HEC MONTRÉAL
École affiliée à l'Université de Montréal

The Canadian Oil Sector under TIMES for Canada: Production, Consumption and Transportation

par
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Résumé

Cette thèse comporte trois papiers et un rapport qui contribuent à analyser l'avenir du secteur pétrolier canadien à l'aide d'outils quantitatifs. L'objectif principal est de comprendre les tendances et défis du secteur énergétique canadien, avec une attention spéciale au secteur pétrolier. Une approche de prévision sera utilisée pour développer un scénario tendance (*business as usual*). Une approche d'optimisation sera utilisée par l'application de modèles TIMES pour le Canada, afin d'analyser et de comprendre les tendances et défis du système énergétique canadien. Une attention particulière sera portée à analyser différents scénarios de transport du pétrole brut.

Le premier article, intitulé « *Future of the Canadian oil sector: Insights from a forecasting-planning approach* », concerne l'importance de fournir un bon cadre conceptuel pour traiter les décisions stratégiques liées à la production de pétrole et aux réserves de pétrole. Pour cela, on propose dans la présente thèse l'utilisation d'un modèle de prévision pour définir un profil de production dans le secteur pétrolier canadien à l'horizon 2030, en considérant des variables économiques et physiques.

Le deuxième article, intitulé « *A Canadian 2050 energy outlook: Analysis with the multi-regional model TIMES-Canada* », permet de comprendre comment le pétrole est utilisé, tout en rivalisant avec d'autres sources d'énergie, selon différents scénarios et les politiques mises en place par les gouvernements. Pour cela, nous utilisons le modèle TIMES-Canada, un modèle énergétique qui suit une approche dite montante (*bottom-up*) décrivant le secteur canadien de l'énergie.

Le troisième article, intitulé « *An analysis of the impacts of new oil pipelines projects on the Canadian energy sector with a TIMES model for Canada* », analyse différents scénarios d'exportation de pétrole brut basés sur les oléoducs existants, l'expansion prévue et le développement de nouveaux oléoducs. Pour l'analyse, on utilise également un modèle de type TIMES pour le Canada. Les résultats concernent en particulier les liens entre capacités d'exportation et niveaux de production pétrolière.

Le rapport développe un cadre conceptuel pour relier différents modèles et démontre son potentiel sur la dynamique canadienne d'offre et de demande du pétrole et sur les impacts de l'oléoduc TransCanada Énergie Est dans les provinces de l'Est. Ce cadre combine différentes approches de modélisation et les résultats analysent l'utilisation de l'oléoduc et sa contribution aux exportations internationales et à la consommation domestique. Les résultats montrent également l'impact de cet oléoduc sur les niveaux de production en mer. Les résultats illustrent bien le potentiel du cadre conceptuel développé.

En conclusion, tous ces chapitres se rejoignent pour présenter une approche de modélisation hybride qui combine les avantages des techniques de prévision et celles d'optimisation. Cette approche hybride contribue à la compréhension de l'industrie pétrolière au Canada qui joue un rôle majeur dans l'économie canadienne.

Mots clés : TIMES, pétrole, optimisation, planification, pipelines, prévision.

Méthodes de recherche : Analyses quantitatives.

Abstract

This thesis is composed of three papers and one report that contribute to analyze the future of the Canadian Oil sector with quantitative tools. The final objective is to understand the trends and challenges of the Canadian energy sector, with particular attention to the oil sector. A forecasting approach will be used to develop a "business as usual" scenario. An optimization approach will also be used by running TIMES models for Canada, to analyze and understand the trends and challenges of the Canadian energy system. A special attention will be given to analyse different scenarios of crude oil movements.

The first paper entitled "Future of the Canadian oil sector: Insights from a forecasting-planning approach", addresses the importance of providing a good framework to deal with the strategic decisions related to oil production and oil reserves. For this, it is proposed throughout this paper the use of a forecasting model to define a production profile of the Canadian oil sector, selecting a 2030 horizon that will allow us to consider economic and physical variables.

The second paper, entitled "A Canadian 2050 energy outlook: Analysis with the multi-regional model TIMES-Canada", allows to understand how oil is consumed, while competing with other energy sources, in different scenarios and under different policies designed by governments. For this, we use the TIMES-Canada model, a resource-constrained, bottom-up energy model describing the whole Canadian energy sector.

