Handbooks, 1990-1992, Independent Electricity System Operator, 2010b, and Independent Electricity System Operator, 2013c.

- From 1990-1998, the mix of generation output remains relatively consistent. However, there is some fluctuation between nuclear and coal based output, which was largely a function of the amount of nuclear capacity that was offline for maintenance.
- Beginning in 2004, the contribution of coal to the supply mix begins to diminish with nuclear and natural gas making larger contributions.
- Beginning in 2006, new renewable generation starts contributing to Ontario's generated output. Electricity output from renewable generation grew moderately through 2012. This trend is expected to accelerate in the future.
- By 2012, coal makes an extremely small contribution to the overall generated output (2.8%) with natural gas-fired generation producing a significant amount of Ontario's total generated output (14%).

An outcome of the shift in Ontario's supply mix and electricity conservation is that the total greenhouse gas emissions associated with electricity generation in Ontario has declined since 2005. Figure 16 highlights the greenhouse gas emissions associated with electricity generation in Ontario.

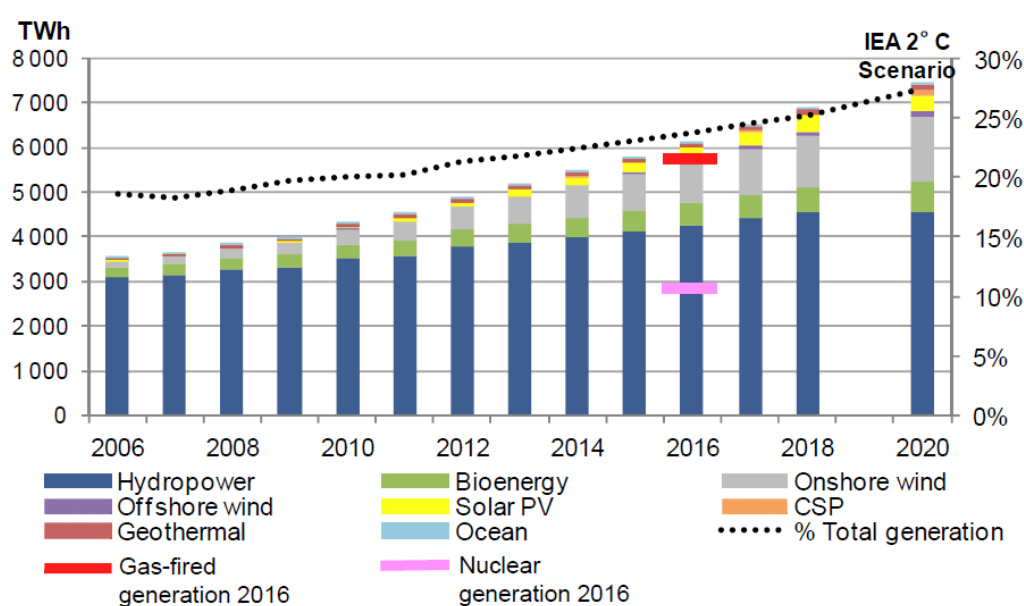
Figure 16 - Electricity Generation - Total Greenhouse Gas Emissions (2005-2020)²²⁵



²²⁵ Ontario Power Authority, 2012: 9.

Changes to Ontario's supply mix are consistent with a global trend over recent years to move towards more environmentally-friendly electricity supply industries that rely on cleaner generation technologies. Globally, there has been significant investment in renewable generation in recent years and renewable energy development is expected to accelerate in the future. Table 17 sets out the increase in global renewable based electricity production (disaggregated by technology type) over the 2006-2013 time period and a forecast of renewable energy production until 2020.

Figure 17 - Global Renewable Electricity Production by Technology (2006-2020)²²⁶



Overall, due to the post-restructuring policy direction taken by government to phase out coal and add renewables to the supply mix, Ontario's generated supply has grown progressively more environmentally friendly over the last decade. In 1992, approximately 20% of generated electricity in Ontario was sourced from coal-fired generation stations. By 2012, only 2.8% of Ontario's generated output was sourced from coal-fired plants and nearly 4% of Ontario's electricity was sourced from renewable sources of supply. The greater reliance on renewable generation in Ontario, and an overall "greening" of the supply mix, follows the trend that is being experienced across the world. As such, the provincial government's policies designed to make Ontario's

²²⁶ International Energy Agency, 2013: 2.

electricity sector more environmentally-friendly would have likely been implemented irrespective of the sector restructuring.

As will be discussed later, the shift that has occurred in Ontario's supply mix, while beneficial to the environment, has applied pressure on commodity prices.

7.3 Impact of Conservation Programs and the Decline in Electricity Average Use

Over the post-restructuring period, a number of programs have been created which seek to reduce electricity consumption (and peak demand) in the province. Numerous conservation and demand management ("CDM") programs were administered by various levels of government, the OPA, and the LDCs during the post-restructuring period. In addition, private companies and individuals have also been investing directly in energy conservation over the post-restructuring period.

In 2004, the Minister of Energy granted approval for all electricity distributors in Ontario to apply for an increase in their 2005 rates contingent upon their investment of an equivalent amount in CDM. This is known as "Third-Tranche CDM". These conservation activities occurred over the period 2005 – 2008. Overall, 85 distributors spent \$163 million on Third-Tranche CDM programs yielding approximately 1,350 GWh of energy savings and 220 MW of peak demand savings.²²⁷

The *Green Energy Act* included a provision²²⁸ that allowed the Minister of Energy to issue directives which could require the OEB to specify, as a condition of licence, conservation and demand management targets ("CDM Targets") for electricity distributors. The Minister of Energy exercised that power in 2010. Together, the CDM targets established for all the LDCs totaled 6,000 GWh of energy and 1,330 MW of demand savings. The reductions were to be achieved through the delivery of CDM

²²⁷ Ontario Energy Board, 2009b: 1-2.

²²⁸ Through an amendment to section 27.2 of the *Ontario Energy Board Act*.

Programs over a four-year period beginning January 1, 2011 and ending December 31, 2014.²²⁹

A total of \$231 million was spent on conservation programs in 2011 and 2012. This resulted in 1,110 GWh of energy savings and 465 MW of peak demand savings on a net basis for those years.^{230 231}

It is important to note that electricity distributors may be paid a performance incentive associated with their CDM activities.^{232 233} LDCs are also made whole for their lost revenues due to the savings generated from their own conservation activities through the Lost Revenue Adjustment Mechanism.²³⁴ The spending amounts noted earlier only reflect direct costs of the conservation programs and do not include the Lost Revenue Adjustment Mechanism and incentive costs that are paid for by ratepayers.

The direct spending and results of post-restructuring period conservation programs offered by LDCs has been described. The OPA, municipal government, and private companies / individuals also invested in CDM during the post-restructuring period. The Ministry of Energy, in a recent report setting out its future plan for conservation in the province, estimated that between 2006 and 2011, a total of \$2 billion was invested in CDM.²³⁵ The report estimated that for every \$1 spent on conservation, Ontario has

²²⁹ Ontario Energy Board, 2012d: 2.

²³⁰ Note that the energy savings arising from the conservation programs are expected to persist for some time. If a conservation program manages to reduce consumption by 100 kWh a year, that same 100 kWh is expected to be saved in the next year. The savings cited reflect only the net savings from the programs with no assumptions made with regards to the persistence of the savings.

²³¹ Ontario Energy Board, 2012d: 5-6, 8, and Ontario Energy Board, 2013b: 6 and 8.

²³² The Board may approve performance incentive payments based on a distributor's verified results in meeting its CDM Targets. The CDM Code states that "a distributor may accrue a performance incentive once it meets 80% of each of its CDM Targets."

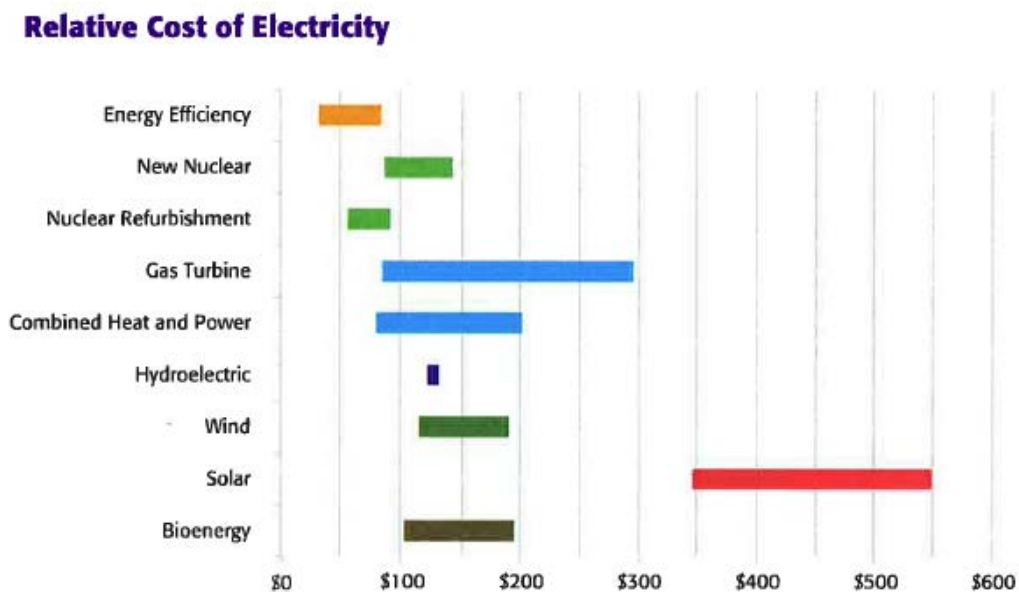
²³³ Ontario Energy Board, 2010b: 14-15.

²³⁴ Ontario Energy Board, 2012e: 11.

²³⁵ Note that the government's report does not describe how the \$2 billion investment amount was calculated. However, the amount likely reflects a high-level estimate of all government, LDC, and private investment in conservation.

avoided \$2 in costs to the electricity system.²³⁶ Figure 18 sets out the cost in \$ / megawatt hours (“MWh”) of different electricity resources (including conservation).

Figure 18 - Relative Cost of Electricity Resources (2013)²³⁷



The table highlights that conservation investment is significantly less expensive than building new generation capacity. The government has made it clear that it will continue to invest heavily in conservation as it is the cleanest and least costly energy resource.²³⁸

As noted above, the LDC-led conservation programs alone resulted in energy savings, on a net basis (i.e. no assumptions regarding persistence have made), of over 2,300 GWhs and 685 MW of peak demand savings over the 2005-2012 period. These are significant savings that have provided environmental benefits to the province through reduced emissions associated with electricity generation.

The investment in conservation is partially responsible for the decline in the average use of electricity that Ontario has experienced from 1990 to 2012.

²³⁶ Ontario Ministry of Energy, 2013c: 1-2.

²³⁷ Ibid: 2.

²³⁸ Ibid: 2-3.

For residential customers only, average electricity use associated with the pre-restructuring period (1990-1997) was 882 kWh / month. The average electricity use associated with the post-restructuring period (2006-2012) was 782 kWh / month. This reflects a decline of 100 kWh / month (or approximately 11%). From 2006-2012, average use declined from 795 kWh / month to 755 kWh / month. This reflects a reduction in average use of 40 kWh / month (or approximately 5%).²³⁹

It is likely that conservation programs and general residential construction practices (i.e. adoption of higher energy efficiency standards) account for the majority of the reduction in residential average use as between the pre-restructuring and post-restructuring periods.

When all utility customer classes are taken into account, the average electricity use associated with the pre-restructuring period (1990-1997) was 2,635 kWh / month. The average use associated with the post-restructuring period (2006-2012) was 2,231 kWh / month. This reflects a decline of 404 kWh / month (or approximately 15%). From 2006-2012, average use declined from 2,306 kWh / month to 2,231 kWh / month. This reflects a reduction in average use of 75 kWh / month (or approximately 3%).²⁴⁰

The decline in utility wide average use (i.e. across all customer classes) can be partly explained by conservation programs and general construction practices. However, economic factors also play a large role in the utility wide average use since the dataset includes commercial and industrial customers. When large volume customers (i.e. large commercial and industrial businesses) reduce their electricity consumption or close down altogether due to market factors (for example, a recession), the utility wide average use also declines because total consumption reduces by a relatively larger proportion than the reduction in the number of customers (in other words, the loss of only one large volume customer can account for a significant reduction in consumption and therefore cause a decline in the total average use of all customers). In short, the

²³⁹ Derived from Ontario Hydro, Statistical Handbooks, 1990-1997 and Ontario Energy Board, Yearbook of Electricity Distributors, 2006-2012.

²⁴⁰ Ibid.

decline of the manufacturing sector in Ontario is partially responsible for reduced utility wide average use.

The impact of conservation is more prominent in the residential average use information because market factors play a less prominent role in that dataset in contrast to the utility wide average use information. For both the residential average use and the utility wide average use it is not possible to definitively determine the extent to which conservation programs are reducing average use since there are other factors that also impact consumption. However, conservation programs are having some unquantifiable impact on reducing the average electricity use of consumers as demonstrated by the aggregate electricity savings arising from the conservation programs led by the LDCs.

Overall, conservation efforts are resulting in significant energy and demand savings in the province in a cost-effective manner. Conservation investment results in the deferment and / or avoidance of capital spending on generation capacity development. Reduced electricity consumption also provides environmental benefits in terms of reduced emissions associated with electricity generation.

7.4 Smart Grid Implementation, Time-of-Use Pricing, and the Impact on Peak Demand

As noted previously, one of the goals of the *Green Energy Act* was to promote the development of a smart grid in Ontario.²⁴¹ Among other goals, a main purpose of a smart grid is to facilitate the adoption of a ToU-based pricing mechanism through the deployment of smart meters. ToU pricing is designed to reflect the costs associated with electricity production as it changes throughout the day. During off-peak times, demand is lowest and less costly sources of generation (i.e. baseload nuclear and hydroelectric) are used to meet the demand. In contrast, on-peak hours reflect when demand is highest and more expensive (and higher emission) sources of electricity (i.e. gas-fired peaking generation) are called upon to meet the incremental demand. The purpose of ToU pricing is to spread consumption from capacity constrained times more evenly

²⁴¹ Ontario Ministry of Energy, 2013a.

throughout the day in order to avoid generation and transmission capacity investments.²⁴²

The government aggressively pursued the implementation of smart meters in Ontario. By August 2012, nearly 100% of eligible customers in Ontario had smart meters installed and approximately 91% of eligible customers were subject to ToU pricing.²⁴³

The most recent data available regarding the spending associated with the installation of smart meters was found in the Auditor General's 2014 Annual Report.²⁴⁴ The Report was released in December 2014 and includes all smart grid investment up to the end of 2014.

The following table sets out both the direct and indirect smart grid-related costs disaggregated by entity and spending category.

²⁴² Ontario Ministry of Energy, 2014.

²⁴³ Ontario Energy Board, 2012c: 4.

²⁴⁴ Auditor General of Ontario, 2014: 362-406.

Figure 19 – Smart Grid Spending by Entity and Cost Category (up to 2014)²⁴⁵

Smart Grid Spending by Entity and Cost Category		
Entity	Cost Category	Approximate Cost (millions)
Ministry of Energy	Consultant fees - development of an implementation strategy for smart grid	\$0.16
	Consultant and legal fees - initial implementation stage of smart grid	\$0.4
	Communication Costs – raising public awareness of smart grid	\$0.64
Ontario Energy Board	Developing smart grid implementation plan for Ministry of Energy	\$0.42
	Consultant fees – ToU rate setting	\$0.41
	Consultant fees – impact analysis of ToU rates	\$0.18
Independent Electricity System Operator	Developing, implementing and operating the Smart Metering Entity and Data Centre	\$160
Local Distribution Companies	Implementing smart meters and other smart grid related costs	\$1,400
	Stranded costs related to analog meters	\$400
Total		\$1,962

The above table shows that almost \$2 billion was spent on implementing a smart grid in Ontario (as of 2014). The majority of the costs incurred are associated with the installation of smart meters (and related smart grid enabling improvements) by the LDCs and the stranding of existing analog meters.

It is important to note that not all of the \$2 billion in smart grid-related spending are included in the electricity prices discussed later in the paper as some of these costs were incurred after 2012. For example, regarding the IESO costs associated with the development and operation of the Smart Metering Entity, approximately \$100 million

²⁴⁵ Ibid: 376.

was spent on the Smart Meter Entity at the end of 2012 (in contrast to the \$160 million set out in the table).²⁴⁶

In regard to the costs associated with the stranding of analog meters, some portion of these costs (\$400 million) could have been avoided had the government allowed for a longer timeframe for smart grid implementation. Due to the aggressive implementation targets set by government, LDCs were required to replace customers' existing analog meters well before the end of their useful lives. The 2014 Auditor General's Annual Report noted that, on average, the analog meters that were replaced could have been used for another 5 to 16 years.²⁴⁷

The OEB, in 2013, retained Navigant Consulting Limited ("Navigant") to analyze the impact of ToU prices in Ontario. A principal goal of Navigant's study was to estimate the historical impact that ToU rates had on the consumption patterns of a sample of customers.^{248 249} In order to do this, Navigant utilized two independent econometric models noting that "if two wholly independent approaches, with only the underlying data in common, deliver a similar result, we may have a very high level of confidence in the result."²⁵⁰

The primary conclusions of Navigant's report are as follows:

- Residential consumers reduced their on-peak consumption and increased their off-peak consumption in response to ToU prices in the summer pricing period. On

²⁴⁶ Ontario Energy Board, 2013c: Appendix A, 2.

²⁴⁷ Auditor General of Ontario, 2014: 390.

²⁴⁸ Navigant Consulting Limited, 2013: i.

²⁴⁹ The underlying data used in Navigant's study was based on a database of hourly load data from 16 LDCs developed by the OEB. The database included hourly load data for about 200 RPP customers per LDC and consisted of information for both residential and small general service customers (less than 50 kW demand). The information included in the database included at least 1 year of pre-ToU information and 1 year of post-ToU pricing information. Navigant added another 13,500 customers to the database using information that it received from Toronto Hydro, Hydro Ottawa, Hydro One and Newmarket-Tay Hydro.

²⁵⁰ Ibid.

average, residential consumers reduced summer on-peak consumption by 3.3% and mid-peak consumption by an average 2.2%. Off-peak weekday consumption increased, on average, by 1.2% and off-peak weekend consumption increased, on average by 1.9%.

- In the winter pricing period, residential demand decreased at all times of day, every day of the week. On average, mid-peak consumption reduced by 3.9%, on-peak consumption reduced by 3.4%, off-peak weekday consumption reduced by 2.5% and off-peak weekend consumption reduced by 1.2%. Some of the load reduction, over the winter period, could be attributed to conservation in response to ToU rates.
- Total residential on-peak demand was estimated to be reduced by 179 MW in the summer and 204 MW in the winter due to ToU pricing.
- The findings for general service customers were largely inconclusive.²⁵¹

Overall, Navigant's report highlights that the peak demand savings associated with ToU pricing have been quite modest. The reason that ToU pricing has not caused a more significant reduction in peak demand could be that the ToU rates have not been designed effectively.

Firstly, the difference between the on-peak and off-peak ToU price has narrowed significantly since ToU prices were first offered. In 2006, when ToU rates were first offered, the on-peak ToU rate was almost 300% higher than the off-peak rate. By 2014, the on-peak rate was only 180% larger than the off-peak rate. This narrowing of the price differential for electricity between on-peak and off-peak times reduces the pricing incentive for customers to shift their consumption away from periods of high demand, which could be partially responsible for the only modest change in consumption patterns.²⁵²

²⁵¹ Ontario Energy Board, 2013d: 2.

