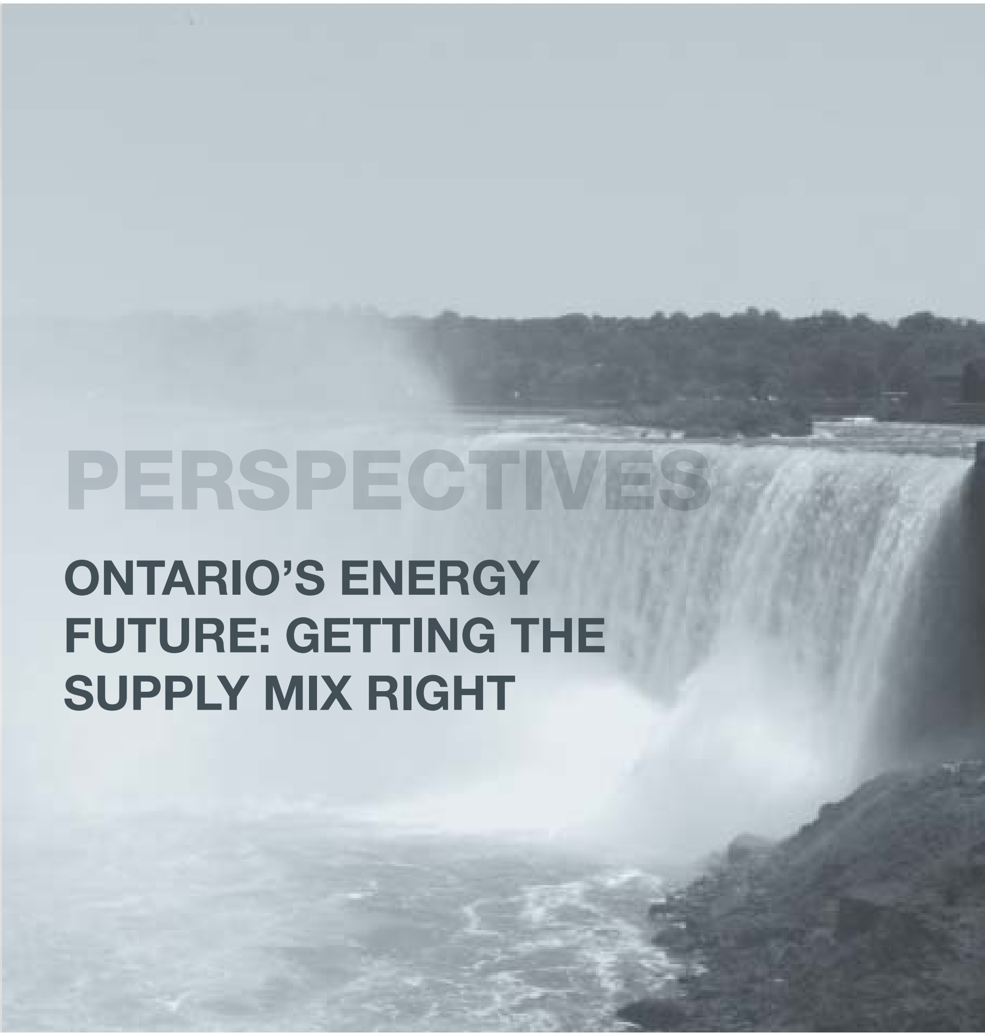


PERSPECTIVES

ONTARIO'S ENERGY FUTURE: GETTING THE SUPPLY MIX RIGHT

SECOR

INTRODUCTION

CONSIDERING A BUSINESS PERSPECTIVE WHEN FORMULATING ONTARIO'S POLICY FOR A SUSTAINABLE ENERGY FUTURE

The Ontario Power Authority (OPA) is submitting an updated Integrated Power System Plan (IPSP) to help Ontario anticipate and meet its long-term electricity needs. Up to now, planning has been based on a risk-mitigation perspective focused on peak capacity and provincial supply self-sufficiency. In SECOR's view this is fundamentally expensive and has led to overcapacity.