The third paper entitled "An analysis of the impacts of new oil pipeline projects on the Canadian energy sector with a TIMES model for Canada", analyzes different crude oil export scenarios based on existing pipelines, scheduled expansions and the development of new pipelines. For this analysis we also use a TIMES model for Canada. Results concern in particular the links between exporting capacity and oil production levels.

The report develops a soft-linking model framework and demonstrates its potential application on the domestic oil supply-demand dynamic in Canada and the impacts of the TransCanada Energy East pipeline in Eastern provinces. This framework combines different modeling techniques and the results analyze the pipeline utilization and its role in supplying both international exports and domestic uses. The results also show the impact of the pipelines on offshore production levels. The results illustrate well the potential of the proposed model framework.

In conclusion, all these chapters connect to present a hybrid planning model approach that combines the benefits of the forecasting and optimization techniques. The combined approach will help understand the oil industry in Canada that plays a major role in the Canadian economy.

Keywords: TIMES, oil, optimization, planning, pipelines, forecasting.

Research methods: Quantitative analyses.

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List of acronyms

AGR: agriculture demand sector

BAU: business as usual

CAC: criteria air contaminant

CAPP: Canadian Association of Petroleum Producers

CCS: carbon capture and sequestration

CEO: Canadian Energy Outlook

CERI: Canadian Energy Research Institute

CIMS: Canadian Integrated Modeling System

CNLOPB: Canada–Nova Scotia Offshore Petroleum Board

CNSOPB: Canada–Newfoundland and Labrador Offshore Petroleum Board

COM: commercial demand sector

CPI: Consumer Price Index

E3MC: the Energy, Emissions and Economy Model for Canada

EFOM: Energy Flow Optimization Model

EIA: U.S. Energy Information Administration

ESL: electron stimulated luminescence

ETP: Energy Technology Perspectives

GDP: gross domestic product

GHG: greenhouse gas

IEA: International Energy Agency

IEO: International Energy Outlook

IND: industrial demand sector

LNG: liquefied natural gas

LPG: liquefied petroleum gas

MAPLE-C: Model to Analyze Policies Linked to Energy in Canada

MARKAL: MARKet ALlocation model

NALEM: Newfoundland and Labrador Econometric Model

NATEM: North American TIMES energy model

NEB: National Energy Board

NEMS: National Energy Model System

NRTEE: National Round Table on the Environment and the Economy

OEE: Office of Energy Efficiency

OERD: Office of Energy Research and Development of Natural Resources Canada

OPEC: Organization of the Petroleum Exporting Countries

PADD: Petroleum Administration for Defense Districts

RES: Reference Energy System

ROW: rest of the world

ROWE: rest of the world east

ROWW: rest of the world west

RSD: residential demand sector

SAGD: steam assisted gravity drainage

TIAM: TIMES integrated assessment model

TIM: The Informetrica Model

TIMES: The Integrated MARKAL EFOM Systems

TRA: transportation demand sector

WCS: Western Canadian Select

WCSB: Western Canada Sedimentary Basin

WEM: World Energy Model

WEO: World Energy Outlook

WEPS+: World Energy Projections Plus

WNA: World Nuclear Association

WTI: West Texas Intermediate

To my grandparents, my lighthouse.

To my kids, Alan and Zoe, my reason to live.

To my parents, Petia and Eneida, for our love and their unconditional support.

To Gaby, my everything.

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The testing of the soft-link approach between the forecasting model and a TIMES model for Canada, focusing on the impact of the Energy East TransCanada pipeline in the oil and gas industry in Newfoundland and Labrador, was made possible with the financial support from Collaborative Applied Research in Economics (CARE) initiative at the Memorial University of Newfoundland.

I want to acknowledge the academic support, patience and guidance from Professor Olivier Bahn because without him, this thesis couldn’t have been possible. Olivier Bahn has been there all these years, reviewing the work, suggesting changes and advising with his vast knowledge of the energy sector and the modeling field.

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Also, the academic support and team work from Kathleen Vaillancourt who made the titanic task of developing, calibrating and running the TIMES models for Canada for all sectors in all Canadian regions.

I would like to thank Prof. Wade Locke for his insightful comments on the work related to the impact of the TransCanada Energy East pipeline in the oil and gas industry in Newfoundland and Labrador.

Preface

This dissertation is based on three articles and one report.