²⁵² Auditor General of Ontario, 2014: 381.

Secondly, the pricing blocks for the different times of the day (on-peak, mid-peak, and off-peak) do not accurately reflect actual patterns of electricity consumption. For example, the off-peak period, on weekdays, begins at 7 pm, which, on an actual basis, is a period of high demand. Consumers are paying off-peak prices after 7 pm and are therefore not incentivized to shift consumption at that time of the day even though it is a period of high demand in Ontario.²⁵³

In the future, if the above noted ToU rate design issues are addressed, it is possible that more substantive demand shifting could occur. This would provide more value to consumers for their investment in smart grid infrastructure.

Overall, a very significant amount has been invested in smart grid implementation (almost \$2 billion by 2014). Certain smart-grid related costs (i.e. stranded meter costs) could have been avoided if the government had been less aggressive with its timelines for implementation.

The investment appears, at this early stage, to result in a modest reduction in peak demand. However, given the \$2 billion investment in smart grid infrastructure more substantial peak demand reductions will need to be seen in the future for the investment to have provided strong value for consumers.

7.5 Conclusion

As I discuss in greater detail later in this paper, significant costs were incurred in shifting Ontario's supply mix to greener sources of electricity, implementing conservation programs over the years, and developing a smart grid. This significant investment has resulted in a more environmentally-friendly electricity supply industry in Ontario and has greatly reduced greenhouse gas emissions associated with electricity generation. The province generates its electricity from cleaner energy sources, average electricity use has declined and consumption has started shifting, albeit modestly, from on-peak to off-peak times.

²⁵³ Ibid: 381-382.

The changes to Ontario's generation supply mix, investment in conservation programs, and investment in the development of a smart grid largely arose out of post-restructuring policy decisions of government. The government's policy framework to promote environmental sustainability of Ontario's electricity sector is not directly tied to the restructuring. It is likely that the government would still have undertaken these policies (or at least, similar policies), even if the electricity sector was never restructured.

8. Electricity Pricing Analysis

8.1 Introduction

In this section, I will analyze the “all-in” electricity prices and the distribution prices from 1983 to 2012. As described in Chapter 5 on methodology, two comparative analysis frameworks for understanding the changes in electricity prices before and after restructuring are used.

The first comparative analysis framework uses the period from 1983-1997 to reflect the pre-restructuring era and 1998-2012 to reflect the post-restructuring era. This timeframe reflects the 15 years immediately before and after restructuring.

The second comparative analysis framework uses the period from 1991-1997 to reflect the pre-restructuring period and 2006-2012 to reflect the post-restructuring period. This timeframe reflects the 7 years before restructuring and a 7 year period after restructuring (where actual electricity pricing data is available).

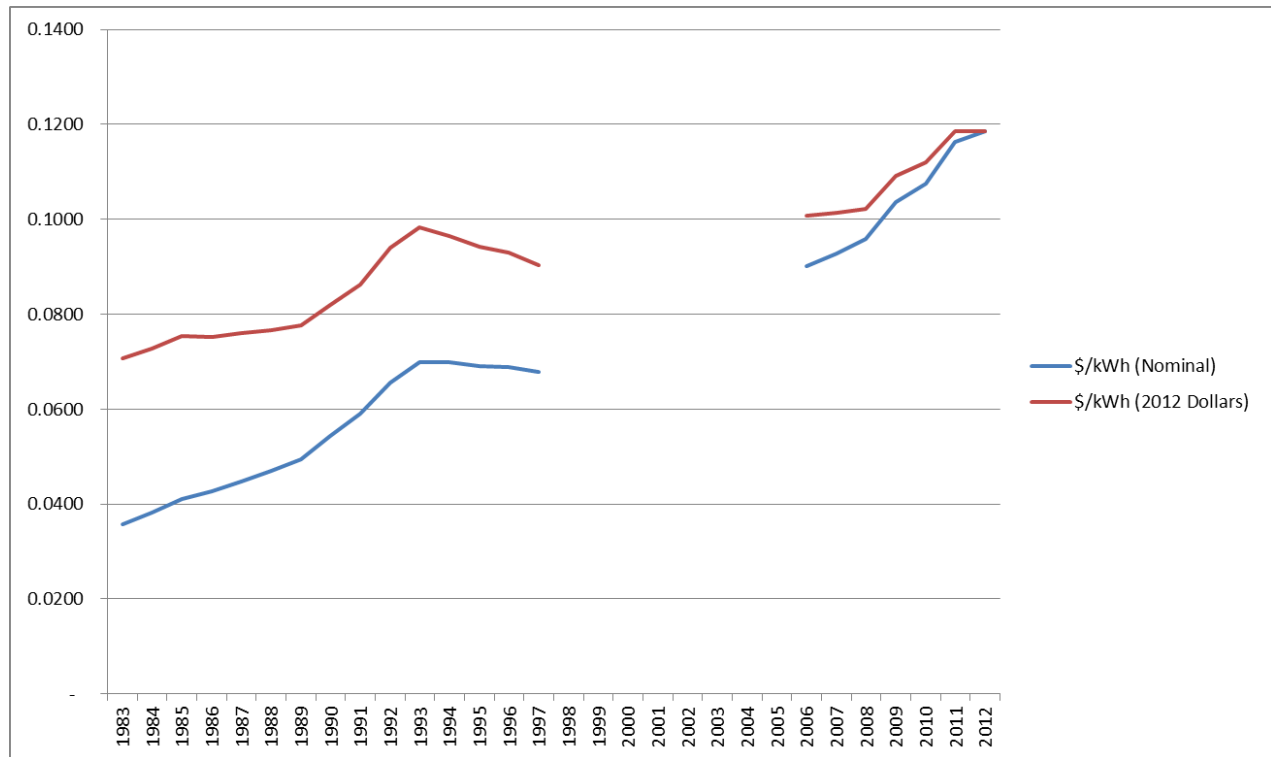
After the pricing data has been set out, I will provide the results of the statistical analysis.

8.2 “All-in” Electricity Price Analysis

Figure 20 sets out the “all-in” electricity price over the period 1983 to 2012 on both a nominal and inflation-adjusted basis. It shows that the “all-in” price for electricity (which includes commodity, transmission, distribution and regulatory charges) rose from 1983 until about 1993 when prices start to fall until 1997 (when the pre-restructuring dataset ends). This decline in electricity prices, seen in the graph, is due to the price freeze on Ontario Hydro’s rates which was in place from 1993 to 1998. From 2006, when the post-

restructuring dataset begins, until 2012 prices rose more rapidly than in the pre-restructuring period on a real basis.²⁵⁴

Figure 20 - "All-in" Electricity Price (1983-2012)²⁵⁵



Using the first comparative analysis framework, Figure 21 highlights the key changes to the “all-in” electricity price.

²⁵⁴ Note that the following price restrictions are implicitly captured in the pricing information from 1998-2005:

- 1998- May 2002 – Transition period pricing limitations on OPG’s generated output.
- May 2002-March 2005 - Restrictions were put in place on the price paid to OPG for electricity. This reflects a partial commodity freeze (prices were effectively capped for a portion of generated output); and
- May 2002 (retroactive adjustment)-2004 – A price cap was put in place on the HOEP price (4.3 cents / kWh for low volume customers) and transmission and distribution rates were also restricted. This effectively resulted in a full freeze on electricity prices during the noted period.

²⁵⁵ Derived from Ontario Hydro Statistical Handbooks, 1983-1997, Ontario Hydro Annual Reports, 1990-1999, Independent Electricity System Operator 18-month Outlook Tables, May 2013 & February 2014, Independent Electricity System Operator Monthly Market Reports, 2006-2012, and Ontario Energy Board, Yearbook of Electricity Distributors, 2006-2012.

Figure 21 - Changes to “All-in” Electricity Prices (1983-2012)²⁵⁶

"All-in" Electricity Prices (1983-1997 & 1998-2012) – Key Changes	
Nominal	
Nominal 1983 - 1997 Average Annual Increase	4.78%
Nominal 1998 - 2012 Average Annual Increase	4.10%
Nominal 1983 - 2012 Average Annual Increase	4.41%
Nominal 1983 - 1997 Total Increase over Period	90.42%
Nominal 1998 - 2012 Total Increase over Period	68.51%
Nominal 1983 - 2012 Total Increase over Period	232.64%
Real (GDP IPI FDD)	
Real 1983 - 1997 Average Annual Increase	1.77%
Real 1998 - 2012 Average Annual Increase	1.92%
Real 1983 - 2012 Average Annual Increase	1.83%
Real 1983 - 1997 Total Increase over Period	27.95%
Real 1998 - 2012 Total Increase over Period	29.51%
Real 1983 - 2012 Total Increase over Period	67.84%

During the pre-restructuring period relevant to this analysis framework (1983-1997), electricity prices increased, on average, by 4.78% each year on a nominal basis. While, in the post-restructuring period (1998-2012) electricity prices increased, on average, by 4.10% on a nominal basis. On a real basis, electricity prices increased, on average, by 1.77% each year in the pre-restructuring period. While, in the post-restructuring period electricity prices increased, on average, by 1.92%. In aggregate, on a nominal basis, electricity prices increased by over 230% from 1983 to 2012. On an inflation-adjusted basis electricity prices increased by about 68% during the 1983-2012 timeframe.

Using the second comparative analysis framework, Figure 22 sets out the key changes to the “all-in” electricity price.

²⁵⁶ Ibid.

Figure 22 - Changes to “All-in” Electricity Prices (1991-2012)²⁵⁷

"All-in" Electricity Prices (1991-1997 & 2006-2012) – Key Changes	
Nominal	
Nominal 1991 - 1997 Average Annual Increase	2.44%
Nominal 2006 - 2012 Average Annual Increase	4.72%
Nominal 1991 - 2012 Average Annual Increase	3.60%
Nominal 1991 - 1997 Total Increase over Period	14.83%
Nominal 2006 – 2012 Total Increase over Period	31.65%
Nominal 1991 - 2012 Total Increase over Period	100.60%
Real (GDP IPI FDD)	
Real 1991 - 1997 Average Annual Increase	0.87%
Real 2006 - 2012 Average Annual Increase	2.80%
Real 1991 - 2012 Average Annual Increase	1.59%
Real 1991 - 1997 Total Increase over Period	4.75%
Real 2006 - 2012 Total Increase over Period	17.78%
Real 1991 - 2012 Total Increase over Period	37.41%

During the pre-restructuring period relevant to this analysis framework (1991-1997), electricity prices increased, on average, by 2.44% each year on a nominal basis. While, in the post-restructuring period (2006-2012) electricity prices increased, on average, by 4.72% on a nominal basis. On a real basis, electricity prices increased, on average, by 0.87% each year in the pre-restructuring period. While, in the post-restructuring period electricity prices increased, on average, by 2.8%. In aggregate, on a nominal basis, electricity prices increased by over 100% from 1991 to 2012. On an inflation-adjusted basis electricity prices increased by about 37.4% from 1991-2012. This is comprised of an approximate 5% increase from 1991-1997 and an approximate 17.8% increase from 2006-2012.

Overall, during the 2006-2012 period (where actual pricing information is available), the “all-in” price for electricity was increasing quite rapidly (nominal price increases of 4.72% and real price increases of 2.8%). The analysis reveals that under both comparative analysis frameworks, the “all-in” electricity prices increased more rapidly in

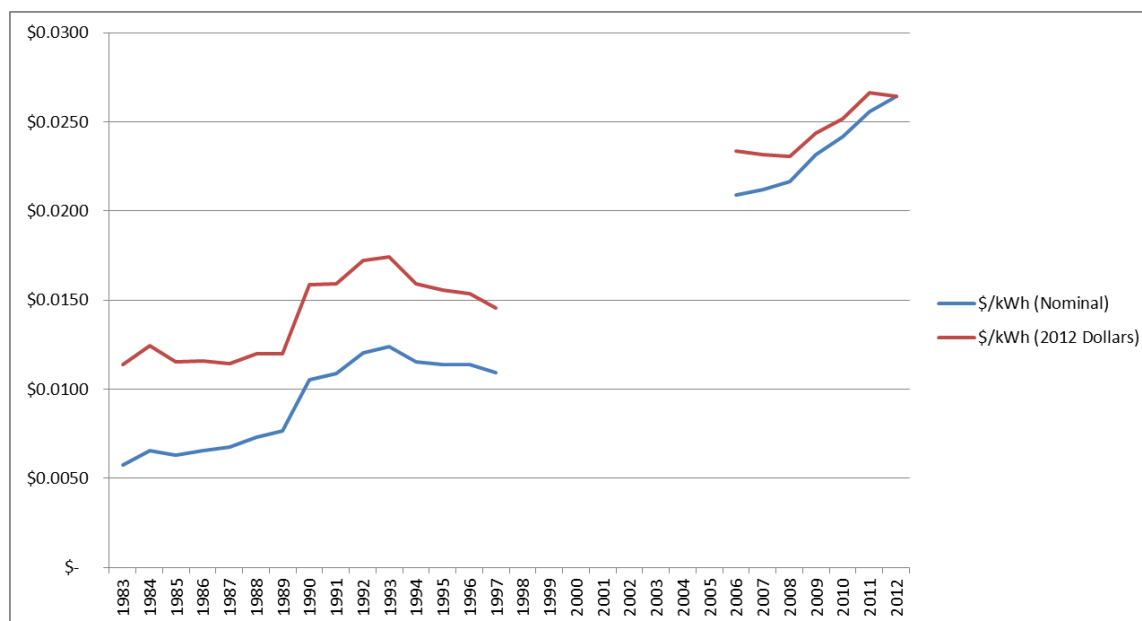
²⁵⁷ Ibid.

the post-restructuring period on a real basis. In the second analysis framework, electricity prices also increased more rapidly on a nominal basis. The reasons for the “all-in” electricity price increasing more substantially in the post-restructuring period is discussed later in this paper.

8.3 Distribution Price Analysis

Figure 23 shows distribution prices over the period 1983 to 2012 on both a nominal and inflation-adjusted basis. Distribution prices rose from 1983 until about 1993 then prices start to fall until 1997 when the pre-restructuring dataset ends. This decline in electricity prices, seen in the graph, is due to the price freeze on Ontario Hydro’s rates (including MEU distribution rates) which was in place from 1993 to 1998. From 2006, when the post-restructuring dataset begins, until 2012 distribution rates rose more rapidly than in the pre-restructuring period.²⁵⁸

Figure 23 - Distribution Price (1983-2012)²⁵⁹



²⁵⁸ Note that the following price restrictions are implicitly captured in the pricing information from 2002-2004: May 2002 (retroactive adjustment)-2004 – Distribution rates were restricted.

²⁵⁹ Derived from Ontario Hydro Statistical Handbooks, 1983-1997 and Ontario Energy Board, Yearbook of Electricity Distributors, 2006-2012.

Using the first comparative analysis framework, Figure 24 demonstrates the key changes to the distribution price.

Figure 24 - Changes to Distribution Prices (1983-2012)²⁶⁰

Distribution Prices (1983-1997 & 1998-2012) – Key Changes	
Nominal	
Nominal 1983 - 1997 Average Annual Increase	5.50%
Nominal 1998 - 2012 Average Annual Increase	7.51%
Nominal 1983 - 2012 Average Annual Increase	6.47%
Nominal 1983 - 1997 Total Increase over Period	89.85%
Nominal 1998 - 2012 Total Increase over Period	120.18%
Nominal 1983- 2012 Total Increase over Period	359.27%
Real (GDP IPI FDD)	
Real 1983 - 1997 Average Annual Increase	1.64%
Real 1998 - 2012 Average Annual Increase	4.75%
Real 1983 - 2012 Average Annual Increase	3.38%
Real 1983 - 1997 Total Increase over Period	27.56%
Real 1998 - 2012 Total Increase over Period	70.46%
Real 1983 - 2012 Total Increase over Period	131.73%

During the pre-restructuring period relevant to this analysis framework (1983-1997), distribution prices increased, on average, by 5.5% each year on a nominal basis. While, in the post-restructuring period (1998-2012) electricity prices increased, on average, by 7.51% on a nominal basis. On a real basis, distribution prices increased, on average, by 1.64% each year in the pre-restructuring period. While, in the post-restructuring period electricity prices increased, on average, by 4.75%. In aggregate, on a nominal basis, electricity prices increased by 359% from 1983 to 2012. On an inflation-adjusted basis electricity prices increased by about 132% during the 1983-2012 timeframe.

Using the second comparative analysis framework, Figure 25 highlights the key changes to the “all-in” electricity price.

²⁶⁰ Ibid.

Figure 25 - Changes to Distribution Prices (1991-2012)²⁶¹

Distribution Prices (1991-1997 & 2006-2012) – Key Changes	
Nominal	
Nominal 1991 - 1997 Average Annual Increase	0.20%
Nominal 2006-2012 Average Annual Increase	4.89%
Nominal 1991 - 2012 Average Annual Increase	5.29%
Nominal 1991 - 1997 Total Increase over Period	0.29%
Nominal 2006-2012 Total Increase over Period	26.54%
Nominal 1991 - 2012 Total Increase over Period	142.61%
Real (GDP IPI FDD)	
Real 1991 - 1997 Average Annual Increase	-1.33%
Real 2006-2012 Average Annual Increase	2.13%
Real 1991 - 2012 Average Annual Increase	2.97%
Real 1991 - 1997 Total Increase over Period	-8.52%
Real 2006-2012 Total Increase over Period	13.22%
Real 1991 - 2012 Total Increase over Period	66.18%

During the pre-restructuring period relevant to this analysis framework (1991-1997), distribution prices increased, on average, by 0.2% each year on a nominal basis. While, in the post-restructuring period (2006-2012) distribution prices increased, on average, by 4.89% on a nominal basis. On a real basis, distribution prices decreased, on average, by 1.33% each year in the pre-restructuring period. While, in the post-restructuring period distribution prices increased, on average, by 2.13%. In aggregate, on a nominal basis, distribution prices increased by about 143% from 1991 to 2012. On an inflation-adjusted basis, distribution prices increased by about 66% from 1991-2012.

Overall, under both comparative analysis frameworks, distribution prices increased more rapidly in the post-restructuring period on both a nominal and real basis. The reason why distribution rates increased more substantially in the post-restructuring period is discussed later in this paper.

²⁶¹ Ibid.

8.4 Statistical Analysis Results

As discussed in Chapter 5, the regression analysis, as set out below, utilized the nominal “all-in” electricity prices for the period 1983-2012.

I generated two sets of dummy variables to analyze the impact that the restructuring had on electricity prices:

- (a) First, I created a restructuring dummy indicator variable to come into effect after 2006. This variable reflects the start of the post-restructuring period (where actual data is available). A restructuring / time interaction variable was also generated. As the restructuring dummy indicator variable is set to come into effect in the post-2006 period, the statistical models used understand the post-restructuring period to have begun in 2006. As such, the restructuring dummy indicator variable is capturing the impact of both the restructuring and post-restructuring changes (as the post-restructuring period actually began in 1998).
- (b) Second, I generated the gap dummy indicator variable to come into effect in 1998 and run until 2006 to reflect the pricing data that is not based on actual electricity prices. A gap / time interaction variable was also generated.

In addition to the dummy indicator variables, time and TDD were also used as independent variables in the regressions performed to analyze the impact that the restructuring had on electricity prices.

An ordinary least squares regression was first used to determine whether the restructuring, and post-restructuring changes, was correlated with electricity prices. The regression was run with price set as the dependent variable and the dummy indicator variables, time and TDD set as the independent variables. The results of the regression are set out in Figure 26 below.