An increasingly relevant question is: "Are there other perspectives which can help reduce costs and safely meet the supply needs for Ontario's future?"

In the point of view, presented here, SECOR examines the fundamental drivers of the OPA's twenty-year projection of Ontario's energy needs, contrasted against an operational planning perspective. This contrast brings several issues to light:

- The province finds itself in an expensive oversupply situation
- Many facilities will see lower than optimal utilization, implying higher than anticipated costs
- Adjusting the mix to optimize costs will likely affect all generation types

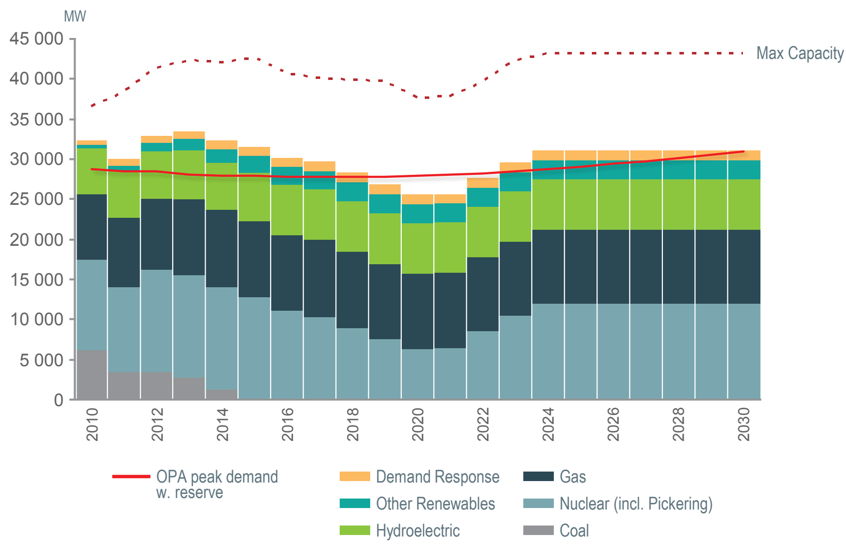
SECOR offers this Perspective to help develop a sustainable business environment for Ontario's power-producing economy at a reduced cost to Ontario's rate payers.

ONTARIO'S CURRENT PLANNING FORECAST

The backdrop for the development of the next IPSP has been the government supply mix directive, Ontario's Long Term Energy Plan (LTEP), and the OPA's long-term capacity and demand forecast for Ontario's energy future, released as part of the IPSP consultation process. As replicated below, the OPA's long term forecast illustrates the expected supply-mix contribution to meet peak summer demand to 2030:

Ontario's Energy Picture to 2030

Stacked by magnitude, De-rated and maximum capacity compared to OPA peak demand including reserve



This picture suggests that planned capacity will be sufficient, if not excessive in the short term, and will marginally exceed demand 10 to 20 years from now. A potential supply shortfall has been identified during the planned refurbishments of the nuclear fleet between 2019 and 2022. The OPA has expressed confidence that this gap is not as concerning by pointing out that this capacity forecast does not include all potential sources, particularly imports, which have historically supplied ~2,000 MW of our peak period demand[I].

An examination of the key drivers and assumptions underlying the OPA forecast is presented here to illustrate several implications for power generators and rate payers.

I Calculated from average peak imports during July and August (summer) months using IESO 2009-2011 data

THE PEAK-RISK MITIGATION POLICY PERSPECTIVE

The government's supply directive and the OPA's portrayal of the long-term forecast have been predicated on a peak-demand, risk-management strategy to assess the adequacy of power-generation capacity in Ontario. With the objective of mitigating the risk of under-capacity in the face of possible surges in demand, several strategic assumptions have been used:

1. **Peak-demand forecasting:** Demand estimates in Ontario are taken from summer peak requirements, which represent the highest level of demand throughout the year.
2. **De-rated capacity:** Supply capacity estimates in Ontario are taken from summer peak capacity contributions, which represent the lowest level of individual facility capacity utilization expected throughout the year.[II]
3. **Operating reserve margin:** Calculations of peak demand in Ontario include a reserve margin, which is the amount of supply resources in excess of demand that is required to meet the reliability criteria of annual loss of load expectation (LOLE)[III] of 0.1 days/year.
4. **Self-sufficiency of the province:** External sources of supply have been discounted in establishing the peak-risk mitigation plan.