Chapter 1 is the first article with permission from the applicable sources. The presented model is an original contribution, covering all aspects of its development including: the theoretical framework, conceptualisation, testing and calibration of the model for the different regions and types of oil production in Canada. More specifically, I present a new and innovative model that positions itself between the gaps observed in the literature. The proposed methodology is a simple but effective way to obtain well count and to model how experts select the wells that they will drill in the future. Additionally, the implementation using aggregated logistic functions proves effective to model the decaying behaviour of oil producing wells. I was also the main author writing this article, doing the corrections and answering reviewer's comments.

Chapter 2, the second article, is the result of work from a large team. It is also used with permission from the applicable sources. The main contributions to this work are to the oil and gas sector and the demand drivers to run the model. More specifically, I did all the research related to the scenarios for oil, by developing the forecasting of oil production and oil price by type and region. These scenarios were directly connected to the forecasting model that I created in the first chapter of this thesis. I also participated on the research of some scenarios for gas. Of importance, is the development of a new methodology to forecast all the demand drivers by segment and region, considering all energy service sectors (agriculture, industrial, commercial, residential and transportation). I was the main researcher working on the oil extraction, refineries and oil transportation modules in this TIMES model. I also participated significantly on the runs of the model for the oil sector and its analysis. More specifically, my contribution was the update and development of the technologies represented in the Reference Energy System (RES) for refineries, fossil fuel reserves and oil energy trade. The implementation of the fossil fuel reserves required modifying these technologies in TIMES, to reflect the right evolution of oil production, according to the forecasting model. The implementation of the oil energy trade required performing structural changes on some of the corridors (pipeline and other means of transportation), with the design of the interconnection matrix in TIMES that will allow the supply meeting its final destination. My implementation of the refineries in TIMES required structural changes in the model to reflect the right yields for refined products. I provided and reviewed the information of the oil sector in the introduction of this article. I was fully involved on the runs to produce the numerical results for the evolution of the oil production curves in TIMES. I also provided the analysis of the 3 different oil scenarios in TIMES. Additionally, the discussion and conclusions of results comparing the different scenarios related to the oil sector, is also an important part of my contribution.

Chapter 3 is the third article used in the thesis. This is also a team work, used with the permission from the applicable sources. This article builds on the work presented in chapter 2, particularly in the work related to the oil sector where I was the main researcher. My contribution to this work is present in all its content. In the introduction, I provided and explained most of the information about the evolution of oil price, oil price differential, oil production and oil trade options by using information from several sources. Regarding the model, I helped expanding and updating it for oil exchange between provinces with the new information about the current and future projects for oil pipelines and developing the transportation matrix for oil pipelines and other means used in this TIMES model for Canada. I also contributed with the research of all scenarios for oil and the development of the methodology and forecast of all the scenarios of oil production and price by type and region. Additional contribution is the update to the forecasting of all the demand drivers by segment and region with the same methodology that I developed in chapter 2, but with new data. Of importance were the research and the analysis that I provided in the description of scenarios about the Canadian oil trade options looking to the base case of exporting to the USA markets, Asia, Eastern Canada and the rest of the world. I was directly involved in the description and design of scenarios, using the available information about current and future pipeline capacities in the baseline scenario and in the three alternate scenarios that we proposed to analyze the evolution of the Canadian oil sector and the Canadian energy system.

Chapter 4 is based on the report "Impact of the Energy East pipeline on the oil and gas industry in Newfoundland and Labrador" prepared in collaboration with ESMIA Consultants for the Collaborative Applied Research in Economics (CARE) initiative at Memorial University of Newfoundland. This research project is my original intellectual product, with the specific contribution to the design and proposition of the project. More specifically, I was the author behind the conceptualization of the project and the conceptual framework to link 3 different models: The crude oil production forecasting model, a TIMES model for Canada and the macroeconomic model developed and used by the provincial Government of Newfoundland and Labrador. More specifically, the main scientific contribution to the modeling and the quantitative methods fields lands on the creativity behind the soft-link. The development and successful implementation of the soft-link required a deep understanding of how each model works and how we can make use of the different externalities, to feed each model's inputs and to finally have a holistic approach. This also includes the understanding of the dynamics of each model that will allow the implementation of the iterative mechanism, to help with the stability of the final solution in the form of oil prices. I also contributed as the sole author to the calibrations and runs of the oil production forecasting model using oil price data from official sources, as well as the oil price information coming from the iterations from the TIMES model. Finally, another important contribution was to be the sole author behind the idea to move a TIMES model, from the usual long term environmental assessment, to a short term analysis looking into oil price dynamics. This implementation was challenging because of the difficulties behind the calibration of oil prices and its connection to the capacity constraints on the pipeline. Getting the marginal changes in price under the different scenarios and having reasonable results was also difficult. To our understanding, there isn't a similar research on the use of TIMES to analyse the oil sector. ESMIA consultants performed the runs and calibration related to their TIMES model.