Figure 26 - Ordinary Least Squares Regression Results (Full Model)

Source	SS	df	MS	Number of obs = 30		
Model	.014949635	6	.002491606	F(6, 23) = 397.06		
Residual	.000144327	23	6.2751e-06	Prob > F = 0.0000		
Total	.015093962	29	.000520481	R-squared = 0.9904		
				Adj R-squared = 0.9879		
				Root MSE = .00251		

price	Coef.	Std. Err.	t	P> t	[95% Conf. Interval]	
time	.0027591	.0001504	18.35	0.000	.0024481	.0030702
rstr	-.0670641	.0128977	-5.20	0.000	-.0937449	-.0403832
rstrt	.0022938	.0004975	4.61	0.000	.0012647	.003323
gap	-.0107005	.0087834	-1.22	0.235	-.0288703	.0074692
gapt	.0001058	.0004601	0.23	0.820	-.0008459	.0010576
tdd	-5.23e-06	2.44e-06	-2.14	0.043	-.0000103	-1.80e-07
_cons	.0549626	.0105323	5.22	0.000	.033175	.0767503

The results highlight that the restructuring dummy variables both have a p-value of 0. The conclusion, at this point, is that the restructuring and post-restructuring policy changes, as reflected by the restructuring dummy variables, is significantly correlated with the “all-in” price for electricity. In addition, the TDD variable has a p-value of 0.043, which means, using an ordinary least squares regression, weather is also correlated to the “all-in” electricity price.

After running the regression, I needed to consider whether the time-series of electricity prices exhibited autocorrelation problems. I used the Durbin Watson Test to check for autocorrelation problems. The Durbin Watson Test provided a D-stat of 1.150527. The significance bounds for a dataset with 30 observations and 6 regressors are set at dL = 0.812 and dU = 1.707. Therefore, the results of the Durbin Watson test were inconclusive as the D-stat fell within the upper and lower bands of the test.

Given that the data being analyzed is a time-series of electricity prices it is highly probable that an autocorrelation problem exists. I first used the Prais-Winsten estimator was first utilized to try to overcome the expected autocorrelation problems in the dataset. The results of this regression are set out in Figure 27 below.

Figure 27 - Prais-Winsten Regression Results (Full Model)

Prais-winsten AR(1) regression -- iterated estimates

Source	SS	df	MS	Number of obs =	30
Model	.000966055	6	.000161009	F(6, 23) =	40.15
Residual	.000092225	23	4.0098e-06	Prob > F =	0.0000
Total	.00105828	29	.000036492	R-squared =	0.9129
				Adj R-squared =	0.8901
				Root MSE =	.002

price	Coef.	Std. Err.	t	P> t	[95% Conf. Interval]
time	.0024631	.0002954	8.34	0.000	.0018519 .0030743
rstr	-.059795	.0177744	-3.36	0.003	-.0965642 -.0230259
rstrt	.0023147	.0007146	3.24	0.004	.0008365 .0037929
gap	.0013867	.0123783	0.11	0.912	-.0242199 .0269932
gapt	-.000201	.0007406	-0.27	0.789	-.0017331 .0013311
tdd	-1.47e-06	1.60e-06	-0.92	0.369	-4.77e-06 1.84e-06
_cons	.0405019	.0075254	5.38	0.000	.0249344 .0560693

rho	.757031
-----	---------

Durbin-watson statistic (original)	1.150527
Durbin-watson statistic (transformed)	1.450117

The Prais-Winsten regression highlights that the restructuring, and post-restructuring changes, as reflected by the dummy variables, are correlated to the “all-in” electricity price but weather is not. However, the Durbin-Watson statistic associated with the transformed model still reflects an inconclusive result as to whether there is an autocorrelation problem in the pricing data (as the D-stat of 1.450117 for the transformed model still falls within the upper and lower significance bands). Therefore, the Prais-Winsten estimator was unable to conclusively resolve the potential autocorrelation problem. As the Prais-Winsten deals with serial correlation of type AR(1), it is still possible that higher-order auto-regressive problems exist in the dataset.

The ARIMA model allows more extensive parameters to be set in the model, which can potentially deal with higher-order auto-regressive problems. Therefore, I used the ARIMA model to possibly generate a more relevant regression for the dataset. It is important to note that an ARIMA regression can only be applied to stationary data. In the ARIMA model the following parameters can be set:

- The number of autoregressive terms;
- The number of non-seasonal differences; and
- The number of lagged forecast errors in the prediction equation.

I ran a number of tests on the data, based on the autocorrelation function and the partial autocorrelation functions, to determine the appropriate parameters to set for the ARIMA model. The test results highlighted that the number of autoregressive terms associated with the electricity price data underpinning the regression analysis should be set at 3, the number of non-seasonal differences should be set at 1 (this means that the regression is applied to the difference in electricity prices, year-over-year, as opposed to the actual pricing information²⁶²), and the number of lagged forecast errors in the predication equation should be set at 1. Overall, the test results highlighted that the ARIMA (3,1,1) model best fit the dataset.

The ARIMAX(3,1,1) regression was run on the full model (i.e. all the dummy variables and TDD) with the dependent variable being the year-over-year difference in electricity prices. The results of this regression are set out in Figure 28.

Figure 28 - ARIMAX (3,1,1) Regression Results (Full Model)

ARIMA regression						
Sample: 2 - 30			Number of obs		= 29	
			wald chi2(9)		= 31.98	
Log likelihood = 148.2359			Prob > chi2		= 0.0002	
<hr/>						
D.price		Coef.	OPG Std. Err.	z	P> z	[95% Conf. Interval]
<hr/>						
price	rstr D1.	-.0399768	.0213966	-1.87	0.062	-.0819133 .0019597
	rstrt D1.	.0016833	.0008837	1.90	0.057	-.0000488 .0034154
	gap D1.	.0013521	.0295374	0.05	0.963	-.0565401 .0592444
	gapt D1.	-.0000987	.0019104	-0.05	0.959	-.003843 .0036455
	tdd D1.	-1.04e-06	1.09e-06	-0.96	0.337	-3.17e-06 1.09e-06
	_cons	.002456	.000561	4.38	0.000	.0013566 .0035555
<hr/>						
ARMA						
ar	L1.	.4281887	.3687729	1.16	0.246	-.2945929 1.15097
	L2.	.4764881	.2575299	1.85	0.064	-.0282613 .9812375
	L3.	-.6931938	.2345316	-2.96	0.003	-1.152867 -.2335203
ma	L1.	-.2035967	.554574	-0.37	0.714	-1.290542 .8833484
	/sigma	.0014055	.0002803	5.01	0.000	.0008561 .0019549
<hr/>						

²⁶² Setting the number of non-seasonal differences at 1 ensured that the pricing information was stationary and allowed the ARIMA regression to operate correctly.

The results highlight that the restructuring, and post-restructuring changes, as reflected by the dummy variables, are correlated to the difference in price of electricity (p-values of 0.062 and 0.057 respectively).²⁶³ The coefficient associated with the restructuring interaction variable is positive, which means that the restructuring, and post-restructuring changes, are positively correlated with the increases in electricity prices over time. In addition, the final AR term has a p-value of 0.003, which means that the 3rd AR term is significantly different from zero. This supports the conclusion that the number of autoregressive terms have been properly set at 3. In this ARIMAX regression, none of the other variables seem to be correlated with the difference in price of electricity.

Overall, the results of the ARIMAX regression highlight that the restructuring, and post-restructuring changes in the electricity sector, are positively correlated to the rapid increase in electricity prices that occurred during the post-2006 period.

8.5 Conclusion

When comparing the pre- and post- restructuring periods, it is clear that, on a real basis, the “all-in” electricity price has increased more rapidly in the post-restructuring period under both of the comparative frameworks used in this paper. On a nominal basis, electricity prices increased more rapidly in the post-restructuring period when utilizing the second comparative framework (1991-1997 vs. 2006-2012).

Distribution prices have also increased more rapidly, on both a real and nominal basis, in the post-restructuring period (under both comparative analysis frameworks).

Based on the above analysis, it is fair to conclude that the “all-in” electricity prices and distribution prices have been rising more rapidly in the post-restructuring period when compared to the pre-restructuring period (especially when the analysis focuses on electricity prices during the more recent years – 2006-2012). The regression analysis

²⁶³ Given the small number of observations in the dataset, p-values of less than 0.1 consistent with a 10% significance level are considered significantly correlated to the “all-in” electricity price.

confirms that the restructuring, and other post-restructuring changes, are positively correlated to the sharp rate increases observed in the post-restructuring period.

In the next section, I will discuss the specific changes to Ontario's electricity sector resulting from the restructuring, and other post-restructuring policies, that could be responsible for the rapid increase in electricity prices over the post-restructuring period.

9. Price Drivers and the Impact on Electricity Consumers

9.1 Introduction

In Chapter 8, I established that electricity prices are rising more rapidly in the post-restructuring period on a real basis (under both comparative analysis frameworks) and also on a nominal basis using the second comparative analysis framework (i.e. 1991-1997 vs. 2006-2012). The statistical analysis demonstrates that the restructuring, and post-restructuring changes in the sector, are positively correlated to the rapid increase in electricity prices post-2006.

In this section, I will discuss the specific price drivers which may have caused, or conversely, helped to mitigate the rate increases that occurred over the post-restructuring period. Each price driver that has impacted the price of electricity during the post-restructuring period, is linked to the cause of the price driver (i.e. restructuring-related policies, post-restructuring policies, or other factors not directly related to electricity sector policy decisions). In addition, each price driver is analyzed from the consumer perspective to determine whether it has benefitted ratepayers.

After the restructuring, electricity consumers began to pay for the components of electricity service (commodity, transmission, and distribution) separately. I have categorized the price drivers by component of electricity service.

I will analyze the commodity-related price drivers first. The commodity-related price drivers include: supply mix changes; premiums paid for renewable generation; and higher prices paid for output from legacy and new generators.

Analysis of the transmission-related price drivers (i.e. increased capital and operational costs of Hydro One) will follow.

Third, I will analyze the distribution-related price drivers. The distribution-related price drivers include: returns paid to the LDCs; transition costs incurred at the beginning of the post-restructuring period; increasing operational costs of the LDCs; mergers of the LDCs; smart grid implementation; and renewable generation connection costs.

Finally, I will analyze the price drivers that cannot be assigned exclusively to one of the above components. These “full-sector” price drivers include: IESO operation costs; OPA administrative costs; OEB regulatory costs; conservation and demand management spending; investment catch-up associated with previous price freezes; Ontario Hydro stranded debt repayments; and reductions to the cost of debt financing.

9.2 Commodity-related Price Drivers

9.2.1 Commodity Prices

As shown in Figure 13 in Chapter 6, the total commodity price (Weighted Average Hourly Ontario Electricity Price and global adjustment) has been increasing since 2005. The total commodity price in 2005 was 6.44 cents / kWh. In 2012, the total commodity price was 7.38 cents / kWh. This reflects an increase of almost 15%.

Figures 29 and 30 depict the RPP tiered and RPP ToU prices over the restructuring period.

Figure 29 - Weighted Average RPP - Tiered Price^{264 265}

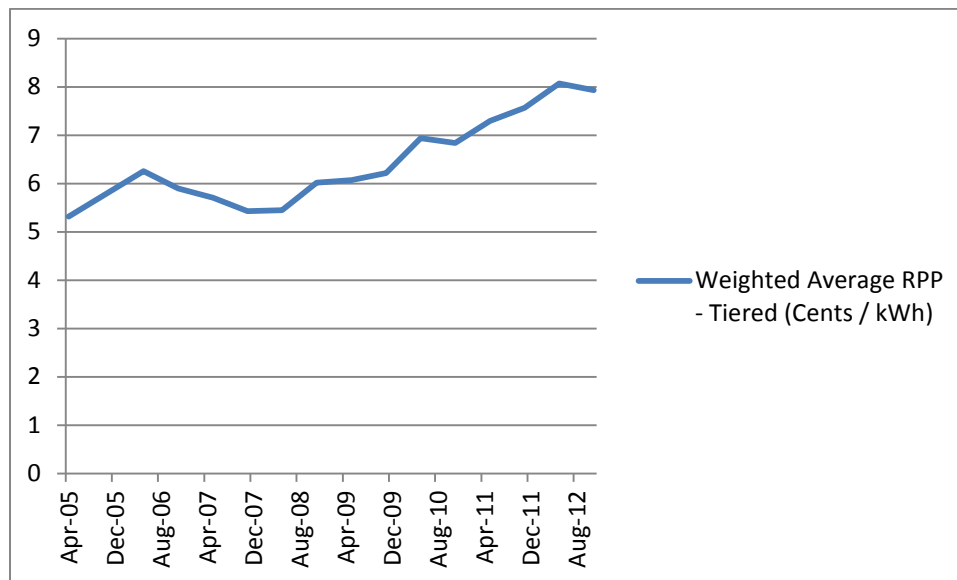
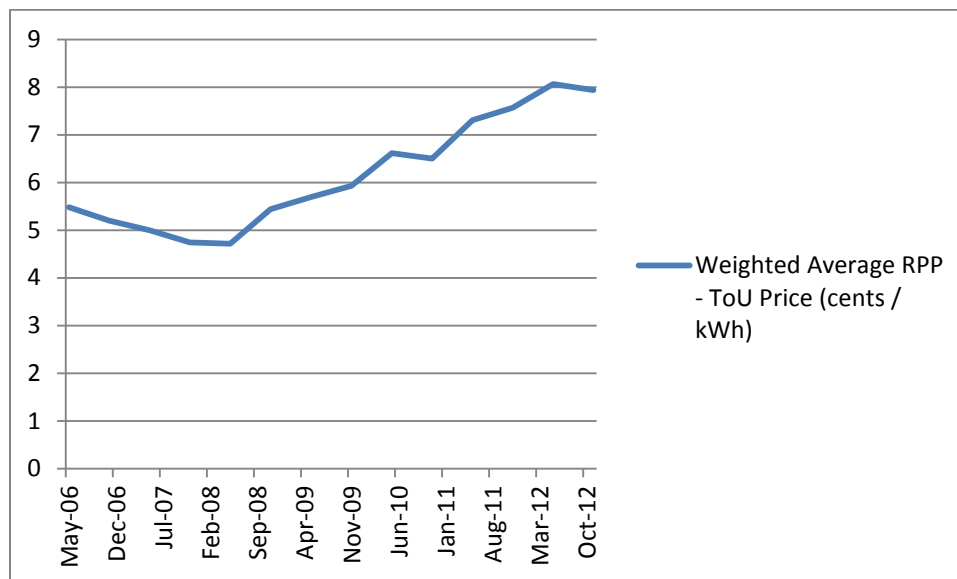


Figure 30 - Weighted Average RPP - ToU Price^{266 267}



²⁶⁴ Derived from Ontario Energy Board, 2014c.

²⁶⁵ The tiered price reflected in the graph is a volume weighted average of the two tiered prices in effect in the relevant period.

²⁶⁶ Derived from Ontario Energy Board, 2014c and Ontario Energy Board, 2013a.

²⁶⁷ The ToU price reflected in the graph is a volume weighted average of the three ToU prices in effect in the relevant period.

Given that the RPP rates (both tiered and ToU) are designed to recover the total cost of the commodity over time, the charts confirm that the price of the electricity commodity has been increasing over the restructuring period. A number of changes in Ontario's electricity sector impacted the commodity price. These changes are discussed below.

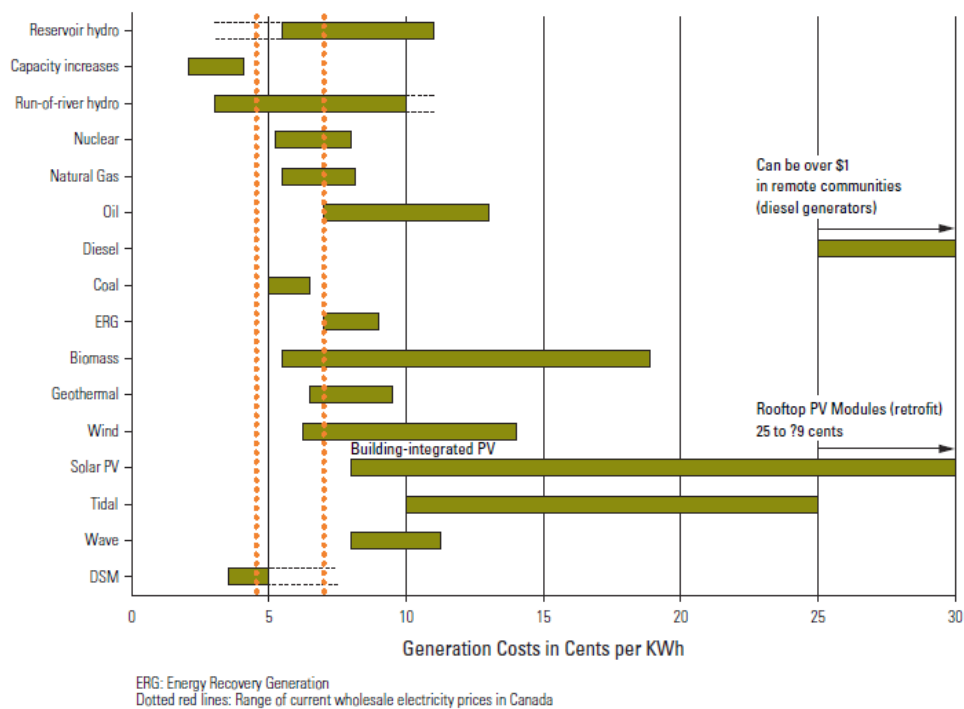
9.2.2 Supply Mix Changes

As discussed previously, over the restructuring period Ontario's supply mix shifted towards more environmentally-friendly sources of electricity generation. Figure 15 in Chapter 6 provides Ontario's generated output by source. It illustrates that coal-fired generation has been largely phased-out in 2012 while the utilization of natural gas-fired generation and renewable generators has increased significantly.

The historical supply mix of Ontario Hydro, which largely consisted of hydro-electric, nuclear and coal generation, provided consumers with relatively low-cost electricity. The new sources of supply which have been utilized to replace coal (largely natural gas, nuclear and renewable generation) have higher generation costs.

Figure 31, below, provides an estimated range of costs associated with generating electricity from a number of different sources. Natural gas-fired generation, nuclear generation and all renewable generation sources are shown to have higher generation costs than coal-fired generation. This means that as coal-fired generation was replaced by these higher cost sources of electricity, the average cost of generation increased in Ontario. As such, commodity rates increased to produce revenues sufficient to cover the increased average cost of generation.

Figure 31 - Generation Costs by Source²⁶⁸



The shift in Ontario's supply mix arose out of post-restructuring policy decisions of the provincial government. Through the June 2006 Minister Directive and the *Green Energy Act*, the government provided policy direction to the OPA regarding its plans to phase-out coal-fired generation and to incorporate renewable generation into Ontario's supply mix.²⁶⁹ This price driver is entirely related to government policy which was implemented during the post-restructuring period.

From a consumer's perspective, the shift in Ontario's generation supply mix has provided environmental benefits (including reduced greenhouse-gas emissions²⁷⁰) because more generated output is now sourced from cleaner energy technologies. However, the trade-off for these environmental benefits is increased commodity prices.

²⁶⁸ Canadian Electricity Association, 2006: 24.

²⁶⁹ Dwight Duncan, 2006: 1-2 and Ontario Ministry of Energy, 2013a.

²⁷⁰ Ontario Power Authority, 2012: 9.

The shift in Ontario's supply mix is partially responsible for the increase in the commodity price paid by Ontario's electricity consumers.

9.2.3 Renewable Generation Procurement Programs

There have been a number of processes for the procurement of renewable generation in Ontario over the years. These procurement processes largely fall into three main types: competitive (i.e. request for proposals), non-competitive (i.e. negotiated prices), and standard offer (i.e. fixed price contracts).