To set its reserve requirements, the OPA uses the Northeast Power Coordinating Council (NPCC) regional reliability standards, which establish criteria to ensure that demand will not exceed available generating capacity more than once every 10 years, which translates to an average of less than 0.1 days (2.4 hours) per year. The supply planning target used is therefore the highest imaginable 3 hour consumption level that could occur in a year. Any capacity above this line will not ever be used. This peak-risk mitigation approach more than ensures against Ontario ever encountering a shortage situation, except for the period where refurbishments are planned.

From a policy perspective, planning based on maximum demand requirements and minimum supply capacity expectations may make sense to protect our energy consumers and economy from disruptions, such as the one the province witnessed during the blackout in 2003.[IV] Avoiding such a disruption is important for the provinces economic stability; however, this risk mitigation approach comes at a cost which may not provide rate payers with optimal cost-benefit returns.

To understand these costs, it is helpful to look at the future forecast from the perspective of a business seeking to supply power capacity in a sustainable, economic manner.

II Generating facilities are operated at less than maximum capacity for reasons such as prolonging operational life, lack of wind or solar inputs, cooling constraints, etc. and are at their lowest point during the summer

III LOLE is a common reliability index used to assess generating capacity adequacy. It represents the number of days per year, on average, in which the load exceeds the available generating capacity, and hence, there is an expectation that firm load will be disconnected to resolve resource deficiencies.

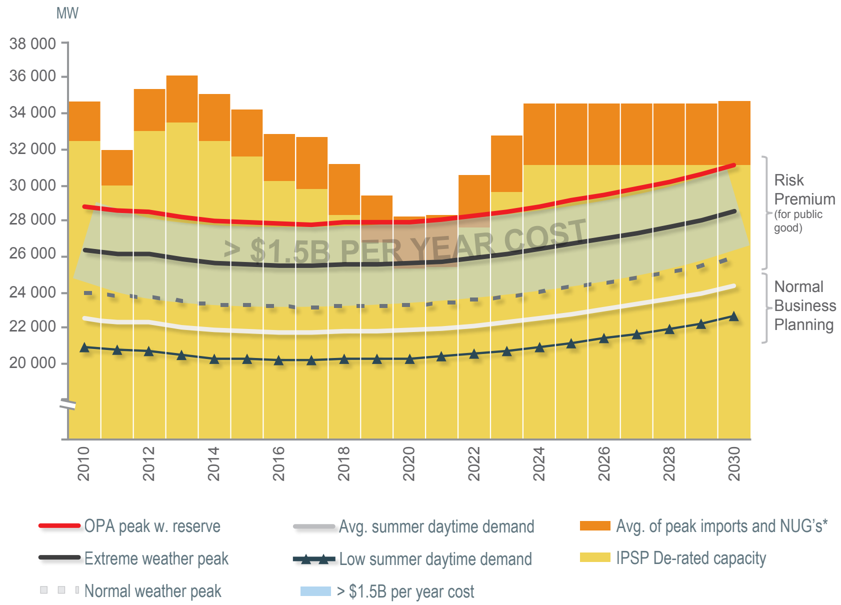
IV It is helpful to recall, that the 2003 Blackout was primarily caused by transmission system issues in the US, and not generation supply failures in Ontario

THE BUSINESS OPERATIONAL PLANNING PERSPECTIVE

The cost implications of a peak-risk mitigation approach can be illustrated by portraying system capacity under the assumption that everything is managed by a single business. Under this hypothetical scenario, normal business decisions would be focussed on assessing expected demand, considering all available options, such as imports, and assessing the economic implications of high and low demand cases.[V]

RISK-MITIGATION COMPARED TO BUSINESS PLANNING

OPA and IESO data, De-rated capacity compared to various summer demand scenarios



*NUG capacity is included within OPA Natural Gas forecast until expiry of the contracts. SECOR's NUG forecast reflects the assumption that the NUG contracts are renewed per ministerial directive.