General introduction

Canada is an important energy producer. It is the largest supplier of natural uranium, a leader in hydroelectricity production and an important producer/exporter of oil, gas and coal. The United States is the main consumer of Canadian energy products counting for about 98% of the total energy exports. This research work will place particular attention to the oil sector.

Oil and gas production in Canada has experienced a change toward the extraction from more non-conventional sources such as oil sands. At the provincial level, Alberta is by far the most significant oil producer, but the offshore production in Eastern Canada has been increasing significantly. Western oil sands are expected to represent the most important resources in Canada, in the coming years. The crude oil coming from bitumen will represent over 76% of this increase (CAPP, 2016). Although new technologies improve the actual life expectancy of conventional oil reserves, most of the growth in oil production levels for Canada is related to oil sands. All of Canada's bitumen resources can be found in Alberta and Saskatchewan. Canada owns the third-largest reserves of oil in the world, just after Venezuela and Saudi Arabia (NRCAN, 2016).

The availability of Canadian oil is uncertain and its accounting can vary from one year to another. This accounting difference also occurs between diverse reporting official sources. One reason for this variation is related to new technological and economic developments that are increasing the availability of cost-effective unconventional oil. The challenges related to oil sands developments include an important increase in energy consumption, greenhouse gas emissions and technology costs. For these reasons, there is an intrinsic marginal cost that is higher for oil sands than for conventional sources. Besides, we have seen how in 2015-2016, low oil prices challenge the economic flexibility of unconventional oil production in Canada.

These uncertainties and challenges for oil producers, translate into similar issues for planners, policymakers, forecasters, politicians and economists. It is important for all the stakeholders, to understand what to expect from the Canadian oil sector in the coming years. This understanding will allow them to do better planning and make savvier investments. The main objective of this work is to develop a new framework that will contribute to energy planning and give insights on the different trends of the Canadian energy system, with special attention to the oil sector. More specifically, we intent with this work to answer the following research question: What are the economic implications of the evolution of the Canadian oil sector?

Quantitative models can help with answering this question. This work is composed of three papers and one report that show the evolution toward the final framework that combines forecasting, linear programing and the use of macroeconomic information. This holistic approach is possible thanks to the use of a soft-link methodology that allows the integration, in one model, of economic and physical variables under a resource-constrained platform. This last characteristic is vital for decision making as it allows the evaluation of scenario analysis under marginal economics in the context of exploring possible futures under a prospective approach (and not a predictive one). These advantages, combined with the macroeconomic representation in the form of GDP and other demand drivers, creates the perfect environment to help decision makers do better planning and make savvier investments. The proposed methodological framework that evolves from its original form, the TIMES energy model, initially intended for energy and environmental policy analysis, creates a new group of possibilities. Considering all the supply chain, (oil supply, consumption, distribution, extraction, and refining) this new framework combines diverse and specific modeling approaches with a solid integration of economic and physical variables. It also allows taking the best of each world while combining them to improve the planning process and help with the investment decisions.

The first step for the development of this new framework is addressed in Chapter 1. This chapter describes a new forecasting modeling approach, its calibration and the results applied to the Canadian oil sector. The proposed model is my original contribution based on a new methodology. The most important contribution of this chapter is the combination of physical and economic variables such as oil production and oil prices. Based on the practices of the oil industry, the presented approach connects these two variables using infrastructure or well count as the linking component. The result is an interesting methodology that allows combining several factors required in the planning of the oil sector. The main contribution from this chapter is a robust approach to the forecasting of oil production and well count using oil prices as the exogenous data. This model also produces the additional advantage of calculating reserves with a robust framework linked to oil prices and economic development. Important benefits of this approach are derived because of the political and economic implications behind the oil reserves reporting and the proposed model offers an alternative that is based on market conditions. In resume, we present a new and innovative model that positions itself between the gaps observed in the literature. The proposed methodology simulates how the experts decide on the infrastructure that will be needed in the future. Additionally, the implementation using aggregated logistic functions is a good representation of the decaying behavior of oil producing wells. Note that, because of the initial scope for this work, we didn't consider technological innovation for oil drilling.