At different times during the mid-2000s, the OPA requested proposals for renewable generation capacity. This occurred under what was known as the Renewable Energy Supply Program. Under the Renewable Energy Supply Program, private generators would submit confidential bids to the OPA and the OPA would select the renewable generation projects that best fit the province's requirements (based on price, location, etc.).

In 2006, the OPA launched the Renewable Energy Standard Offer Program, which allowed prospective renewable generators to attain fixed price and term contracts from the OPA for the supply of electricity produced from renewable energy sources. The purpose of the Renewable Energy Standard Offer Program was to allow small scale renewable generators to more easily access OPA contracts.

In 2009, after the enactment of the *Green Energy Act*, the OPA launched two updated standard offer programs: the Feed-in Tariff Program ("FIT") and the MicroFIT program.²⁷¹ The FIT programs replaced the Renewable Energy Standard Offer Program and offered higher prices for generated output from renewable sources.

Additionally, in 2010, the government privately negotiated a contract with a consortium of companies to develop wind and solar generation in the province.²⁷²

²⁷¹ The FIT program is designed for proposed projects that are larger than 10kW and the MicroFIT program is for projects that are smaller than 10kW.

²⁷² Auditor General of Ontario, 2011: 102-108.

The prices paid for renewable generation by the OPA, under the various programs, are set out in Figure 32.

Figure 32 - Prices Paid for Renewable Generation under OPA Contracts (cents / kWh)²⁷³

	Renewable Energy Supply (RES I, II, III) ¹	Renewable Energy Standard Offer Program (RESOP)	Feed-in Tariff (FIT) and microFIT ²	Korean Consortium ³
	June 2004, June 2005, Aug. 2008	Nov. 2006	Oct. 2009	Jan. 2010
solar (rooftop)		42.00	53.90-80.20	
solar (ground-mounted)		42.00	44.30-64.20	44.30 + 2.60
wind (offshore)		11.00	19.00	
wind (onshore)	9.51	11.00	13.50	13.50 + 0.50
hydroelectric	7.85	11.00	12.20-13.10	
bioenergy	8.23	11.00	10.30-19.50	

1. Weighted averages of all projects.

2. Prices vary depending on project size, with smaller projects typically qualifying for higher prices.

3. Standard FIT prices apply to phase 1 and phase 2 projects, plus additional payment called Economic Development Adder (EDA) as stated in the original Green Energy Investment Agreement (GEIA). Subsequent to our audit fieldwork, the GEIA was amended in July 2011, and the EDA was reduced to 1.43¢/kWh for solar power and 0.27¢/kWh for wind power.

Procurement programs, which include payment premiums, are necessary to facilitate the development of renewable generation capacity in Ontario as renewable sources of supply are generally not competitive on a cost basis with more traditional sources of supply. However, Ontario's FIT program includes some of the highest prices paid for renewable generation in the world. Figure 33 compares the renewable generation payments made under the FIT program to the procurement programs of other jurisdictions. Under the FIT program, the OPA pays renewable generators the highest prices for generated output, from a number of generation sources, when compared against certain jurisdictions in the US, Europe, Asia and Australia. These high premiums have attracted significant interest in developing renewable generation projects in the province.

²⁷³ Ibid: 103.

Figure 33 - Comparison of Ontario FIT Prices to Other Jurisdictions (cents / kWh)²⁷⁴

	Solar (Rooftop)	Solar (Ground-mounted)	Wind (Offshore)	Wind (Onshore)	Hydroelectric	Bioenergy
Canada						
Ontario	53.90-80.20	44.30-64.20	19.00	13.50	12.20-13.10	10.30-19.50
United States						
Michigan	33.54-47.91	33.54-47.91	4.31-15.91	7.67-11.98	9.29-15.33	7.47-14.28
Vermont	28.75	28.75	13.42-19.16	13.42-19.16	—	11.50
Washington ²	14.37-28.75	14.37-28.75	14.37	14.37	—	14.37
Wisconsin	23.96	23.96	6.32-8.82	6.32-8.82	8.82	5.83-14.85
Europe						
Denmark	—	—	10.80	10.80	—	5.40
Germany	29.24-39.80	29.24-39.80	18.01	12.62	4.81-17.55	10.68-16.00
Spain	37.31	37.31	10.14	10.14	10.80	18.09
Asia						
South Korea	63.33	63.33	9.51	9.51	6.52	5.46
Australia						
Australian Capital Territory	46.33	46.33	—	—	—	—
New South Wales	20.27	20.27	—	—	—	—
Queensland	44.60	44.60	—	—	—	—
South Australia	44.60	44.60	—	—	—	—
Victoria	60.82	60.82	—	—	—	—
Western Australia	40.55	40.55	—	—	—	—

1. Prices vary depending on project size, with smaller projects typically qualifying for higher prices. Prices were converted to Canadian currency based on the average exchange rates in April 2011.

2. These base rates are increased if the components are manufactured in Washington.

The Renewable Energy Supply, Renewable Energy Standard Offer and FIT programs have all been very successful at procuring renewable capacity. Under all the above noted procurement frameworks, renewable generation capacity targets were met in extremely short timeframes.²⁷⁵ This leads to the conclusion that reduced payments could have been made for renewable generation under the OPA's procurement frameworks and the associated targets could have still been achieved. As such, renewable generation has increased the average electricity generation cost in Ontario by more than was necessary to attract renewable generation projects. These higher than necessary costs are passed onto consumers in the form of higher commodity rates. The generous incentive payments provided to renewable generators are partially

²⁷⁴ Ibid: 106.

²⁷⁵ Ibid: 103-104.

responsible for the increases in commodity rates experienced in the 2006-2012 period.²⁷⁶

The incremental costs that arose from the renewable generation procurement programs are caused by the post-restructuring policy decisions of government. During the post-restructuring period consumers, while accruing benefits from an environmental perspective, have been paying incremental costs associated with renewable generation procurement frameworks which are arguably too generous to prospective generators.²⁷⁷

9.2.4 Higher Payments for Generated Output from Legacy and New Generators

Prior to the electricity sector restructuring, Ontario Hydro collected, through its rates, revenues sufficient to cover the costs of generation. After the restructuring, total payments to both legacy and new generators were at levels higher than costs (and included a return for the shareholders).

Over the period 1990-1996, output from Ontario Hydro's nuclear generators cost approximately 4.8 cents / kWh on average and output from its hydroelectric facilities cost on average approximately 1.05 cents / kWh.²⁷⁸

²⁷⁶ It is important to note, that consumers, in 2012 (and prior), were not being exposed to the full impact of the high premiums paid for renewable generation in commodity rates as there was not a significant amount of renewable generation capacity online and supplying electricity to the grid at that time. As noted previously, generated output from renewable sources in 2012 comprised approximately 4% of Ontario's total electricity output. In the future, as more of the renewable generation capacity, contracted by the OPA, comes online and begins providing electricity to the grid, the average cost for electricity generation will continue to increase and commodity rates will increase accordingly.

²⁷⁷ Dewees, in 2013, provided a sophisticated quantitative cost-benefit analysis of renewable generation in Ontario. In his paper, the financial cost of renewable generation (under the Ontario's FIT program) is compared with the cost savings associated with the displacement of fossil-fuel generation (coal and natural gas) and the avoided harm related to air pollutants and greenhouse gas emissions.

Dewees concludes that some dispatchable sources of renewable generation (biogas, biomass, etc.) result in savings that meet (or exceed) the FIT prices paid for these types of renewable generation. In contrast, wind and solar generation do not result in savings that justify the prices paid under the FIT program. Overall, Dewees concludes that "Ontario's Feed-in-Tariff program costs more than necessary to achieve its environmental goals."

The above is sourced from: Dewees, 2013.

²⁷⁸ Ontario Hydro, Annual Reports, 1991-1997.

As noted previously, OPG was established after the restructuring to own and operate Ontario Hydro's legacy generation assets (with the exception of those assets which were divested under the Market Power Mitigation Agreement. Payments to OPG related to generated output from its prescribed assets (which are its baseload hydro and nuclear assets) were first set by the government and are now regulated by the OEB. Currently, OPG's payments are set based on a calculation of its revenue requirement which effectively encompasses the entire cost of operating OPG's prescribed assets (including the cost of capital, which has a return on equity component).²⁷⁹

Payments to OPG for generated output from its prescribed assets have increased over the years. From market opening until March 2005, electricity generated from OPG's prescribed assets was paid for at the HOEP (the average wholesale market price over that period was approximately 5.5 cent / kWh).²⁸⁰ OPG, however, was required to make rebates to consumers pursuant to the Market Power Mitigation Agreement²⁸¹ until April 1, 2005 when the government eliminated the rebate.

Beginning in 2005, the government set the payments that would be made to OPG for its generated output from its prescribed assets. The price was set at 4.95 cents / kWh for its nuclear output and 3.3 cents / kWh for its hydroelectric output.²⁸²

Effective April 1, 2008, the OEB reset the payments that would be made to OPG for output from its prescribed assets. The price paid for electricity generated from OPG's nuclear assets was set at approximately 5.5 cents / kWh (including rate riders related to the disposition of deferral / variance account balances) and at 3.7 cents / kWh from its hydroelectric assets.²⁸³

²⁷⁹ Ontario Energy Board, 2008a: 1-7.

²⁸⁰ Independent Electricity System Operator, 2014d.

²⁸¹ As noted previously, under the Market Power Mitigation Agreement, OPG was required to pay a rebate to consumers on 90% of its domestic output when the wholesale market price exceeded 3.8 cent / kWh.

²⁸² Ontario Energy Board, 2008a: 2.

²⁸³ Ontario Energy Board, 2008b: 5.

Effective March 1, 2011, the OEB again reset the payments that would be made to OPG for output from its prescribed assets. The price paid for electricity generated from OPG's nuclear assets and hydroelectric assets was set at approximately 5.6 cents / kWh (including rate riders related to the disposition of deferral / variance account balances) and 3.4 cents / kW respectively.²⁸⁴ The price changes that occurred in 2008 and 2011, as approved by the OEB in its EB-2007-0905 and EB-2010-0008 Decisions, were based on changes to OPG's revenue requirement. OPG's revenue requirement changed due to the underlying costs associated with producing electricity from OPG's prescribed assets (capital expenditures, operation expenses, maintenance expenses, administrative expenses, taxes, and changes to the capital parameters – debt rates and return on equity).

The above illustrates that, after restructuring, the payments made for generated electricity from OPG's prescribed assets were higher than prior to the restructuring. The payments made to OPG in the post-restructuring period also include a return on equity component.²⁸⁵ These higher payments made to OPG for its prescribed assets (as compared to during the pre-restructuring period) are applying pressure on commodity rates.

The assets that were leased / sold by OPG (Bruce nuclear facility and the Mississagi hydroelectric assets), under the Market Power Mitigation Agreement, are also paid higher prices for their generated output than prior to the sector restructuring. Before the electricity sector restructuring, generated output from the Bruce nuclear facilities was paid at a price likely lower than Ontario Hydro's average nuclear generation cost of 4.8 cents / kWh.²⁸⁶ From market opening until 2005, Bruce's generation was paid at the

²⁸⁴ Ontario Energy Board, 2011c: 4-5.

²⁸⁵ It is important to note that the returns earned by OPG are streamed to the Ontario Electricity Financial Corporation to pay down Ontario Hydro's stranded debt. The issue of whether the dividends paid to OPG's shareholder are applying pressure on electricity prices is discussed in sub-section 9.5.7.

²⁸⁶ 4.8 cents / kWh was the average cost of nuclear output for the 1990 – 1995 period. After 1995, the average cost of nuclear generation increased as there were significant future liabilities (which were to be incurred over the 1997-2001 period) associated with the Nuclear Asset Optimization Plan ("NAOP") charged to operations beginning in 1996. The accounting treatment applied to the costs arising from the NAOP distorted the cost of nuclear generation cited in the annual reports for the years 1996 to 1998.

wholesale market price (which during the May 2002 –2005 period averaged approximately 5.5 cents / kWh).²⁸⁷ In 2005, under the Bruce Power Refurbishment Implementation Agreement (which was an agreement between Bruce Power and the OPA), electricity generated was priced at approximately 5.7 cents / kWh from the Bruce A nuclear facilities and at approximately 4.5 cents / kWh from the Bruce B nuclear facilities. The agreement also established certain pricing adjustments for inflation and cost overruns related to the refurbishment activities.²⁸⁸ There were a number of amendments to the agreement over the years (2007, 2009, 2011, and 2013) which changed certain terms of the contract (including pricing arrangements).²⁸⁹ As of April 2013, Bruce Power received 6.8 cents / kWh for electricity produced from its Bruce A facilities and 5.2 cents / kWh for electricity produced from its Bruce B facilities.²⁹⁰

The payments made to Bruce Power for its generated output during the post-restructuring period are higher than its costs (including lease payments and the downpayment amount paid to OPG amortized over the term of the contract). Therefore, Bruce Power is earning a return for its shareholder. The increased payment to Bruce Power for its nuclear output is applying upwards pressure on commodity rates in Ontario.

Although the contracts related to the Mississagi hydroelectric facilities are confidential, it is likely a similar story as the Bruce nuclear facilities. Pre-restructuring, when these assets were owned by Ontario Hydro, the generated electricity was priced at cost. After the restructuring, the payments for the generated electricity from the Mississagi hydroelectric facilities were priced subject to a confidential 20-year power purchase

Therefore, the 1990 – 1995 average cost figure better reflects the actual costs associated with output from the Bruce nuclear station.

The above is sourced from: Ontario Hydro, Annual Reports, 1994 and 1998.

²⁸⁷ Independent Electricity System Operator, 2014d.

²⁸⁸ Bruce Power, 2005: 43.

²⁸⁹ Ontario Power Authority, 2014h.

²⁹⁰ Ontario Power Authority, 2014i and Ontario Power Authority, 2014j.

agreement.²⁹¹ The prices paid for the generated electricity must include a return for the shareholder (otherwise no investor would have been interested in purchasing the assets). The higher prices that are likely being paid for generation from the Mississagi assets are also exerting pressure on commodity rates.

In addition, the OPA's contracts for electricity supply from new generation facilities, which came online after the restructuring, include above cost payments for generated output. In order to attract investment towards the development of generation capacity, in the post-restructuring era, it is necessary to pay a return to shareholders. In regard to renewable generators, as discussed previously, shareholders are being paid significant premiums for output from renewable sources under the OPA's procurement programs. Also, payments for output from new natural gas and hydroelectric facilities include a profit component for shareholders.^{292 293}

Overall, commodity rates are increasing during the post-restructuring period in part because the shareholders of legacy and new generators are being paid amounts associated with generated output that are above costs. The payment to generators in excess of costs is a direct outcome of the electricity sector restructuring. The dividends accruing to the private shareholders that own the Bruce Nuclear assets and the Mississagi hydroelectric assets provide no value to consumers, as these same assets provided generated output to the system at cost prior to the restructuring. Shareholder dividends were only required to allow OPG to attract the investment necessary to divest itself of these generation assets in accordance with the Market Power Mitigation Agreement.

In regard to the new generation assets contracted by the OPA, if the sector had never restructured, Ontario Hydro could have developed these same assets and designed

²⁹¹ Brookfield Renewable Energy Partners, 2002b.

²⁹² These OPA contracts are confidential so it is not possible to determine the amount of profit being earned by the shareholders.

²⁹³ A list of the OPA's current generation contracts is available at: Ontario Power Authority, 2014g.

rates to recover only the costs associated with the generated output (similar to the rates that were paid for all its generated output prior to the restructuring).

The ability to earn a profit on generated output only became necessary in order to attract private investment into Ontario's electricity generation sector. In a sector that remained vertically integrated, no payments in excess of actual costs would have been required to attract the requisite capital investment.

The remainder of the commodity rate increases that are caused by higher prices being paid for generated output from legacy generators is related to real cost pressures (increasing costs for the inputs of generation – labour and materials). These real cost pressures are associated with inflation (which results in higher costs for the inputs of generation) and would have applied pressure on commodity rates even if the sector had never been restructured.

9.3 Transmission-related Price Drivers

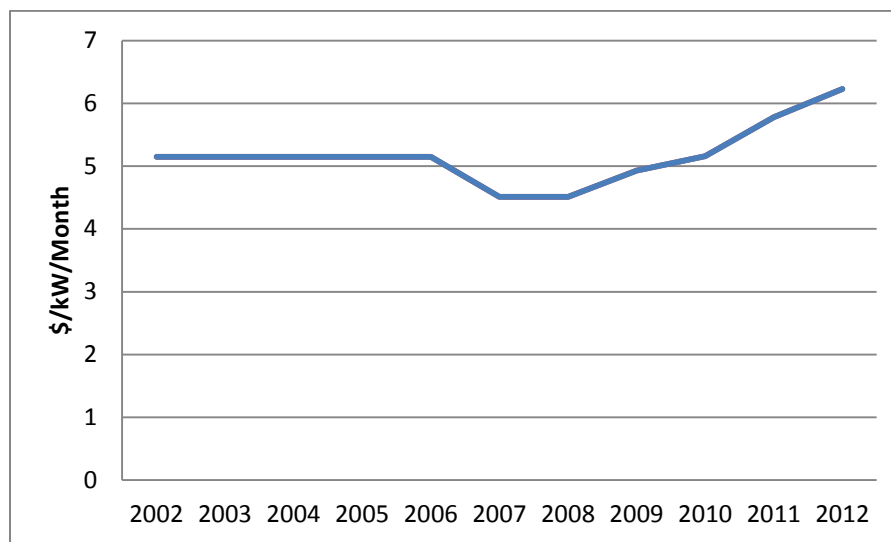
9.3.1 Transmission Prices

Prior to the electricity sector restructuring, electricity rates were bundled. Therefore, it is not possible to isolate the rates paid for transmission service in the pre-restructuring period. After market opening, transmission rates were unbundled from other service rates. As such, there is transmission pricing information available for the 2002-2012 period. However, there is no way to compare transmission prices as between the pre- and post- restructuring period.

Figure 34 highlights the uniform transmission rates applicable over the 2002-2012 period. The uniform transmission rates are designed to recover the revenue requirements (which include a return for the transmitter's shareholder) for all of the transmitters in Ontario (Hydro One, Great Lakes Power, Canadian Niagara Power, and Five Nations Energy).²⁹⁴

²⁹⁴ Ontario Energy Board, 2007: 1.

Figure 34 - Ontario Uniform Transmission Rates (2002-2012)²⁹⁵



The graph above illustrates that the uniform transmission rates remained flat at \$5.15 / kW / Month from 2002 until 2006. From 2007-2008, the uniform transmission rates fell to \$4.51 / kW / Month. In 2010, uniform transmission rates rose to a level slightly higher than in 2002 (\$5.16 / kW / Month) and reached \$6.23 / kW / Month in 2012.

Over the 2002-2012 period, uniform transmission rates increased by almost 21%. When looking at year-to-year volatility, transmission rates applied no price pressure until 2009 when the rates began to rise above the 2002 level. Therefore, the “all-in” electricity price was impacted by changes in transmission prices in the later years of the post-restructuring period being analyzed in this paper.

9.3.2 Hydro One Revenue Requirement (2011 & 2012)

There were very large increases in uniform transmission rates in both 2011 and 2012. The vast majority of these increases were due to changes in the revenue requirement of Hydro One. Hydro One is the dominant transmitter in the province, owning 97% of the

²⁹⁵ Derived from Ontario Energy Board, Uniform Transmission Rate Decisions and Rate Orders, 2002-2012.

transmission assets.²⁹⁶ Therefore, the uniform transmission rates almost entirely recover the revenue requirement of Hydro One.