This exhibit contrasts available capacity with expected ranges of possible demand, specifically:

1. **OPA peak with reserve:** An OPA value, incorporating a reserve reflecting the NPCC standard.
2. **Extreme weather peak:** An Independent Electricity System Operator (IESO) expectation of the highest peak demand based on high temperature weather conditions.

V Top develop this business planning perspective, the OPA's 2030 projections were compared to 2011 IESO generation data, which reflects similar demand patterns to 2024, when all future capacity is expected to be online. Imports are calculated from average peak imports during July and August (summer) months, using IESO 2009-2011 data.

3. **Normal weather peak:** An IESO estimate of highest normal peak demand day in summer under nominal weather assumptions.
4. **Average summer daytime demand:** Average of daytime demand during summer months (July-Aug).
5. **Low summer daytime demand:** Average of lowest daytime demands during higher demand months (July-Aug).

To optimize its business interests, a power generator would evaluate how much capacity could be built to efficiently provide power while also generating a profit. Operationally, capacity planning for a typical business is not done based on maximum peaks or minimum (unexpected, but still possible) scenarios; business plans are made based on average expected demand requirements, balanced against reliability requirements. Peak times will provide increased profits as demand increases, but building capacity based on peak estimates alone can result in costly over-capacity. It is also worth restating that extreme summer peak situations should only occur on rare days every few years.

Peak risk mitigation policy results in more capacity than a normal business in an unregulated free market would construct. This extra capacity does have value in the form of a public good that mitigates peak supply risk. To create risk mitigation capacity for the public good, the Ontario market has introduced regulated pricing to encourage such things as peaking gas supply for extreme weather and other conditions, something that normal market-price based business decisions would not otherwise develop. Based on the expected supply from this capacity, the cost of our surplus peaking capacity to mitigate extreme peak risk is greater than $1.5B per year.[VI] While this could be viewed as the premium for an equivalent insurance policy, the question is whether this cost has been materially optimized.

VI Calculated using OPA 2030 projections of generation breakdowns (~7% for gas) and price ranges using 2010 indexed $/MWh's. See the IESO / OPA Average life cycle customer costs.