The proposed approach in Chapter 1 isn't enough to answer the initial questions. Let's consider the particular issue related to reserves and its use in modeling. With so many different reporting sources, which of all the reported reserves should we use? What kind of model is the most suited to deal with this uncertainty? Jakobsson, et al., in their paper "How reasonable are oil production scenarios from public agencies", (Jakobsson, et al, 2009), make an excellent argument for the defence of resource-constrained models. The issue with these models is the difficulty in the use of economic variables. Because of this, some authors support simple extrapolation of past data (Lynch, 2002 and Simon, 1996). The problem with simple extrapolation is that it can't catch all the dynamics that we see in oil production, cost, demand and reserves. More specifically, extrapolating declining production in exhausting oil fields doesn't explain the continuous reserves growth due to new discoveries. And extrapolating increasing production in new oil fields doesn't explain the future aging and the following decline in oil production. Even some of these extrapolation issues combined with the use of economic variables were addressed by Alcocer et al. (2016), the proposed model isn't enough to understand the extent of the impact for the Canadian economy. The main reason is because the proposed model addresses the initial questions in the context of forecasting and not under resource-constrained modeling. In order to understand the implications of the evolution of the Canadian oil sector and its impact on the Canadian economy, a different model is needed.

The oil industry plays a major role in the Canadian economy with over $69 billion of private investment in 2013 and generates over $18 billion for governments in taxes and revenues (CAPP, 2014a). In 2015, Canada's crude oil production reached about 3.9 million barrel/day (bbl/d), of which 61% was produced from oil sands (NEB, 2015). It is expected that by 2030, Canada will produce a total of 4.93 million bbl/d (CAPP, 2016). This possible scenario from official sources can change due to several factors such as interactions from other energy sources, constraints on oil production to reach other markets, environmental and energy policies by governments among other issues. This additional level of complexity, that is reasonable and should be in the mind of oil producers, planners, forecasters, politicians and economists, requires a resource-constrained model. For this reason, we propose the use of a TIMES models for Canada, a resource-constrained and bottom-up energy model describing the whole Canadian energy sector including interprovincial and international oil corridors.

Chapter 2 describes the TIMES-Canada model, its calibration and the different runs under several scenarios to evaluate possible paths for the Canadian energy system up to 2050. The main objective of this second approach is the introduction of a resource-constrained model that was missing in Chapter 1. My original contribution to this work is on the full research of all the data and scenarios for the oil sector. These scenarios are directly connected to the forecasting model that I developed in the first chapter. I also developed the new methodology to determine the demand drivers and the structural implementations of the different technologies related to the Canadian oil and gas sector in TIMES. More specifically, I implemented the oil corridors (pipelines and other means of transportation), with the design of the interconnection matrix in TIMES. I also designed the refineries, to reflect the right yields of refined products and the oil extraction technologies, to reflect the adequate production curves. I was also directly involved in the runs of TIMES for the oil sector and did most of the analysis of result and conclusions also related to the crude oil portion. From this paper the most important addition to the methodological framework is the implementation of a new multi-regional energy model for Canada that has been developed using the TIMES optimization model. The presented model describes in detail different aspects of the energy system such as the extraction, transformation, distribution, end-uses and trade of various energy forms and some materials. Technologies are also described in detail. The components are coupled through the Reference Energy System (RES), which establishes the network of energy flows and technological options around the energy system. Each demand sector is described by its economic and technological parameters. End-use demands are based on socio-economic assumptions and are specified exogenously considering different future scenarios. TIMES computes a dynamic inter-temporal partial equilibrium on integrated energy markets, from primary and secondary energy forms to energy services. More specifically, the objective function looks to maximize the net total surplus, equivalent to minimizing the total discounted system cost while respecting the constraints. The model assumes price elastic demands and a competitive market environment with perfect information and multiple agents. As a result of these assumptions, the market price of a commodity is equal to its marginal value. The main model outputs are future investments and activities of technologies at each period. An additional output of the model is the implicit price of each energy form, material and emission, which is equal to its opportunity cost (shadow price). The model tracks emissions of CO_2, CH_4, and N_2O from fuel combustion and processes. Note that in this thesis we did not consider any GHG limitation imposed for the energy sector, but obviously, TIMES models are also well equipped to address climate policies.