Over the 2011 and 2012 period, Hydro One's revenue requirement increased significantly. In 2010, Hydro One's transmission-related revenue requirement was approximately \$1.22 billion.²⁹⁷ In 2011 and 2012, the OEB approved revenue requirements for Hydro One of approximately \$1.3 billion and \$1.63 billion respectively.²⁹⁸ This resulted in a significant increase in the uniform transmission rates.

Figure 35 disaggregates Hydro One's total transmission-related revenue requirement for 2010, 2011 and 2012. The causes of the increase in Hydro One's transmission overall transmission-related revenue requirement are discussed below.

²⁹⁶ Hydro One Networks, 2013.

²⁹⁷ Ontario Energy Board, 2010c: 3.

²⁹⁸ Ontario Energy Board, 2011e: Appendix A, 1.

Figure 35 - Hydro One Transmission – Revenue Requirement by Component (2010, 2011 & 2012)²⁹⁹

(millions)	2010	2011	2012
OM&A	\$426.2	\$418.8	\$627.1
Depreciation	\$281.3	\$301.8	\$330.8
Return on Debt	\$253.5	\$257.5	\$287.1
Return on Equity	\$256.3	\$303.5	\$352.1
Income Tax	\$40.0	\$64.0	\$60.6
Base Revenue Requirement	\$1,257.3	\$1,345.6	\$1,657.6
External Revenue	\$(18.0)	\$(33.7)	\$(28.7)
Export Revenue Credit	\$(12.0)	\$(16.0)	\$(16.0)
Other Cost Charge-related Revenues	\$(20.3)	\$(7.4)	-
Low Voltage Switch Gear Costs	\$10.8	\$11.1	\$13.9
OEB Approved Revenue Requirement (net of other revenues and costs)	\$1,217.7	\$1,299.5	\$1,626.8

Firstly, the OEB approved a revenue requirement related to Hydro One's OM&A expenses of \$418.8 million in 2011 and \$627.1 million in 2012. This reflects a modest decrease in 2011 and a substantial increase in 2012 when compared to the 2010 approved revenue requirement of \$426.2 million. The OEB's Decision with Reasons in EB-2010-0002 notes that the substantial increase in OM&A expenditures in 2012 is largely related to certain accounting changes required under International Financial Reporting Standards.³⁰⁰

The OEB approved a revenue requirement related to Hydro One's depreciation expense of \$301.8 million in 2011 and \$330.8 million in 2010. This reflects an increase in both

²⁹⁹ Derived from Ontario Energy Board, 2011e and Ontario Energy Board, 2010d.

³⁰⁰ Ontario Energy Board, 2010e: 64.

2011 and 2012 when compared to the 2010 approved revenue requirement of \$281.3 million. The increased depreciation expense is largely driven by increased capital expenditures over the 2008-2010 period related to system expansion, which was undertaken to address load growth and give access to new generation facilities.³⁰¹

The OEB also approved a return on rate base (i.e. return on debt and equity) of \$561 million in 2011 and \$639.2 million in 2012. This reflects an increase in both 2011 and 2012 when compared to the 2010 approved revenue requirement of \$509.8 million. This increase was driven by an increase in Hydro One's rate base from \$7.64 billion in 2010 to \$8.38 billion in 2011 and \$9.13 billion in 2012 as well as changes to the cost of capital parameters.³⁰² Approved rate base increased significantly over the 2010 to 2012 period due to significant capital spending during the period (on sustainment, development, and operational capital projects).³⁰³

Overall, the increased revenue requirement of Hydro One, which was caused by the items discussed above, had the effect of increasing the uniform transmission rates in 2011 and 2012. It is important to note that, with the exception of returns being paid to Hydro One's shareholder,³⁰⁴ the increases in uniform transmission rates, in the later years of the restructuring period, are caused by real cost pressures (capital expansion / replacement needs, accounting rule changes, higher costs for materials and labour, etc.) and are not directly associated with the restructuring (or post-restructuring policy changes). The cost pressures discussed above would likely have impacted the price for electricity even if the sector had never restructured.

³⁰¹ Ontario Energy Board, 2010f: 3.

³⁰² It is important to note that while the return on debt figures have increased over the 2010-2012 period, the interest rates associated with Hydro One's debt have decreased. The reason that the overall return on debt has increased over a period where interest rates have declined is that Hydro One's rate base has increased significantly over the period.

³⁰³ Ontario Energy Board, 2010g: 1.

³⁰⁴ Similar to OPG, the returns earned by Hydro One are streamed to the Ontario Electricity Financial Corporation to pay down Ontario Hydro's stranded debt. The issue of whether the net income streamed to Hydro One's shareholder is applying pressure on electricity prices is discussed in sub-section 9.5.7.

9.4 Distribution-related Price Drivers

9.4.1 Distribution Prices

As highlighted in Figure 23 in Chapter 8, distribution prices have been increasing over the post-restructuring period. From 1998-2012, distribution rates increased by over 120% on a nominal basis and increased by over 70% on an inflation-adjusted basis.

A number of changes in Ontario's electricity sector impacted the rates for distribution service. These changes are discussed below.

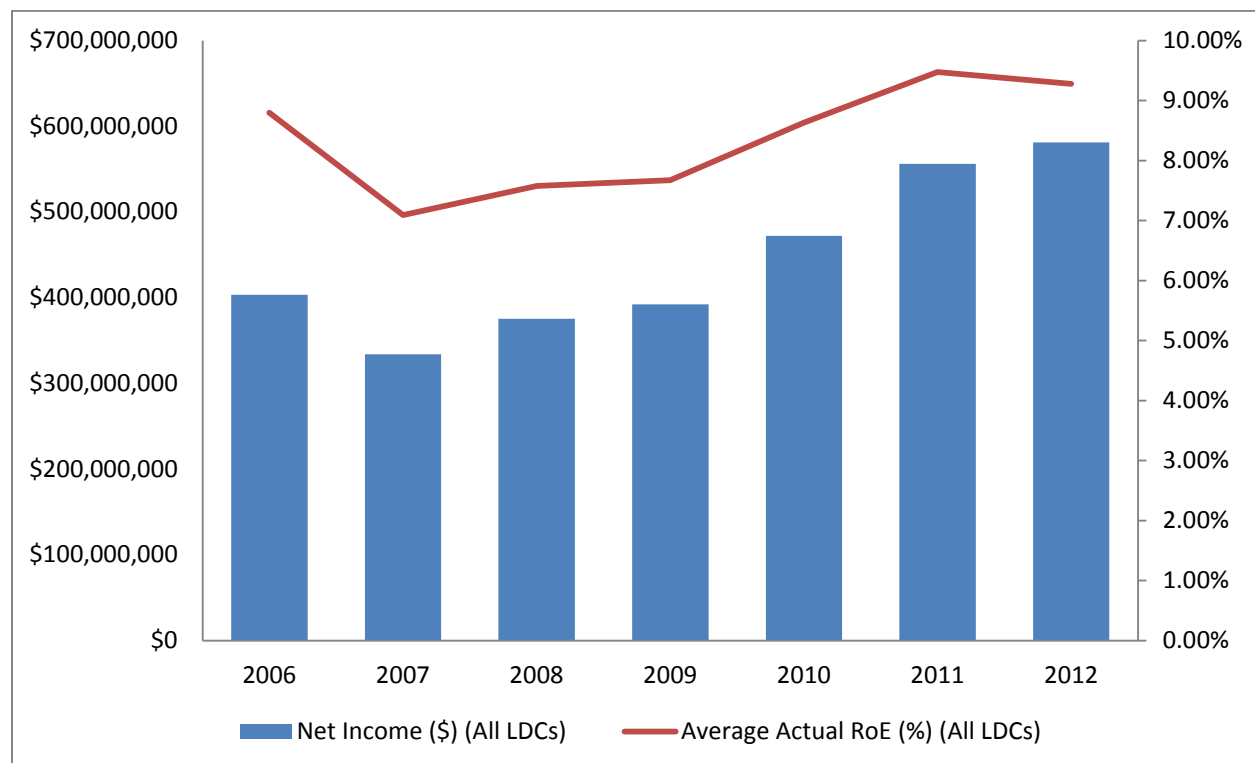
9.4.2 LDC Returns

After the restructuring, through the *Energy Competition Act*, the MEUs were required to transform into for-profit companies under the *Business Corporations Act, 1990*. This meant that the MEUs (which after restructuring became known as LDCs) became eligible to earn a return on equity.³⁰⁵ The returns earned by the LDCs are paid as dividends to their shareholders.

Figure 36 sets out the actual average return on equity earned by the LDCs in the province and the total profits earned by the LDCs over the 2006-2012 period.

³⁰⁵ Electricity Distributors Association, 2006: 22.

Figure 36 - Average Actual RoE & Total Profits (2006-2012) ³⁰⁶



As highlighted in the above chart, the total profit earned by the LDCs has risen from approximately \$403 million in 2006 to more than \$580 million in 2012. Over that period, LDCs' shareholders (primarily municipalities and some private shareholders) earned approximately \$3.12 billion in profit. Returns were earned by LDCs throughout the entire post-restructuring period (1998-2012) and therefore the total net income earned by LDCs, over the post-restructuring period, would be significantly higher than the amounts set out above.³⁰⁷ The average actual return on equity earned by the distributors was 8.4% over the 2006-2012 period.

Any returns earned by the MEUs, prior to the sector restructuring, were treated as retained earnings. Therefore, the revenues in excess of costs stayed in the utility and were directed towards utility capital projects. After the restructuring, profits were

³⁰⁶ Derived from Ontario Energy Board, Yearbook of Electricity Distributors, 2006-2012.

³⁰⁷ There is no return on equity information available for the 1999-2005 period. However, returns were being paid to the LDCs' shareholders over this period.

streamed to shareholders and the shareholders could choose to take the profits out of the utility business. This applies upwards pressure on distribution prices in the post-restructuring period as there are significant payments being made to the LDCs' shareholders (municipalities and private owners) in the post-restructuring period.

The dividend payments to LDC shareholders' are entirely associated with the restructuring and the requirement that MEUs convert to a for-profit business structure. This business structure transformation was a precursor to privatization. After the MEUs converted into corporations, they became eligible to be sold by the municipal owner to private commercial interests.³⁰⁸ A small number of municipalities did elect to sell their distribution business to private owners (for example, FortisOntario Inc. purchased LDCs that operate in Algoma District, Fort Erie and Port Colbourne³⁰⁹) but the vast majority of LDCs continue to be owned by municipalities. Overall, the privatization of the MEUs did not occur to any real extent.³¹⁰

In the absence of LDC privatization, the necessity of shareholder dividends comes into question. Essentially, the electricity sector restructuring made LDC shareholders', primarily municipalities, eligible to earn a return related to a monopoly business where no dividends had ever been previously paid and, in fact, had never been required to attract the requisite capital investment to ensure the rationale expansion and maintenance of distribution systems across the province. Since these return payments were not necessary before restructuring, there is no reason to believe that they are necessary after the restructuring (the nature of the underlying distribution systems has not changed; only the business structure has been altered). Therefore, the returns

³⁰⁸ Winfield, 2012: 135.

³⁰⁹ FortisOntario, 2014.

³¹⁰ There are a number of reasons that privatization of MEUs did not occur but it is largely associated with provincial taxation policies associated with the sale of distribution companies to private commercial interests.

Above is sourced from: C.D. Howe Institute, 2013a: 15-17.

earned by LDCs amount to economic rent (or windfall profits) which provide consumers no direct benefit.³¹¹

9.4.3 Market Opening – Distributor Transition Costs

During the lead-up to market opening (May 2002) and in the period immediately after, distributors incurred significant costs in transitioning to the newly structured market. The OEB established a Transition Costs Deferral Account³¹² which was designed to track the one-time transition costs that were associated with modifying a distributor's operational capabilities to prepare for new activities associated with the restructured electricity market.³¹³

The costs recorded in the account, and eventually recovered from electricity consumers, primarily related to the one-time IT upgrades required to facilitate the entry of retailers to the market (i.e. allowing for distributors and retailers to share customer information for billing and account settlement purposes) and allow for the billing of electricity services on an unbundled basis to all customers.

The Transition Costs Deferral Account included approximately \$178 million related to the transitional costs incurred by all of the LDCs in the province.³¹⁴ The \$178 million in costs were recovered through distribution rates beginning in April 1, 2004.³¹⁵

The transition costs incurred by LDCs due to the restructuring applied pressure on distribution rates beginning in 2004 until such time that these costs were fully recovered from ratepayers. Given that the transition costs were largely incurred to facilitate the

³¹¹ There may be some indirect benefit in terms of downward pressure on municipal taxes when the LDC is owned by a municipality. However, this is difficult to quantify.

³¹² Account No. 1570

³¹³ Ontario Energy Board, 2004a: 55.

³¹⁴ There are other transition-related costs recorded in other accounts including the Retail Cost Variance Accounts (Account Nos. 1518 and 1548). However, the amounts booked in these accounts seem to be much less material than those recorded in the Transition Costs Deferral Account.

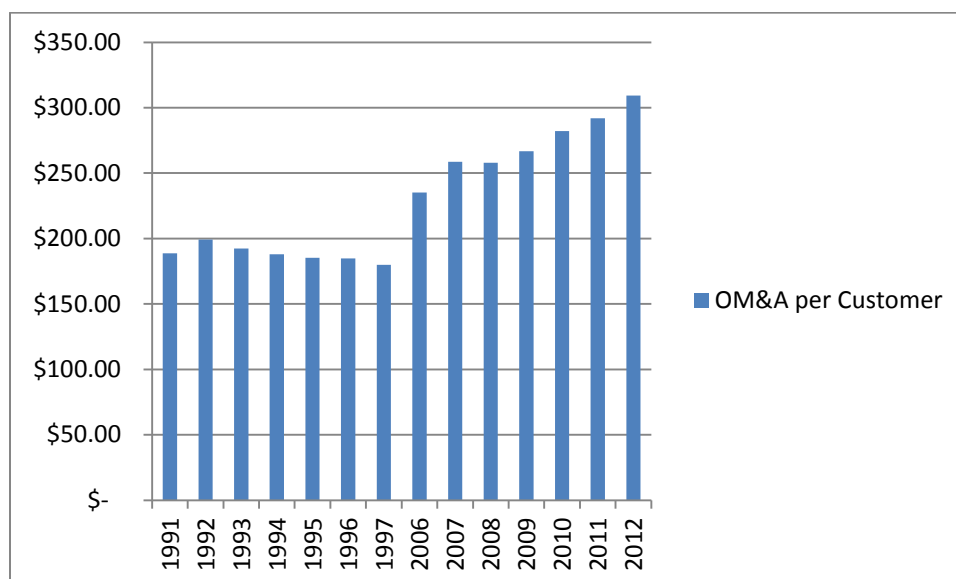
³¹⁵ Ontario Energy Board, 2004b.

operation of a retail electricity market in Ontario, electricity consumers received very little benefit from the distributors' investment. As discussed in sub-section 6.3, retail contracts typically result in consumers paying higher commodity prices and experiencing larger commodity price variances than RPP customers. Overall, consumers receive little value from the option of signing a retail contract and therefore the above noted distributor-related transition costs impacted consumers negatively by applying pressure on distribution rates.

9.4.4 Distributor – Operations, Maintenance, and Administration Expenses

Overall, the OM&A expenses of the LDCs have increased significantly over the 1991 to 2012 period as shown in Figure 37, below. In 1991, the OM&A costs were approximately \$189 per customer. In 1997, immediately prior to the restructuring, these expenses were about \$180 per customer. Therefore, over the 1991-1997 period, distribution-related OM&A expenses on a per customer basis decreased by about \$9 on a nominal basis and by approximately \$33 on an inflation-adjusted basis.

Figure 37 - Average Distributor OM&A per Customer (1990-2012)³¹⁶



³¹⁶ Derived from Ontario Hydro, Statistical Handbooks, 1990-1997 and Ontario Energy Board, Yearbook of Distributors, 2006-2012.

However, by 2006, in the first year after the restructuring where actual OM&A expense data is available, the average OM&A costs per customer were \$235. By 2012, distributors' average OM&A costs had risen to almost \$310 per customer. Over the 2006-2012 period, distributor-related OM&A expenses increased by about \$74 on a nominal basis and by approximately \$46 on an inflation-adjusted basis.

The increased OM&A expenses in the post-restructuring period result from two broad categories of expense drivers:

- General cost pressure - A significant portion of the OM&A expense increases experienced over the post-restructuring period is related to maintenance programs (for distribution infrastructure, operational control systems, vehicle and equipment fleets, and offices), staffing (maintenance, operations, administration and customer support), IT programs (billing, system control and customer support), and a number of other costs that have increased over time.³¹⁷ The above OM&A expense drivers can be viewed as amounting to real cost pressures and are not directly associated with the restructuring (or post-restructuring policy changes).
- Retailer-related OM&A expenses – Some amount of the incremental OM&A expenses that occurred in the post-restructuring period are associated with the ongoing cost of allowing customers the option of purchasing their electricity from retailers (mostly operational and administrative costs associated with retailer billing and settlement).³¹⁸ These retailer-related OM&A expenses are directly associated with the electricity sector restructuring.

Distributor-related OM&A expenses were much higher in the post-restructuring period than in the pre-restructuring period and rose more rapidly during the post-restructuring

³¹⁷ This reflects a sample of some of the OM&A cost items that have been rising during the post-restructuring period. These cost items have been canvassed from a sampling of LDC Cost of Service applications filed with the Ontario Energy Board during the post-restructuring period.

³¹⁸ In the previous section, the one-time costs of facilitating a retail electricity market were discussed (largely the initial IT upgrades necessary for billing and retail settlement). The distributor OM&A expenses discussed here are associated with the ongoing costs of facilitating a retail electricity market.

period (at least over the 2006-2012 period where actual information is available). Increasing OM&A expenses have exerted pressure on distribution rates in the post-restructuring period. The majority of the OM&A expense increase experienced is related to real cost pressures. The distribution price increases associated with real cost pressures would have occurred, to some extent, regardless of whether the electricity sector was restructured. The remainder is associated with ongoing costs of facilitating retail choice for electricity consumers in Ontario (this cost item is directly tied to the electricity sector restructuring) which, as discussed previously, provides little value as retail contracts typically do not provide the benefits that they purport to deliver.

9.4.5 Distributor Mergers

The number of distributors operating in the province reduced from over 300 in the pre-restructuring period to 77 currently. The Government's White Paper noted that the government expected that mergers of the distributors would achieve economic efficiencies. As discussed previously in sub-section 4.14, a significant number of LDC mergers occurred due to municipal policy (i.e. as municipalities amalgamated so did their respective electricity utilities).³¹⁹

There is some evidence that speaks to cost savings arising from LDC mergers. The Ontario Ministry of Energy established the "Ontario Distribution Sector Review Panel" (or the "Review Panel") in 2012. The Review Panel was established to provide expert advice to the government on how to best improve efficiencies in the sector with the aim of reducing the financial cost of distribution services. The Review Panel released its report and recommendations in 2012.³²⁰

The report noted that although a number of distributor mergers have occurred in the province, there are still a very large number of small distributors.³²¹ The Review Panel's

³¹⁹ C.D. Howe Institute, 2013a: 5.

³²⁰ Ontario Distribution Sector Review Panel, 2012: 1.

³²¹ In 2011, the median-sized LDC in Ontario served less than 20,000 customers while the average-sized LDC served about 65,000 customers.

report included some comparative analysis of costs associated with distributors of varying sizes.