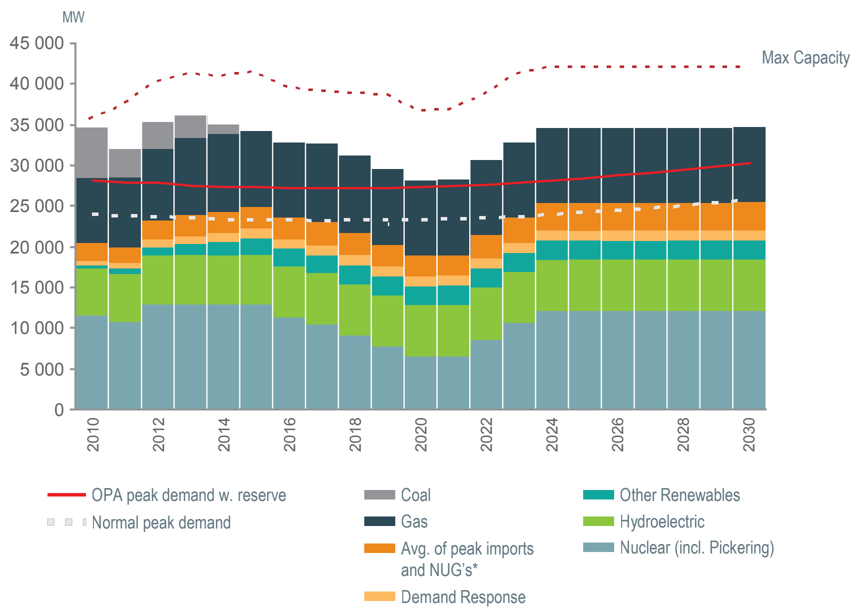
IMPLICATIONS ON BUSINESS OPERATIONS

While the simplistic model shown previously assumes a single, homogenous supplier, in reality, the Ontario market consists of multiple businesses offering different supply types. The IESO operates under a number of physical market operating guidelines about how these different energy generation sources will be turned on or off to meet demand. Nuclear and hydro-electric generators provide steady baseload power. Nuclear shutdowns entail operational delays and are undesirable for regulatory and technical reasons. Hydro can be well matched to the daily profile and diverted when power is not required but has limits to its ability to stem useable water flow. Other renewables provide power intermittently, when the wind blows and the sun shines for example, and Feed-in-Tariff (FIT) program commits to purchase the power if produced, making it highly desirable to use it when available. Gas and coal are generally well suited to provide controllable power, which means they are first to be turned off in cases of over-capacity and last to be turned on as demand peaks.

Re-ordering the supply types to reflect these on-off decisions and adding in the average amount of imports and NUG energy supply as their contracts are renewed provides the following illustration of how much each power source may be utilized:

ONTARIO'S ENERGY PICTURE TO 2030

Stacked to reflect on-off decisions, including imports/NUG's, De-rated capacity compared to various peak demand cases



*NUG capacity is included within OPA Natural Gas forecast until expiry of the contracts. SECOR's NUG forecast reflects the assumption that the NUG contracts are renewed per ministerial directive.

If physical market operations were as simple as this exhibit, one could argue, that the only reason we have coal plants staffed and maintained in 2013/14 is to provide excess reserve capacity over and above the worst case need for emergency operating procedures for a few summer days. One could also argue that the province's gas supply is unlikely to be needed for more than sporadic operations in the next 5 years, until required to mitigate for nuclear refurbishment and to offset wind intermittency during times of peak demand. This illustration also suggests that nuclear, hydro and renewables will be fully and economically utilized, while gas operations will not be.

IMPLICATIONS FOR ONTARIO'S FUTURE SUPPLY MIX

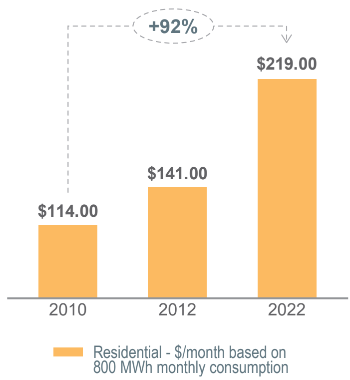
The IPSP planning framework behind the LTEP has been based on a risk-mitigation perspective focused on peak capacity and self-sufficiency. Fundamentally, this has led to a surplus of supply capacity that presents several future planning challenges. The current balancing of risk and costs has the following implications:

1. Costs are high
The OPA has acknowledged the cost implications of the current energy plan, projecting that rate payer costs can be expected to almost double by 2022.

2. Costs may get higher
Continued overcapacity will lead to underutilized assets. If underutilization is too high, the ability to provide safe and reliable capacity becomes less efficient and more expensive. It is expensive to maintain the operational readiness of a facility which is only needed a few days per year. Improving this efficiency implies reduced capacity utilization of other assets, such as through nuclear lay-ups or unused FIT commitments.

RATE PAYER PRICE PROJECTIONS

Ministry of Energy LTEP 2010-2030 projections, nominal $'s, includes HST



3. Many factors can impact costs without reducing reliability
Taking a business operational perspective suggests that decisions regarding supply mix optimization should consider:

- Imports and NUGs (contract structures, renewals, etc)
- The operational viability of the supply base
- The cost effectiveness of both demand and supply approaches to peak risk mitigation
- Refining the way transmission and distribution are included in overall reliability calculations

4. Planned capacity will likely need to be reduced across all generation types
This operational perspective raises the provocative questions of whether the province needs all of its various generation assets and whether the ones they do sustain will be operationally viable in an underutilized environment. If reducing capacity is desired, it likely means considering changes to all elements of the supply mix, and hence could affect everyone in the energy system.