As we can see, the approach used in the second chapter is broad and allows the understanding of a vast number of considerations related to the oil sector, including its interaction with other energy sources and some of the implications to the Canadian economy. The insights and issues for Canada that are related to the energy balance between 2007 and 2050, considering different scenarios, could be found with this approach. More specifically, we define and analyze possible futures for the Canadian integrated energy system on a 2050 horizon, under different baselines. In our Reference scenario, we show that the Canadian final energy consumption is expected to increase. In all scenarios, oil products will continue to dominate in the long term, although in a decreasing proportion over time in favor of electricity and biomass/biofuels. Regarding the corresponding optimal energy production paths, we illustrate two main trends: a gradual replacement of onshore conventional oil & gas sources by unconventional and offshore sources and a significant penetration of renewables in the electricity mix. The development and calibration of such detailed technology-rich model represents an important contribution to Canada. This TIMES model for Canada is an optimization model that covers in details the large diversity of the provincial energy systems considering a long-term horizon.

Even the important contribution of Chapter 2, the proposed analysis requires a deeper study to understand the implications related to oil trade and how the expected oil production will be consumed by the demand. Considering only Canada for all the expected oil production from the Western provinces doesn't seem enough. To achieve the forecasted production levels, producers of Western Canadian oil must find a market that values their oil at reasonable prices. Alberta and Saskatchewan need to develop their transportation capacity to export this expected production. The challenge related to the increasing availability of Western Canadian oil and its distribution to domestic and international markets is imminent. Indeed, uncertainty in oil reserves and production implies uncertainty on future trade movements and consequently, in oil corridors. As for their actual markets, maintenance of existing pipelines and the necessity of upgrading refineries to process this crude oil from Western Canada create bottlenecks that increase the constraints to allow the expected growth.

All these challenges have economic implications that translate in a price differential. The oil production surplus and the inability to reach external markets have already negative effects on the oil prices for Western Canadian producers. As a reference, one may consider the price differential between benchmark crudes West Texas Intermediate (WTI) and Western Canadian Selected (WCS). From 2007 to 2010 the WCS, that is the reference for Canadian heavy crude, traded US$16.64/bbl below WTI (NEB, 2013). This gap in prices augmented to US$19/bbl between 2011 and 2012, showing high volatility: up to US$30/bbl difference for some monthly averages. The highest spread was registered in December 2013 with US$38.94/bbl difference (Alberta, 2016). This price differential is used to reflect the supply-demand imbalance, the difference in the transportation costs and quality between the two products. According to all projections (NEB, 2013; CAPP, 2014b; NEB, 2016), it is expected that production will soon exceed current pipeline capacity and only long-term solutions may help to support this projected growth. In the short term, transportation by rail cars is providing a temporary solution. However, the incremental capacity to export via rail cars will not be sufficient in the long term. In summary, it is necessary for Western Canada to find and open new markets to enable a significant increase in oil production. There are three main markets for Western Canada oil production: 1) Central and South USA markets, 2) Canadian and USA West coasts and Asia, and 3) East Canada and Eastern USA. Indeed, Western producers are considering new markets on the other side of the country. Refineries in Québec and the Atlantic Provinces import more than 80% of their crude oil (642,000 bbl/d) from international markets. Supplying East refineries with Western crude will contribute to the country's energy security. Eastern refineries can start using synthetic oil or handling blends containing a portion of heavier crude without much modification to their installation. There is the additional advantage of an existing, but incomplete, network of pipelines that could be used to transport large amounts of crude to these regions. The first phase of the Enbridge Line 9 reversal is facilitating this internal transportation. PADD I district is also a potential market. Two pipeline projects are key to open these new markets, the Enbridge Line 9 A and B reversal, and the TransCanada Energy East Pipeline. If they were to be accepted in their actual form, they would add respectively 300,000 bbl/d and 1 million bbl/d to Québec's and Atlantic refineries. This research work will focus on trade between Western and Eastern Canada.

As we can see, adding trading to the analysis alters significantly the economic component of the equation. Because of this, new uncertainties and challenges are added to the already complex environment dealt by oil producers, planners, policymakers, forecasters and economists. The understanding of the impact of new pipeline developments for oil producers locally and in other regions and the understanding of the economic benefit to the whole energy system and to Canada are examples of these new challenges. It is important for all the stakeholders to understand the cost and benefits of the integration between different regions.