The report found that OM&A expenses are typically higher, on a per customer basis, for small LDC's. The analysis shows that small LDCs (defined as having less than 12,500 customers) have OM&A costs that are approximately 75% higher than large LDCs (defined as having between 100,000 – 500,000 customers).³²² Relatedly, the report notes that there is a declining OM&A cost curve as more customers are added to the utility.³²³ The report also noted that financing costs are typically higher for small LDCs when compared to large LDCs.

The report provided some examples where mergers led to reduced distribution costs for customers:

- Veridian Connections was created through the consolidation of the utilities in Pickering, Ajax and Clarington in 1999. Veridian Connections experienced 13% savings in OM&A expenses in the first 3-years of operation. In 2005, Veridian purchased Scugog and Gravenhurst Hydro. The OM&A cost related to the new combined utility decreased by 11% (in 2006 (the year after the acquisition)).
- In 2005, Chatham-Kent Hydro purchased Middlesex Power Distribution. This purchase resulted in annual administrative cost savings of approximately \$450,000.

³²² The Review Panel's report mentions that part of the cost difference between small and large utilities is driven by the fact that small distributors have approximately 2.2 employees per 1000 customers, while large distributors have approximately 1.7 employees per 1000 customers.

³²³ A C.D. Howe Report argues that mergers likely drive cost savings up to a utility size of about 100,000 customers before diseconomies of scale become present.

The above is sourced from: C.D. Howe, 2013a: 9-10.

- In 2004, Powerstream was created through a merger of Markham and Vaughan Hydro and the acquisition of Richmond Hill Hydro. This merger resulted in about \$6.9 million in annual savings.³²⁴

The Review Panel's report concluded by recommending that the 77 existing LDCs be consolidated into 8 to 12 large regional distributors "that are large enough to deliver improved efficiency and enhanced customer focus, while at the same time maintaining connections with local communities".^{325 326}

Overall, the analysis undertaken by the Review Panel highlights that increasing the number of customers served by a distributor typically results in OM&A cost savings and reduced financing costs. A small sampling of some mergers that occurred in the late 1990s and mid-2000s confirms that cost savings can result from distributors merging. Therefore, the distributor mergers that occurred in Ontario have applied downward pressure on distribution prices over the restructuring period. The OM&A costs discussed in sub-section 9.4.4 would likely have been even higher, in the post-restructuring period, if it were not for the distribution mergers that have occurred in Ontario. LDC mergers have been beneficial to electricity consumers.

9.4.6 Smart Grid Implementation

As discussed previously in section 7.4, significant investment has been made to implement a smart grid in Ontario. The government formally set out its plan for a smart grid in Ontario in the *Green Energy Act*.³²⁷

At the end of 2014, the total amount spent on smart grid implementation was almost \$2 billion. Approximately \$1.8 billion of the total amount represent the costs associated with

³²⁴ Ontario Distribution Sector Review Panel, 2012: 10-14, 23-24.

³²⁵ Ibid: 29.

³²⁶ The Review Panel's recommendations exclude the First Nations' utilities, the non-rate regulated utilities, and Hydro One Remote Communities from its proposal for mass consolidation.

³²⁷ Ontario Ministry of Energy, 2013a.

the LDCs installation of smart meters (and related smart grid enabling improvements) and the stranding of existing metering assets. In addition, another \$160 million had been spent by the end of 2014 on the Smart Metering Entity.^{328 329}

The costs of smart grid implementation are primarily recovered through distribution rates (since the IESO was designated the role of Smart Meter Entity its costs are recovered through regulatory charges). Ratepayers have been paying charges associated with smart grid costs in their distribution rates since 2006.³³⁰ The costs of smart grid development have applied upwards pressure on distribution rates since 2006 (when customers began to pay the costs associated with smart grid implementation).

Studies indicate that the investment appears, at this early stage, to be resulting in a modest reduction in peak demand. Based on the preliminary analysis, the development of a smart grid (specifically, smart meters) in Ontario, and the related implementation of a ToU pricing structure, resulted in a modest shift in residential consumption from on-peak and mid-peak hours to off-peak times in the summer. In the winter, the province has seen an overall reduction in residential demand at all times of the day and week.

Consumers benefit from reduced peak demand in terms of avoided / deferred investment in incremental generation and transmission capacity. In addition, off-peak demand is typically supplied by lower emitting sources of electricity (i.e. baseload hydroelectric and nuclear) than on-peak demand which is largely supplied by natural-gas fired generators.³³¹ This provides an environmental benefit to electricity consumers in Ontario.

³²⁸ Auditor General of Ontario, 2014: 376.

³²⁹ It is important to note that not all of the \$2 billion in smart grid-related spending are included in the electricity prices discussed later in the paper as some of these costs were incurred after 2012. For example, in regard to the costs associated with the Smart Metering Entity, only \$100 million of those costs had been incurred by the end of 2012.

³³⁰ Ontario Energy Board, 2011f: 10.

³³¹ Ontario Ministry of Energy, 2014.

However, given the almost \$2 billion investment in smart grid infrastructure, more substantial peak demand savings will need to occur in the future for the investment to be said to be providing a large benefit to consumers.

9.4.7 Renewable Generation Connection Costs

After the enactment of the *Green Energy Act*, in 2009, the OEB established certain rules regarding connection cost responsibility associated with new renewable generation. The cost responsibility associated with renewable generation connection is based on the type of investment required to connect the generator to the distributor's system. The cost of the connection assets³³² are the responsibility of the generator. While a portion of expansion costs³³³ (up to a cap of \$90,000 per MW of renewable generation capacity) and all renewable enabling improvement costs³³⁴ are the responsibility of the distributor.³³⁵

Since 2010, distributors have begun incurring costs associated with renewable generation connection. For example, Enersource Hydro Mississauga Inc. ("Enersource") spent approximately \$60,000 in 2010 and \$200,000 in 2011 on projects which facilitate the connection of renewable generators to its distribution system. Enersource forecasted annual spending related to renewable generation connection, on average, of \$220,000 over the 2012-2016 period.³³⁶

³³² Connection assets refer to the "the portion of the distribution system used to connect a customer to the existing main distribution system, and consists of the assets between the point of connection on a distributor's main distribution system and the ownership demarcation point with that customer."

³³³ Expansion costs refer to the costs associated with expanding the distribution system to facilitate the connection of renewable generation assets. These expansion projects include: building new distribution lines to serve the connecting generator, upgrading from single-phase to three-phase lines, converting lines to operate at a higher voltage, upgrading transform stations, etc.).

³³⁴ Renewable enabling improvement refers to making upgrades to distribution system to enable the system to accommodate generation from renewable generators.

The information set out in the above footnotes is sourced from: Ontario Energy Board, 2014f.

³³⁵ Ontario Energy Board, 2014f.

³³⁶ Ontario Energy Board, 2012f: 226.

The Enersource example cited above is a common theme in the more recent Cost of Service applications of Ontario LDCs. It is fair to conclude that, to date, there has been modest spending by distributors associated with renewable generation connection. This category of spending is expected to increase in the near future as more renewable generators request to be connected to distribution systems.

Overall, renewable generation connection costs have applied pressure on distribution rates in the post-2010 period and will continue to impact rates going forward.

Consumers benefit from the LDC investment in connecting renewable generators in terms of a more environmentally-friendly electricity system that relies more heavily on sustainable and clean sources of electricity supply.

9.5 Full-Sector Price Drivers

9.5.1 Independent Electricity System Operator: Service Payments and Administrative Costs

Prior to the sector restructuring, Ontario Hydro performed the system operation functions for Ontario's electricity sector. It is not possible to unbundle Ontario Hydro's system control costs from its other costs. Therefore, there is no information available that sets out, with certainty, the costs incurred during the pre-restructuring period associated with system operation of Ontario's electricity system. However, the following facts notionally support the argument that Ontario Hydro provided system operation services at a lower cost than the IESO (who became responsible for the operation of Ontario's electricity system after the restructuring).

Firstly, the IESO pays generators a premium to provide certain 'ancillary' services to the system including: Black Start, Regulation Service, Reactive Support & Voltage Control, and Reliability Must-Run Service. In 2013, the IESO paid a total of \$95 million to generators for the provision of the noted ancillary services.³³⁷

³³⁷ Independent Electricity System Operator, 2014g.

Secondly, the IESO operates an Operating Reserve Market. The purpose of the Operating Reserve Market is to ensure that incremental electricity supply is available should an unexpected shutdown of other contracted generators occur. Generators that are selected by the IESO to provide operating reserve capacity to the system receive standby payments from the IESO (even if the capacity is not called upon to provide generated output to the grid).³³⁸

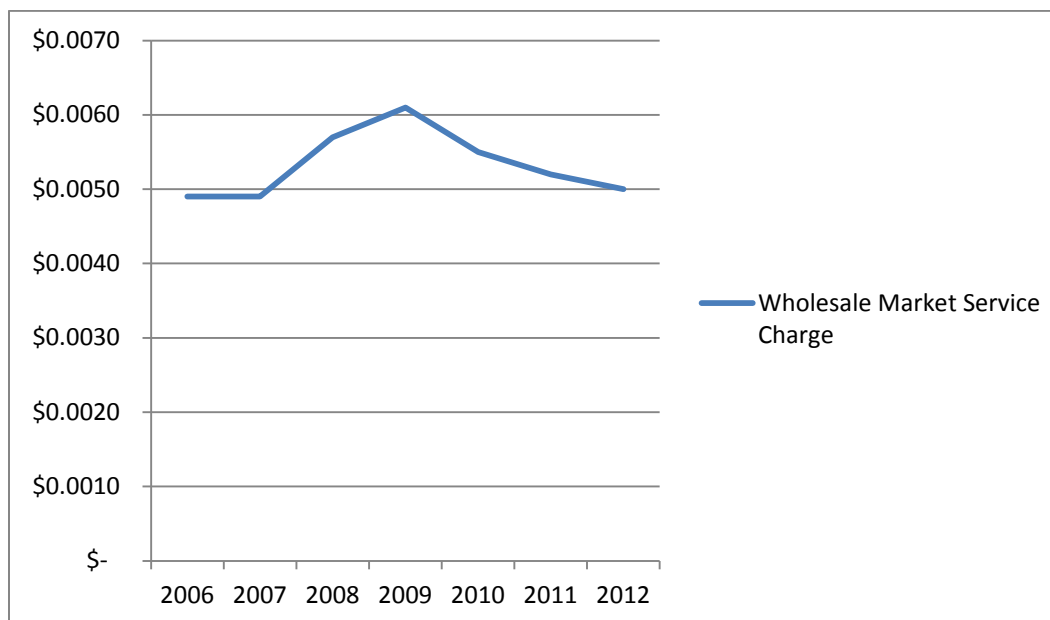
Finally, the IESO's administrative costs are likely higher than the system operation-related administrative costs incurred by Ontario Hydro as the electricity system became more complicated to operate after the restructuring (dispatch, payment and settlement complexities). The IESO's total administrative costs in 2012, excluding the Smart Meter Entity related costs which are discussed earlier in the paper, were approximately \$117 million.³³⁹

The costs incurred by the IESO, as described above, are recovered through the Wholesale Market Service Charge. Figure 38 illustrates that the charge was set at 0.49 cents / kWh in 2006 and rose to a maximum of 0.61 cents / kWh in 2009. It then fell to 0.50 cents / kWh in 2012.

³³⁸ Independent Electricity System Operator, 2014h.

³³⁹ Independent Electricity System Operator, 2013d: 31.

Figure 38 - Wholesale Market Service Charge (2006-2012)³⁴⁰



Prior to restructuring, ancillary services and operating reserve capacity were provided by Ontario Hydro's own generation assets and were therefore priced at cost (with no premium being paid for these services). In addition, it is likely that the administrative costs of the IESO are higher than the administrative costs incurred by Ontario Hydro to provide system operation services. As such, the premium payments for ancillary services and operating reserve capacity and the probable incremental administrative costs incurred by the IESO (above the costs that would have been incurred by Ontario Hydro) are responsible for some of the overall electricity price increase experienced in the post-restructuring period.

9.5.2 Ontario Power Authority: Administrative Costs

The *Electricity Restructuring Act, 2004* established the OPA and mandated it to function as the system planner, facilitate contracting for generation capacity, and design and implement conservation programs. OPA's administrative costs in 2012 were

³⁴⁰ Derived from Independent Electricity System Operator, Monthly Monitoring Reports, 2006-2012.

approximately \$59 million. These costs are recovered through the Wholesale Market Service Charge.³⁴¹

Prior to the restructuring, Ontario Hydro was responsible for those same functions. Ontario Hydro developed long term plans for Ontario's electricity system, facilitated contracting with the NUGs, and ran its own conservation programs.

It is not possible to unbundle Ontario Hydro's system planning costs from its other costs. Therefore, there is no way to say with certainty that the system planning costs during the post-restructuring period are higher than those incurred during the pre-restructuring period. However, for the following reasons, it is likely that Ontario Hydro provided the system planning functions at a lower cost than the OPA.

While Ontario Hydro had a number of NUG contracts to manage and did run energy efficiency programs throughout the 1990s, these projects were of a smaller scale than those being managed by the OPA. The OPA, in 2012, had nearly 16,000 generation contracts under its management (mostly small-scale renewable contracts) which amounts to approximately 22,500 MW of generation capacity (including capacity both in commercial operation and under development).³⁴² Ontario Hydro, prior to its unbundling, managed 2000MW of contracted NUG capacity. In addition, the OPA offers a more comprehensive suite of conservation programs than were offered by Ontario Hydro.³⁴³ This is a result of the greater emphasis that the provincial government has placed on conservation activities since 2005 (when the Third-Tranche Conservation activities began).

It is important to note, however, that the actual system planning function (i.e. developing long-term plans to meet forecasted electricity demand with proper consideration of

³⁴¹ Ontario Power Authority, 2013b: 14.

³⁴² Ibid: 8.

³⁴³ In Ontario Hydro's 1990 and 1994 Annual Reports, a small number of conservation initiatives targeted at residential, commercial and industrial consumers are mentioned. The OPA, over the years, has designed and offered a larger number of more robust conservation programs.

supply mix options and transmission constraints) is not materially more complicated in the post-restructuring period.

Overall, the OPA has a more extensive workload related to generation contracting and conservation programming than Ontario Hydro had prior to the restructuring. Therefore, it is likely that the costs incurred by the OPA are higher than those incurred by Ontario Hydro to perform similar functions.

9.5.3 Ontario Energy Board: Administrative Costs

Prior to the restructuring, Ontario Hydro set: (a) the rates for the customers that it served directly; (b) the wholesale electricity rate (commodity and transmission); and (c) the rates charged for distribution services provided by the MEUs.^{344 345} Ontario Hydro had a small team of regulatory staff which set the wholesale electricity rate and the rates for all the MEUs in the province (including its retail distribution business).³⁴⁶ Ontario Hydro also made decisions regarding capital expansion and did not require approval to implement its capital plans (building generation, transmission and distribution infrastructure).

After the restructuring, through revisions to the *Ontario Energy Board Act, 1998*, the OEB's mandate was expanded to include the regulation of the monopoly functions of the electricity sector. It is fair to say that the majority of the OEB's resources are now devoted to regulating the electricity sector including processing rate and leave to construct applications, licencing, compliance, policy development and communication

³⁴⁴ Ontario Hydro would file rate applications with the Ontario Energy Board. The OEB would review the filed applications and provide recommendations. However, Ontario Hydro required no approvals from the OEB to change its rates.

³⁴⁵ Daniels and Treblicock, 1996: 3-4.

³⁴⁶ William Harper's Curriculum Vitae found on the webpage associated with his consulting practice (Econalysis Consulting Services) highlights that from 1987 – 1989, he managed a team of 8 people in Ontario Hydro's Rates department. There may have been some support staff in other groups involved in rate setting at Ontario Hydro. As such, a fair estimate would be that less than 15 people were involved in the rate setting process at Ontario Hydro.

The referenced CV is sourced from: Econalysis, 2014: 4.

with customers. The regulatory apparatus at the OEB is much larger than it was at Ontario Hydro since the OEB's regulatory work has a wider scope (for example, the OEB's rate-setting process is much more intensive and the new retail electricity market must also be regulated). Accordingly, the costs of regulating Ontario's electricity sector are almost certainly higher in the post-restructuring period than before the restructuring.

For the 2011- 2012 fiscal year, the OEB's total administrative costs were approximately \$34 million.³⁴⁷ ³⁴⁸ The regulator's costs are recovered from the regulated entities operating in the electricity sector (electricity and natural gas distributors, electricity transmitters, as well as OPG, OPA and the IESO).³⁴⁹ These costs are passed onto electricity consumers.

9.5.4 IESO, OPA & Ontario Energy Board: Cost Summary

The nature of the restructured sector requires that there be organizations responsible for operating the system, developing system plans and economic regulation to ensure that the sector develops and operates in a cost-effective and efficient manner. As such, the IESO, OPA, and OEB play a vital role in Ontario's electricity sector (and are accountable for tasks that were previously managed by Ontario Hydro). The fact that three organizations are accountable for the functions that were previously performed by a single entity (Ontario Hydro) results in a duplication of back office functions (finance, legal, human resources, etc.). This is part of the reason that the costs associated with system operation, system planning and regulation are higher in the post-restructuring period. But it is not the only reason; the other reasons have already been discussed in the preceding sections.

Overall, the costs associated with operating the IESO, OPA and OEB are likely applying pressure on electricity prices in the post-restructuring period as Ontario Hydro

³⁴⁷ Ontario Energy Board, 2013e: 15.

³⁴⁸ Note that the \$34 million in administrative costs includes the costs associated with regulating the natural gas sector as well as the electricity sector.

³⁴⁹ Ontario Energy Board, 2014h: 3.

performed the functions that are now executed by these organizations at a lower total cost. Some portion of these incremental costs would have been avoided if the sector was never restructured but it is not possible to calculate the total avoided cost.

9.5.5 Conservation and Demand Management Spending

As discussed in section 7.3, significant investment in CDM programs has occurred over the post-restructuring period. This is a direct result of the post-restructuring policy of the provincial government (specifically, the Minister of Energy's 2004 approval of third-tranche CDM and the CDM Target directive under the *Green Energy Act*). In total, there has been a direct investment in CDM by LDCs of about \$394 million during the 2005-2012 period.³⁵⁰

There have also been costs incurred to provide incentive payments and lost revenue adjustment payments to the LDCs related to their conservation activities. Therefore, the total investment in CDM is likely materially higher than the \$394 million figure cited above.

The costs associated with the third-tranche CDM programs (including incentive payments and LRAM payments) were recovered entirely through distribution rates.³⁵¹ The costs associated with the CDM programs implemented after the Third-Tranche CDM programs concluded are recovered through the Global Adjustment Mechanism (with the exception of the incentive and LRAM payments which are still recovered through distribution rates).³⁵²

Conservation programs have been applying pressure on electricity rates since 2005 when Third-Tranche CDM programs were first implemented. However, while CDM programs cause rates to increase on \$/kWh basis, these programs result in reduced

³⁵⁰ Ontario Energy Board, 2009b: 1, Ontario Energy Board, 2012d: 8, and Ontario Energy Board, 2013b: 8.

³⁵¹ Ontario Energy Board, 2009b: 3.

³⁵² Independent Electricity System Operator, 2014a.

overall consumption (which reduces the total electricity bill for consumers). The total bill savings associated with reduced consumption more than offsets the distribution rate increases associated with CDM program. As estimated by the Ministry of Energy, for every \$1 spent on conservation, Ontario has avoided \$2 in costs to the electricity system.³⁵³ Had these costs not been avoided, they would have been collected from ratepayers.

Overall, consumers are benefitting from investment in conservation programs through an overall reduction of their electricity bill. Consumers are also deriving environmental benefits from conservation programs in terms of reduced emissions associated with a reduction in electricity demand.