It appears clear that considering several business implications may help the government optimize its priorities in the coming months as it sets the course for our energy future.

REFERENCES

- Ministry of Energy - Supply Mix Directive, 2011
- Ministry of Energy - Long Term Energy Plan, 2010
- OPA - IPSP Planning and Consultation Overview, 2010
- IESO - Reserve margin requirements, August 24, 2011
- IESO – 18 Month Outlook Update, from December 2011 to May 2013 and from September 2011 to February 2013
- North American Electricity Reliability Corporation (NERC) and North East Power Coordinating Council (NPCC) reliability standards
- Ministry of Energy – Negotiation of new contracts with non-utility generators, November 23, 2010

ABOUT SECOR'S ENERGY PERSPECTIVES

SECOR is developing a series of perspectives on the emerging issues in Ontario's electricity market which will further explore such topics as:

- Implications for gas generation
- Cost legacy implications
- Alternative supply mix options
- Emerging opportunities for entrepreneurs

THE AUTHORS

MARC BROUILLETTE, PARTNER
mbrouillette@secorgroup.com

Marc is the lead of SECOR's energy practice in Toronto, with 25 years of industry experience. He is a senior strategy consultant focusing on industry analysis and restructuring strategy and the development of business models for emerging opportunities. Marc specializes in the creation of public/private multi-stakeholder business models and the negotiation of the associated contract relationships involving domestic and/or international stakeholders.

ANDREA BALDWIN, ASSOCIATE PRINCIPAL
abaldwin@secorgroup.com

Andrea is an Associate Principal in SECOR's strategy practice and member of the Toronto energy team. Andrea has a breadth of experience in the retail, resources, and financial services sectors with emphasis on marketing strategy and customer experience/channel strategy work. In addition, she has led M&A strategy, post-merger integration, organization and operations restructuring projects. Prior to joining SECOR, Andrea was the VP, Membership and Advisory Services for the Canadian Business for Social Responsibility where she worked extensively on corporate social responsibility and sustainability issues.

NEIL PEET, CONSULTANT
npeet@secorgroup.com

Neil is a Consultant in SECOR's Toronto energy practice. He has focused on Scenario Planning and long-term strategic thinking, spending time developing scenario planning methodology across industries such as energy, natural resources, media and telecommunications, manufacturing, and retail to help companies reduce future uncertainties and develop responsive, but longer-term strategies. Prior to joining SECOR, Neil was the owner of RPM-Solutions, a web technology and IT consulting firm which helped companies develop technologies to move business processes online.

MONTREAL
555 René-Lévesque Blvd. West, 9th floor,
Montreal (Quebec) H2Z 1B1
Tel.: 514.861.9031
E-mail: info@secorgroup.com

NEW YORK
250 Park Avenue, 7th Floor
New York, NY 10177
Tel.: 212.307.0020
E-mail: info@secorgroup.com

PARIS
50/50 bis rue St-Ferdinand,
75017 Paris
Tel.: 01 56 26 57 27
E-mail: info@secorgroup.com

QUEBEC
2600 Laurier Blvd, Suite 955, 9th floor
Tour de la Cité - entrée 6
Quebec (Quebec) G1V 4W2
Tel.: 418.653.5335
info@secorgroup.com

TORONTO
390 Bay Street, Suite 2400
Toronto (Ontario) M5H 2Y2
Tel.: 416.362.0505
E-mail: info@secorgroup.com

VANCOUVER
World Trade Centre
Suite 550 - 999 Canada Place
Vancouver, BC V6C 3E1
Tel.: (604) 605-1123
info@secorgroup.com

SECOR