Chapter 3 looks into the details of the impact of new pipeline projects to the Canadian energy sector using a TIMES model for Canada. The main objective of this chapter is to show applied results, focusing on a more detailed implementation in TIMES to represent the oil pipeline transportation system. This chapter builds on the work presented in Chapter 2, particularly in the work related to the oil sector where I was the main researcher. My original contribution to this work was the data collection, determination of the demand drivers and structural implementations of the oil transportation system in TIMES, using the new available information about the current and future projects for oil pipelines. I explain the evolution of oil price, oil price differential, oil production and oil trade options in this chapter's introduction. I was directly involved in the research and analysis of scenarios about the Canadian oil trade options, looking to the exports to the USA markets, Asia, Eastern Canada and the rest of the world. My contribution to the baseline scenario and the three alternate scenarios about the evolution of the Canadian oil sector and the Canadian energy system was significant. More specifically, I verified that the evolution of oil production curves was consistent across all different scenarios in the results section. I also provided most of the analysis, discussion and conclusions about the results related to oil trade, oil production profile and oil price evolution. From this paper, the most important addition to the methodological framework is the detailed development of the pipeline scenarios into a TIMES model for Canada. We have compared the impacts of the crude oil production profiles and final energy consumption mix under the different maximum levels of conventional and unconventional oil exports. Regarding the insights and issues for Canada, the results show that exporting capacity will become an important driver for oil production level in the country. Outside the oil sector, impacts on the energy system are limited. In particular, final energy consumption patterns are similar across scenarios since fossil fuels remain the basis for the economy, regarding the origin of crude oil.

All the insight and modeling goals obtained in Chapter 3 are relevant and answer several questions to understand the economic implications of the oil sector in the Canadian economy. But our work wasn't complete because the resource-constrained approach from TIMES doesn't close the loop if we consider reserves and oil prices. This is because reserves in TIMES are exogenous data to the model, the same as oil prices. In order to improve our analysis and close the loop with the missing components in Chapter 1 and Chapter 3, we need to propose a different approach that takes the best from both worlds. This is why we need to extend the functionality of the TIMES model by creating a "soft-link" with the well count forecasting model to provide useful inputs on reserves, economic variables and short-term focus. This approach will allow us to get the best of both, forecasting and optimization. From the forecasting approach, we get the connection between price, quantity and infrastructure and the short-term insight to shape the business as usual case and the reserves, connected to economic variables. These benefits are important if we want to implement corporate analysis and short-term impact of strategic decisions. Additionally, we also get an approach that provides a more robust methodology to use reserves looking into economic conditions. From optimization, we get the connection between supply and demand, using a resource-constrained model and having more flexibility to handle different scenarios related to economic development. We also get the tools from optimization such as shadow price and reduced costs that are great to analyze competitive sources and strategic decisions.

Chapter 4 implements the soft-link framework using the models that are proposed to assess the impact of the pipeline trading in the oil supply-demand balance for Eastern Canada. The implementation looks into the dynamics resulting from different economic growth scenarios and different pipeline capacity scenarios, related to the supply of Western Canadian oil to Eastern provinces. The main objective of this chapter is a full-scale implementation of the proposed framework that includes forecasting, optimization and the use of macroeconomic data. The obtained results look to understand the particular problem derived from the oil trades, due to the development of the TransCanada pipeline and its impact to the oil production and price for Eastern Canada. My original contribution to this work was the development of an innovative methodology, based on a new framework that links three different models and the application of this framework to solve a particular problem. I explain this approach in the executive summary and the methodology section of this chapter. More specifically, my main scientific contribution is the development and successful implementation of the soft-link. This required deep understanding of how each model works and how we can make use of the different externalities to create a holistic approach. It also required a good understanding of the dynamics of each model, to allow the implementation of the iterative mechanism that will help with the stability of the final solution in the form of oil prices. Another important contribution is to move the TIMES model implementation from the usual long term environmental assessment, to a short term analysis looking into oil price dynamics. This implementation was challenging because of the difficulties behind the calibration of oil prices and its connection to the capacity constraints on the pipeline. Getting the marginal changes in price under the different scenarios and having reasonable results was also an interesting process. To our understanding, there isn't a similar research on the use of TIMES. In the introduction of this chapter, I explain the context about the evolution of oil price, oil production and trade issues related to oil pipeline capacity. Then, in the Methodology section, I explain the methodological framework and the forecasting model, with some contribution to the TIMES RES from my previous work in Chapters 2 and 3. I had important contributions in the scenarios section for this chapter where I participated in defining the scenarios and running my methodology to forecast demand drivers in TIMES, originally developed for the work in Chapter 2. Finally, I participated verifying, analyzing and concluding about the results, looking to the details related to oil prices, oil production profiles and oil trade. Insight for Canada suggests that the pipeline would be used at its maximum capacity starting around 2030 for both international exports and domestic uses in Eastern refineries, representing up to 98% of the crude used in Newfoundland and Labrador. By blocking the access to WCSB oil in Newfoundland and Labrador, this scenario brings the offshore oil price up by 10$/bbl in 2035 and 4$/bbl in 2050. The results of the forecasting model show higher production levels between 5% and 14% on average for the 2013-2050 period using these oil prices compared with those of the National Energy Board. The results illustrate well the potential of the model framework to analyse such supply-demand dynamics using a combined modeling approach.