9.5.6 Investment Catch-Up

As discussed in Chapter 4, there were certain electricity pricing restrictions in place over the 1993-2005 period.³⁵⁴ Some of the pricing restrictions were in place due to government policy decisions made prior to the restructuring, while the others (i.e. those occurring post-1998) are directly associated with restructuring and post-restructuring policies of government.

When prices are restricted, the revenues received by utilities are constrained. A common outcome of constrained revenues is a temporary reduction of discretionary capital spending. The price restrictions, at different times, impacted generation, transmission and distribution service providers.

It is likely that as a result of the pre- and post-restructuring price restrictions utilities reduced capital spending. Once the price restrictions were removed, investment catch-up occurred meaning utilities undertook capital projects that were previously deferred. Investment catch-up can be viewed as necessary incremental spending to address the reduced spending that occurred during the period where electricity prices were

³⁵³ Ontario Ministry of Energy, 2013c: 1-2.

³⁵⁴ The pricing restrictions that were in place over the noted period are set out in sub-section 5.2.

artificially held at levels below what is necessary to continue the maintenance and proper development of the electricity system.

There is no way to quantify the impact that investment catch-up had on electricity prices during the post-restructuring period. However, it almost certainly did occur to some extent and thus applied pressure on electricity prices during the post-2005 period (once the price restrictions were lifted).

From the consumers' perspective, investment catch-up resulted in increased electricity rates over the post-restructuring period. However, over the time period where the price freezes were in effects, consumers accrued financial benefits associated with the artificially restrained electricity prices.

9.5.7 Ontario Hydro Stranded Debt Repayment: Payments-in-Lieu of Taxes, Return Payments of OPG and Hydro One, and the Debt Retirement Charge

The Ministry of Finance determined that Ontario Hydro's stranded debt, which would arise due to the sector restructuring and the related disaggregation of Ontario Hydro, was approximately \$20.9 billion. Revenue streams that would be used to service the stranded debt of Ontario Hydro were created by the *Electricity Act, 1998*.

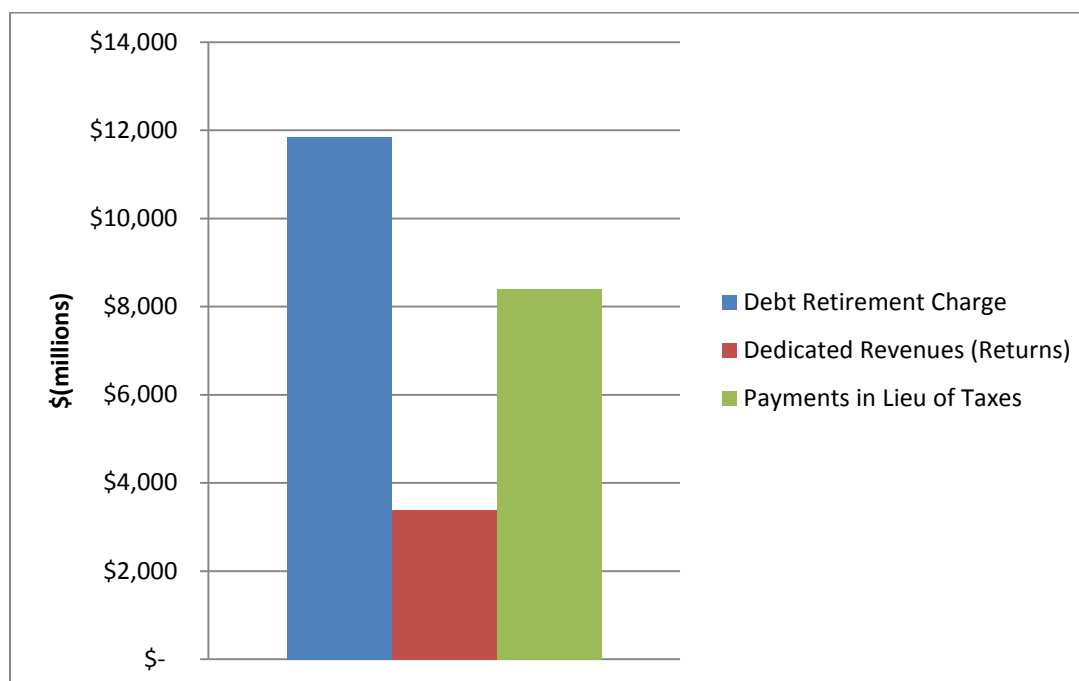
The government collects funds to stream to the Ontario Electricity Financial Corporation to pay down the legacy debt of Ontario Hydro through the following mechanisms (previously described in Chapter 5), which are all paid for by consumers in their electricity rates: (a) payments in lieu of taxes³⁵⁵; (b) return payments of OPG and Hydro One³⁵⁶; and (c) the Debt Retirement Charge^{357, 358}. Since 2000, approximately \$23.6

³⁵⁵ As noted previously, after the restructuring OPG, Hydro One and the LDCs began to make payments in lieu of taxes to the government. Payments in lieu of taxes are equivalent to corporate income, property and capital taxes paid by private corporations.

³⁵⁶ After restructuring, OPG and Hydro One began to earn a return on equity related to their regulated assets. This return is paid to the provincial government and the amount above the interest costs associated with the government's investment in the utilities is streamed to the Ontario Electricity Financial Corporation to pay down the stranded debt of Ontario Hydro. Before the restructuring, Hydro One did not earn a return on the equity portion of its capital structure. Any net earnings were treated as retained earnings and used to fund capital projects.

billion in payments have been made to the Ontario Electricity Financial Corporation to service Ontario Hydro's debt. The total payment is depicted, broken down by revenue stream, in Figure 39, below.

Figure 39 - Ontario Electricity Financial Corporation Revenues by Mechanism (2000-2012)³⁵⁹



There are significant interest costs associated with the stranded debt of Ontario Hydro. In 2012 alone, these interest costs totaled about \$1.6 billion.³⁶⁰ After financing payments, the debt has been reduced from \$20.9 billion (at restructuring) to \$12.3 billion (as of March 31, 2012).³⁶¹

³⁵⁷ Consumers are directly applied a 0.7 cent / kWh charge on their electricity consumption which is known as the debt retirement charge. The money collected from this direct charge is also streamed to the Ontario Electricity Financial Corporation to pay down what is known as the residual stranded debt of Ontario Hydro.

³⁵⁸ Auditor General of Ontario, 2011: 122-123.

³⁵⁹ Derived from Ontario Electricity Financial Corporation, Annual Reports, 2000-2012.

³⁶⁰ Ontario Electricity Financial Corporation, Annual Report, 2012: 12.

³⁶¹ Ibid.

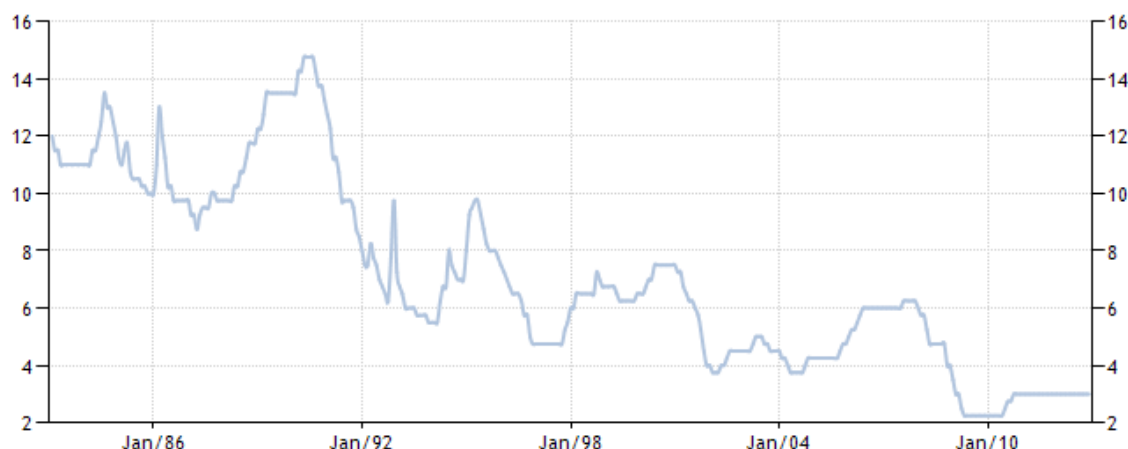
Debt repayments could be viewed as a price driver in the post-restructuring era as the amounts collected are paid by ratepayers through electricity charges. However, prior to the restructuring, some portion of the bundled electricity rate would have been designed to recover amounts from ratepayers to service the debt of Ontario Hydro. On that basis, the debt repayments should only truly be viewed as a price driver if the amounts that are being collected from ratepayers for debt repayment purposes are in excess of, or are being collected more rapidly when compared to, what was being collected by Ontario Hydro in its bundled electricity rates. Since it is not possible to know whether the sum of the amounts collected from ratepayers for debt repayments in the post-restructuring period is greater than, or accelerated compared to, what would have been collected by Ontario Hydro, it is uncertain whether debt repayments are applying pressure on electricity prices in the post-restructuring era.

9.5.8 Cost of Debt Financing

Prevailing macroeconomic conditions, which are not associated with the electricity sector restructuring, have resulted in a low interest rate environment in Canada over the post-restructuring period. The Bank of Canada Prime Rate, on average, has been significantly lower during the post-restructuring period than it was during the pre-restructuring period. After the global financial crisis in 2008, interest rates fell to a record low of 2.25% in April 2009.³⁶² Figure 40 depicts the Bank of Canada Prime Rate from 1983-2012.

³⁶² Trading Economics, 2014.

Figure 40 - Bank of Canada Prime Rate (1983-2012) (%)³⁶³



While the Bank of Canada Prime Rate provides a strong indicator of general borrowing costs, a better indicator of the cost of debt for Ontario utilities is the deemed debt rates calculated by the OEB. The OEB has set out generic debt rates for use by the LDCs in their Cost of Service applications since May 2000.³⁶⁴ The deemed debt rates established by the regulator can be considered a proxy for a market-based interest rate that would be applicable to a utility operating in Ontario and therefore provide a reasonable estimate of the interest rates experienced by the distributors over the years.

³⁶³ Ibid.

³⁶⁴ Over the 2000-2006 period, the deemed debt rates set by the Board were considered reflective of the actual debt costs of the distributor and were used as an input in the rate setting process. The Board's policy evolved after 2006 and the Board began to more commonly utilize the actual embedded cost of debt in the rate setting process. Currently, the deemed debt rate is used as a proxy for a market-based interest rate and it acts as a ceiling for debt associated with affiliates, variable rate debt instruments, and in instances where the distributor has no actual debt. The actual cost of debt is used in the rate setting process when appropriate.

The above is sourced from: Ontario Energy Board, 2009c: 50-58.

Figure 41 - Deemed Debt Rates for LDCs (2000-2012)^{365 366}



Figure 41 shows that the deemed weighted average cost of debt stays flat at almost 7% from 2000 to 2006. The weighted average cost of debt falls to about 6% in 2006 and increases to 7.2% in 2009. By May 2012, the weighted average cost of debt falls to 4.25%. This graph shows that the cost of debt, as reflected by the proxy debt rate calculated by the OEB, has decreased significantly over the post-restructuring period.

With regard to OPG, in 2008 when the OEB began to set the payment amounts associated with OPG's output, the OEB approved a weighted average cost of debt of 5.76%. For 2009, the weighted average cost of debt approved was 5.89%.³⁶⁷ For 2011

³⁶⁵ Derived from Ontario Energy Board, Cost of Capital Parameters Decisions and Cost of Capital Parameter Update Letters.

³⁶⁶ Note the following related to Figure 41:

- For the 2000-2008 period, the Board had established 4 separate deemed long-term debt rates which coincided with the size of a distributor's rate base. The information provided in the graph reflects a simple average of the deemed long-term debt rates.
- Also, regarding the 2000-2008 period, there was no deemed short-term debt rate. As such the weighted average cost of debt for that period is equal to the deemed long-term debt rate.
- For the 2008-2012 period, the Board added a deemed short-term debt rate to its cost of capital parameters. In the weighted average cost of debt calculation for the 2008-2012 period, approximately 93% of the debt is deemed long-term and approximately 7% is deemed short-term.

³⁶⁷ Ontario Energy Board, 2008b: Appendix A, 4b and 5a.

and 2012 the weighted average cost of debt approved was 5.44% and 5.50% respectively.³⁶⁸ Regarding Hydro One, the weighted average cost of debt approved by the OEB was 5.35% and 5.39% in 2011 and 2012 respectively.³⁶⁹

Due to the market conditions and the related low interest rate environment, the cost of debt, associated with capital projects undertaken during the post-restructuring period by Ontario electric utilities, has decreased significantly over the post-restructuring period (and is lower than it was during the pre-restructuring period given the relatively high interest rate environment experienced in the 1980s and 1990s as highlighted by the historical Bank of Canada Prime Rate).

Overall, the reduction in the cost of borrowing for new capital projects, experienced over the post-restructuring period, is providing some rate relief on electricity prices. Given that this reduction is associated with general market conditions, this cost reduction would have occurred irrespective of the electricity sector restructuring. Nonetheless, the reduced cost of debt applicable to the electricity utilities benefits consumers by applying downwards pressure on electricity rates.

9.6 Conclusion

I set out the major factors that have impacted electricity prices over the post-restructuring period and the cause of each (i.e. restructuring-related policies, post-restructuring policies or real cost pressure) in this chapter. In addition, I discussed the consumer impact associated with each price driver was discussed.

Electricity prices have been impacted by real cost pressures over the post-restructuring period. The price for the electricity commodity, transmission service and distribution service were all impacted, to some extent, by rising input costs. These are offset to some extent by the reduced cost of debt applicable to the sector over the post-restructuring period. The inflationary pressure associated with general economic

³⁶⁸ Ontario Energy Board, 2011c: Appendix A, 4b and 5b.

³⁶⁹ Ontario Energy Board, 2011d: 1.

conditions would have impacted electricity rates irrespective of the sector restructuring. I discussed these price drivers in order to provide a more comprehensive understanding regarding why electricity prices have risen more rapidly in the post-restructuring period.

The factors impacting electricity prices that are directly associated with either the restructuring or post-restructuring related policies of government, however, are of the most interest in terms of answering the primary research question of this thesis.³⁷⁰

There were a number of price drivers that arose directly out of the restructuring-related policies of government. Many of these factors have applied significant upwards pressure on electricity rates during the post-restructuring period and have provided little benefit to consumers. These factors include:

- Shareholder returns paid to the private owners of the generation assets (the Bruce nuclear and Mississagi hydroelectric facilities) sold by OPG to private interests and to new private generators that are contracted by the OPA;
- Shareholder returns paid to the owners, which are largely municipalities, of the LDCs; and
- Costs incurred by LDCs to facilitate the operation of a retail electricity market (both one-time transition costs incurred at the time of market opening and ongoing OM&A costs).

The costs associated with operation of the IESO, OPA and the OEB also arose directly out of the electricity sector restructuring and have applied upwards pressure on electricity rates. These incremental costs could have been avoided if the sector had never been restructured since Ontario Hydro performed the same functions at a lower total cost.

³⁷⁰ As discussed at the outset of this paper, the primary purpose of the analysis completed in this paper is to answer the question: from an economic and environmental perspective, how have Ontario's electricity consumers been impacted by changes resulting from the restructuring and post-restructuring policies of government?

Investment catch-up has also applied upwards pressure on electricity prices during the post-restructuring period. Investment catch-up is associated with price restrictions that were in place during the 1993-2005 period (spanning both the pre- and post-restructuring periods). Therefore, investment catch-up is not entirely associated with restructuring-related government policies (but some of the price limitations that were implemented by government occurred directly as a result of the restructuring). Investment catch-up can be viewed as necessary spending that occurred to address reduced capital expenditures that occurred during the prior periods where electricity prices were restricted.³⁷¹

A final factor that arose out of the restructuring was the repayment of Ontario Hydro's stranded debt. It is unknown whether the amounts collected for debt repayment are driving electricity price increases in the post-restructuring period.

In regard to the issue of distributor mergers, although the government noted that it expected that mergers would achieve economic efficiencies, the mergers that occurred were not truly associated with the restructuring policies of government. LDC mergers largely occurred due to municipal policy. While not directly related, the majority of the LDC mergers did occur around the same time that the sector was restructured and resulted in downwards pressure on distribution rates.

A number of the factors impacting electricity prices that were caused by the restructuring-related policies of government were associated with facilitating a competitive market for electricity supply in Ontario. Electricity consumers, to do this day, continue to pay costs associated with a competitive market design when competitive market forces have never, except for a brief period immediately after market opening, truly been given the opportunity to exert control over electricity prices in Ontario.

There were also a number of price drivers that arose out of government policies that were implemented in the post-restructuring period. These price drivers include:

³⁷¹ Investment catch-up has increased the price of electricity for consumers of the post-2005 period. However, consumers benefitted in terms of reduced electricity prices during the time periods that the price restrictions were in place.

- Supply mix changes;
- Renewable generation procurement programs;
- CDM programs;
- Smart grid implementation; and
- Renewable generation connection.

All of the above price drivers have applied upwards pressure on electricity rates over the later years of the post-restructuring period. However, the conservation programs offered to consumers have reduced average use, which offsets, to some extent, the overall price increases on a total bill basis.

The implementation of supply mix changes (i.e. the phase-out of coal and the inclusion of renewable generation sources) and the overall modernization of Ontario's electricity sector has been quite expensive. However, the spending has resulted in an improvement in the environmental performance of Ontario's electricity sector which benefits all the citizens of Ontario.

The price drivers that arose from the post-restructuring policies of government should be considered separate, analytically, from the price drivers that arose from the restructuring-related policies as they would have likely been implemented irrespective of the sector restructuring.

Overall, there have been a large number of items that have caused electricity rate increases during the post-restructuring period. A portion of the overall rate increase was caused by the restructuring-related government policies designed to facilitate competition in Ontario's electricity sector while another portion was caused by the post-restructuring government policies designed to make the electricity sector more environmentally sustainable. For the most part, the price drivers associated with the sector restructuring have provided little benefit to electricity consumers. While the price drivers associated with post-restructuring policies of government have made progress towards achieving environmental goals, which are beneficial to citizens. However, the progress made towards "greening" the electricity sector has come at a significant financial cost.

A summary of the price drivers is attached as Appendix A to this paper.

In the next section, I will summarize the key information provided in my thesis paper and I will set out the final conclusions.

Part C

10. Conclusion

Ontario's electricity sector underwent a fundamental transformation beginning in 1998 with the release of the *Energy Competition Act*. Over the years, the sector transitioned from a traditional monopoly model to the current "hybrid model".

Similar to some of the work cited in the literature review (i.e. Swift and Stewart, 2002 and Winfield, 2012), my paper provides a detailed understanding of the rationales, objectives and process of Ontario's electricity sector restructuring.

Under the Harris government, the electricity sector became a target of reform due to the perception that Ontario Hydro operated poorly during the early 1990s and the government's ideological belief that the private sector operates more efficiently than the public sector. The main goals of the restructuring were to reduce electricity prices through the introduction of competitive market forces and offer customers choice in retail electricity supply.³⁷²

The sector moved from the traditional monopoly model to its current structure in two steps. First, a fully competitive electricity market opened in May 2002 (based on the framework established by the *Energy Competition Act*). The competitive market, in its original form, only operated until December 2002. In response to the consumer outcry associated with rising electricity prices after market opening, the government enacted the *Electricity Restructuring Act, 2004*, which established the "hybrid model" for Ontario's electricity sector. The "hybrid model" was designed to include both competitive and regulated characteristics.

A number of other changes occurred during the post-restructuring period. The most significant of these changes include: the establishment of the OPA; the enactment of *Green Energy Act*; and distribution company mergers.

³⁷² The government also sought to enhance the safety and reliability of the electricity grid, improve the efficiency of electricity distribution through amalgamations, and reduce Ontario Hydro's legacy debt.

In order to provide a comprehensive analysis of electricity prices in the pre- and post-restructuring periods, I utilized two comparative analysis frameworks (1983-1997 vs. 1998-2012 and 1991-1997 vs. 2006-2012) to study both the “all-in” electricity price and the distribution price.

The pricing analysis that I performed in this paper was hindered, to some extent, by a lack of data available for the 1998-2005 period. Ontario Hydro stopped reporting electricity pricing information in 1997 and the OEB did not begin its reporting of electricity prices until 2006. The lack of publically-available pricing information for a period of 8 years is a concern as it makes policy analysis significantly more difficult. The government should have appointed a team responsible for gathering and reporting the same information that was reported by Ontario Hydro prior to the restructuring. This would have ensured that important pricing information was continuously available, which would have maintained public transparency and provided the government with the necessary information to allow it to evaluate whether its policy decisions were resulting in the intended outcomes. This issue teaches an important lesson for policy implementation that occurs in Ontario, and elsewhere, in the future. If crucial information is not recorded during a transition phase, the ability to evaluate policy outcomes is greatly diminished. In all cases, data gathering and recording functions must be maintained in order to allow for comprehensive evaluation.

The analysis that I undertook in this paper reveals that the “all-in” electricity price has increased more rapidly in the post-restructuring period. In addition, distribution prices have increased more rapidly in the post-restructuring period. The regression analysis confirms that the restructuring, and other post-restructuring changes, are positively correlated to the sharp increases in electricity rates observed over the post-restructuring period.

These findings arise from pricing analysis that was not previously completed and available in the academic literature. The “all-in” electricity pricing time series used was developed solely for this paper. The developed pricing dataset uses an average price for electricity (as opposed to more commonly available pricing data that is applicable to a specific class of customers). The methodology used to develop the pricing information

avoids certain pricing distortions that could potentially arise in the cost allocation process, which allows for a more effective analysis of electricity pricing over time. In addition, the regression analysis performed on the “all-in” electricity pricing dataset, which confirms the correlation between government policies and the changes experienced in electricity prices over time, was not previously available in the academic literature.

The results of the pricing analysis beg the question: why did electricity prices increase more rapidly in the post-restructuring period? To answer this, I analyzed all of the major price drivers that impacted electricity prices over the post-restructuring period.

I have also answered the question: from an economic and environmental perspective, how have Ontario’s electricity consumers been impacted by changes resulting from the restructuring and post-restructuring policies of government? This question was answered by analyzing, through both an economic and environmental lens, the price drivers that caused the rapid increase in electricity prices experienced over the post-restructuring period to determine the impact that they had on consumers.

Electricity prices have been impacted by real cost pressures over the post-restructuring period. The price for the electricity commodity, transmission service and distribution service were all impacted, to some extent, by inflationary pressure on the inputs of production related to the provision of electricity service. This inflationary pressure was offset by reduced debt financing costs applicable to electric utilities in Ontario over the post-restructuring period. These real cost pressures would have impacted electricity rates regardless of the sector restructuring.

However, a number of the price drivers impacting electricity rates are directly related to the sector restructuring.

The Harris Government believed that it would be able to reduce electricity prices for consumers by introducing competition into the sector (and by allowing private companies to enter the electricity market). In practice, a true free market system for electricity generation was in place for less than a year. While the “hybrid model” that is in place today does include a market system for wholesale electricity supply, the

competitive aspect of the pool market has been diluted by the government's decisions to procure new generation capacity almost entirely under long-term fixed price contracts and to subject OPG's prescribed generation assets to rate regulation by the OEB. The decisions that government made after the restructuring effectively moved the province away from a competitive market for electricity supply.

Although the government moved away from competition in generation, the costs associated with the competitive market structure established by the restructuring policies of government were still being paid by electricity consumers over the post-restructuring period. The market structure established by the sector restructuring requires the payment of shareholder dividends to the new owners of Ontario Hydro's legacy assets (i.e. Bruce nuclear and Mississagi hydroelectric facilities) and to the owners of new generation facilities that provide power to the grid subject to long-term power purchase contracts with the OPA. The payment of shareholder returns related to generated output only became necessary, after the restructuring, in order to attract private investment into Ontario's electricity generation sector. If the sector had never restructured, no payments in excess of actual costs would have been required to attract the requisite capital investment in generation capacity (as no shareholder returns were required by Ontario Hydro – or more accurately, the provincial government which was Ontario Hydro's shareholder - prior to the restructuring).

In addition, the IESO pays premiums to generators for the provision of certain ancillary services and reserve capacity. Prior to the restructuring, these services were provided at cost by Ontario Hydro.

The focus, in recent years, when studying electricity prices in Ontario, has been on the cost pressure applied by the post-restructuring policies of government which were designed to improve Ontario's electricity sector's environmental performance. This analysis typically ignores the fact that costs associated with facilitating a competitive market structure are also applying significant upwards pressure on electricity prices in the post-restructuring period. These are costs that could have been avoided if the sector had never been restructured. Electricity consumers were negatively impacted by the competitive market facilitation costs as any benefit that may have arose from

competitive market forces were lost when the government essentially abandoned competition for wholesale electricity supply.

Another set of price drivers arising from the electricity sector restructuring are associated with the government's objective to introduce customer choice in retail supply. Customers, after the restructuring, were given the option of purchasing their electricity from retailers under fixed-price and fixed-term contracts. Significant costs were incurred to facilitate retailer access to the market (both one-time transition costs and ongoing OM&A expenses). As discussed previously, the retail option provides little benefit to consumers since typically consumers that elect to have their electricity supplied by a retailer pay a higher price for the electricity commodity and enjoy less price stability than those customers that purchase their electricity from their LDC (and therefore pay the RPP price).

In addition, the restructuring required municipalities to transform their electric utilities into for-profit companies. This was a prelude to privatization. However, very few Ontario municipalities elected to sell their distribution businesses to private interests. The transformation undertaken to allow for the privatization of the MEUs created a structure whereby the distribution companies became eligible to earn a shareholder return (or a return on equity). Shareholder returns were never necessary prior to the restructuring to attract investment in distribution. Dividend payments to the shareholders of the LDCs have applied upwards pressure on distribution prices over the post-restructuring period and provide no benefit to consumers.

The restructuring also required the creation of the IESO (system operation) and the OPA (system planning), and the expansion of the OEB's mandate to include the regulation of the electricity sector. Ontario Hydro provided the same functions as these organizations at a lower cost. This is another reason that electricity rates have risen more rapidly over the post-restructuring period (when compared to the pre-restructuring period). In general, when a large-scale publically-owned monopoly business responsible for a wide-range of operational functions is disaggregated, incremental costs will almost certainly arise as a number of smaller new companies / agencies are established to take over the responsibilities previously held by the larger company. The incremental

costs that arise are, at least partially, caused by a duplication of back office functions. A government seeking reform by unbundling a publically-owned monopoly business must be careful to weigh the additional costs that will, almost certainly, arise from the unbundling against the forecasted benefits.

Other price drivers that impacted electricity prices are associated with the government's post-restructuring policy direction which sought to make Ontario's electricity sector more environmentally sustainable. The government through policy directives issued during the post-restructuring period and the enactment of the *Green Energy Act*, sought to "green" Ontario's supply mix (through the phase out of coal-fired generation and the procurement of renewable supply), reduce electricity demand through conservation programs and reduce peak electricity demand through the implementation of a smart grid (and related ToU pricing). The government has been quite successful at achieving these environmental goals (which have achieved a significant reduction of greenhouse gas emissions). While these post-restructuring policies have benefitted consumers from an environmental perspective, significant costs have been incurred which have applied pressure on electricity rates over the post-restructuring period. It is likely, given the global trend towards increased reliance on renewable generation, that many of the government's environmental policies would have occurred irrespective of the sector restructuring. As such, the post-restructuring policies of government that have impacted the price of electricity should be viewed as, analytically, distinct from the restructuring-related policies of government.

In my paper, the results are clear that, on a qualitative basis, the government's post-restructuring policies were beneficial to consumers as they did make Ontario's electricity sector more environmentally-friendly. However, a detailed quantitative cost-benefit analysis could be useful to determine whether the environmental benefits accrued truly outweigh the financial costs incurred to achieve these benefits. This type of study is yet to be completed in a manner that considers all of the post-restructuring environmental policies of government.³⁷³

³⁷³ Dewees, 2013, did provide a quantitative cost-benefit analysis of renewable generation in Ontario. However, it did not evaluate policies associated with conservation and smart grid implementation.

There were also several price drivers that were not solely related to either the restructuring or post-restructuring policies of government. For example, incremental capital spending (investment catch-up) that occurred after various price freezes were lifted applied price pressure on electricity rates in the post-2006 period. The price freezes are attributable to both pre-restructuring and restructuring policies of government. Another example are the distribution mergers that occurred after the restructuring. These mergers occurred largely due to municipal policy and applied downward pressure on electricity prices over the post-restructuring period.

The specific conclusions set out above with regard to the reasons that electricity prices rose more rapidly in the post-restructuring period, and how consumers have been impacted by these changes, are a result of the detailed price driver analysis that I completed for this paper. As mentioned in the literature review, Dewees, 2012, did provide some analysis of the major price drivers that have impacted electricity prices in Ontario over the post-restructuring period. However, the number of price drivers considered (and the level of detail included in the analysis of each specific price driver) in this paper is well beyond what was previously available. The detailed nature of my analysis provides a comprehensive understanding of the reasons why electricity prices rose more rapidly in the post-restructuring period and offers a well-considered evaluation of the impact that these price drivers had on electricity consumers in Ontario. The nuanced understanding of the impacts that the government's pre- and post-restructuring policies had on consumers provided by this paper fills a gap in the existing literature.

In general, analysis of electricity prices over extended timeframes is extremely complicated to perform. It is not possible to say with certainty whether the prices paid for electricity today are higher than they would have been if the sector was never restructured (this is the "unsolvable counterfactual problem" cited in the limitations section of the paper). The most effective way to address the counterfactual problem is to complete a comparative analysis of Ontario's electricity sector with the electricity sectors of other jurisdictions that have also undergone sector reform to determine whether the results experienced in Ontario are similar to those experienced in these

other jurisdictions. This is another area where additional work should be completed in the future.

Although my paper does not, directly or indirectly (through comparative analysis), address the counterfactual problem, the analysis that I have undertaken in this paper demonstrates that electricity prices have increased more rapidly over the post-restructuring period (when compared to the pre-restructuring period).

My analysis also sets out the reasons that prices rose more rapidly in the post-restructuring period and discusses how the changes to the sector, resulting from the restructuring and post-restructuring policies of government, have impacted electricity consumers.

Essentially, the restructuring policies of government sought to reduce electricity prices through competitive market forces (and the privatization of electricity infrastructure). The government, after market opening, moved away from a free market system for electricity supply and very little privatization occurred (particularly related to the distribution assets held by municipalities). However, the competitive market structure established by the restructuring, which requires the payment of shareholder returns, continued to exist. Therefore, consumers have been paying, through their electricity rates, the costs associated with a market structure that was designed to allow for competition even though, in practice, competition does not exist in the sector. This has negatively impacted consumers through upwards pressure in electricity rates. In addition, the restructuring policies of government have increased the price for electricity service as significant costs were incurred to provide customer's options for retail electricity supply. Retail contracts, as noted previously, are typically not beneficial to consumers.

Overall, while the restructuring policies of government have generally impacted consumers negatively, the post-restructuring policies of government have largely provided consumers benefits in terms of a cleaner generation supply mix and reduced demand for electricity (however, these environmental benefits have come at the cost of increased electricity rates).

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Appendix A - Summary of Price Drivers

The major factors that impacted electricity prices over the post-restructuring period were discussed in the Chapter 9. These factors, or price drivers, were categorized on the basis of causation and analyzed from both an environmental and economic perspective to determine whether consumers have benefitted. The following table summarizes the information set out in the noted chapter.

Price Driver	Section	Causation	Consumer Impact
Commodity-related Price Drivers			
Supply Mix Changes	9.2.2	Post- Restructuring Government Policies	Environmental benefit arises due to a cleaner supply mix. This environmental benefit comes at the cost of increased commodity prices.
Renewable Generation Procurement Programs	9.2.3	Post- Restructuring Government Policies	Necessary to attract renewable generation projects (which achieves environmental goals). However, generous program design is causing unnecessary incremental pressure on commodity prices.
Higher Payments for Generated Output from Legacy Generators and New Generators	9.2.4	Restructuring & Real Cost Pressure	<p>Above cost payments made to the private companies that purchased the Bruce and Mississagi assets and to the shareholders of new generation facilities in the post-restructuring period are resulting in increased commodity prices. These return payments provide no benefit to consumers and could have been avoided if the sector was never restructured.</p> <p>The underlying costs of the generated output from legacy generators that were online prior to the restructuring are increasing due to general economic conditions (i.e. the inputs to generation are more expensive). This applies pressure on commodity prices. However, rate increases associated with underlying cost pressure would have occurred irrespective of the sector restructuring.</p>

Price Driver	Section	Causation	Consumer Impact
Transmission-related Price Drivers			
Hydro One Revenue Requirement Increase	9.3.2	Real Cost Pressure	The increases in transmission rates are caused by real cost pressures experienced by Hydro One (capital expansion / replacement needs, higher costs for materials and labour) and would likely have impacted the price for electricity even if the sector had never restructured. These cost pressures are increasing the overall price of electricity for consumers.
Distribution-related Price Drivers			
LDC Returns	9.4.2	Restructuring-related Government Policies	Above cost payments for generated output applied pressure on distribution rates over the post-restructuring period. The payment, by ratepayers, of a shareholder return provides no direct benefit to consumers as the necessary capital investment in distribution assets was available prior to the corporatization of the MEUs.
Distributor Transition Costs	9.4.3	Restructuring-related Government Policies	<p>Transition costs incurred by distributors associated with market opening (and more specifically, the facilitation of a retail electricity market) resulted in pressure on distribution rates after 2004.</p> <p>Retail choice in electricity supply provides little value to consumers as the retail option typically results in the consumer paying a higher price for the electricity commodity and experiencing greater rate instability.</p>
Distributor OM&A Expenses	9.4.4	Real Cost Pressure & Restructuring-related Government Policies	The majority of the increase in distributor OM&A expenses is associated with inflationary impacts which have operated to increase the costs of providing distribution service (materials, labour, IT support, etc.). These increased costs would have likely occurred irrespective of the sector restructuring.

Price Driver	Section	Causation	Consumer Impact
			<p>The remainder of the increase in OM&A expenses is associated with the ongoing costs of facilitating a retail electricity market. Retail choice in electricity supply provides little value to consumers.</p> <p>Increased OM&A costs incurred by distributors applied pressure on the distribution rates applied to electricity consumers in the post-restructuring period.</p>
Distributor Mergers	9.4.5	Municipal Policy & Hydro One Acquisitions	LDC mergers provided benefits to consumers in the form of reduced OM&A expenses (compared to the level of OM&A costs that would have been present in the sector if the number of LDCs did not decrease) which applies downwards pressure on distribution rates.
Smart Grid Implementation	9.4.6	Post-Restructuring Government Policies	The costs associated with smart grid implementation applied pressure on distribution rates in the post-restructuring period. However, consumers are receiving modest benefits from the smart grid spending in terms of deferred avoided / deferred investment in incremental generation and transmission capacity and reduced emissions associated with electricity generation. However, given the substantial investment in smart grid infrastructure, a larger reduction in peak demand will need to occur in the future in order to justify the investment.
Renewable Generation Connection Costs	9.4.7	Post-Restructuring Government Policies	The costs associated with the connection of renewable generators by LDCs applied pressure on distribution rates in the post-restructuring period. Consumers benefit from this investment by LDCs as it allows renewable generators to be added to Ontario's supply mix which achieves environmental goals.

Price Driver	Section	Causation	Consumer Impact
Full-Sector Price Drivers			
IESO Service Payments and Administrative Costs	9.5.1 and 9.5.4	Restructuring-related Government Policies	<p>The above cost payments made for certain ancillary and operating reserve services along with the administrative costs of the IESO (which are likely higher than those incurred by Ontario Hydro to provide the system operation function) have applied pressure on electricity rates over the restructuring period. This has increased the price of electricity service for consumers.</p> <p>While an independent system operator is necessary in the context of the restructured electricity sector, some portion of the incremental costs associated with system operation could have been avoided if the sector had never been restructured.</p>
OPA Administrative Costs	9.5.2 and 9.5.4	Restructuring-related Government Policies	<p>The higher costs incurred by the OPA to provide the system planning function has applied pressure on electricity rates over the post-restructuring period. This has increased the price of electricity service for consumers.</p> <p>The OPA provides a necessary service in the context of the restructured electricity sector. However, some portion of the incremental costs associated with system planning could have been avoided if the sector was never restructured.</p>
OEB Administrative Costs	9.5.3 and 9.5.4	Restructuring-related Government Policies	<p>The higher costs incurred by the OEB to provide regulatory oversight in the electricity sector has applied pressure on electricity rates over the post-restructuring period. This has increased the price of electricity service for consumers.</p> <p>The OEB provides a necessary</p>

Price Driver	Section	Causation	Consumer Impact
			service in the context of the restructured electricity sector. However, some portion of the incremental costs associated with the OEB's operations could have been avoided if the sector was never restructured.
CDM Spending	9.5.5	Post-Restructuring Government Policies	While CDM spending applied upwards pressure on electricity rates over the post-restructuring period, consumers are benefitting in terms of reduced total electricity bills (as average consumption has declined). Environmental benefits are also achieved through reduced emissions associated with reduced electricity demand.
Investment Catch-up	9.5.6	Pre-Restructuring and Restructuring related Government Policies	<p>Due to the varying price restrictions that were in place over the 1993-2005 period, utilities reduced discretionary capital spending. Once the price limitations were removed, investment catch-up occurred which applied upwards pressure on electricity rates. Investment catch-up can be viewed as necessary spending to address the reduced capital expenditures that occurred during the prior periods where electricity prices were restricted.</p> <p>Investment catch-up has increased the price of electricity for consumers over the post-2005 period. However, consumers accrued financial benefits in terms of lower electricity prices during the time periods that the price freezes were in effect.</p>
Ontario Hydro Stranded Debt Repayment	9.5.7	Restructuring-related Government Policies	Amounts are collected from ratepayers through a number of mechanisms to service the legacy debt of Ontario Hydro (payments in lieu of taxes, returns payments of OPG and Hydro One, and the DRC).

Price Driver	Section	Causation	Consumer Impact
			<p>If the sector had never restructured, some portion of the bundled electricity rate would have been designed to recover the costs associated with Ontario Hydro's debt.</p> <p>It is uncertain whether the amounts collected for debt repayment purposes in the post-restructuring period are greater than, or accelerated compared to, what would have been collected by Ontario Hydro for the same purpose. As such, it is uncertain whether debt repayments are applying pressure on electricity prices in the post-restructuring era.</p>
Cost of Debt	9.5.8	Real Cost Pressure	<p>The cost of debt in the post-restructuring is significantly lower in the post-restructuring than it was during the pre-restructuring period. The reduction in the cost of debt would have occurred irrespective of the electricity sector restructuring.</p> <p>The reduction in the cost of debt applicable to Ontario's electricity utilities is applying downwards pressure on electricity rates during the post-restructuring period which is beneficial to consumers.</p>