The development of this thesis has taken several years, testing different approaches and finding the final framework that seems very promising as a new methodology to analyse the economic implications of the evolution of the Canadian oil sector. As we can see, the Canadian oil sector is quite complex and there are important challenges to overcome in the following years. In order to analyze the challenges faced by the Canadian oil sector and the different possible outcomes, according to the development of different scenarios, this thesis is proposing a quantitative approach that combines three models via “soft-link” for such analysis.

This thesis is as follows: Chapter 1 is used to describe the forecasting approach. Chapter 2 describes the TIMES-Canada model. In Chapter 3, we’ll describe the pipeline trade scenarios in a TIMES model for Canada. Chapter 4 is the last quantitative research work and is used to describe the soft-link including a forecasting model and a TIMES model for Canada, taking the advantage of the combined modeling approach for trading between Western and Eastern Canada. Finally, we conclude on the main outcomes of the study.

Chapter 1
Future of the Canadian oil sector: Insights from a forecasting-planning approach.

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Abstract

It is increasingly important to provide the relevant data for strategic decisions related to oil production and the marketing of oil products. We propose the use of a forecasting model to define a production profile for the Canadian oil sector to 2050. Our approach considers both economic variables (prices) and physical variables (production and infrastructure) by establishing a link between well count, oil price, and oil production. Our methodology is based on practices developed in the oil industry. Indeed, the well count is used as a key component of planning and decision-making in matters such as capital and operational expenditures. We combine our approach with the Hubbert logistic function to take into account the impact of the age of the producing wells. We calibrate our forecasting model using a Canadian database of historical production data. The records come from Eastern Canada offshore and Canadian oil sands projects that are of growing importance in the national oil production. We test our model under a particular scenario for oil prices, including an extrapolation of the historical price trends. Our results show the evolution of oil production and indicate when peak production is achieved for each of the oil sources considered.

Keywords: Forecasting, Hubbert, Well Count, Oil production, Oil prices, Oil reserves, Oil sands, Onshore, Offshore, Infrastructure.

1.1 Introduction

Given the complexity of oil markets, there is an ongoing need to create more accurate and reliable models to explain and predict evolution in oil production, regulations, and prices. The models are necessarily simplified representations that aim to reflect real-world tendencies.

The estimation and forecasting of recoverable oil is difficult because reserves can vary from one year (and one source) to the next depending on technological, economic, and political considerations. Technological improvements reduce costs and increase access to resources that were not available before. Likewise, a better economic environment stimulates the energy demand, yielding higher oil prices that make more expensive projects profitable. The combination of technological improvements and high oil prices, with oil prices averaging USD 100/bbl between 2011 to part of 2014, motivated the growth of US crude oil production from 5 mb/d in 2008 to 9.4 mb/d in 2015 (IEA, 2016). This important increase of new oil, combined with the decision of the Organization of Petroleum Exporting Countries (OPEC) to maintain and expand their market share and the increase in Iran's oil exports after the lifting of sanctions, resulted in an excess of supply with the consequent contraction of price. This new scenario is producing major reductions in oil investments, placing expansions on hold and re-evaluating many projects. More pressure will be added as key developing countries are increasing efforts to improve energy efficiency (IEA, 2016).

Reserve data are also important for governments and companies because this information gives access to production quotas, as in the OPEC case, or to financing resources because the value of the fields is related to the reserves. BP reports illustrate the reserve data with variations in different years: (BP, 2006) assesses Canadian proved reserves for 2006 at 17.1 million barrels per day (MMbpd), while (BP, 2010) assesses the value of the same year at 27.6 MMbpd, with a further increase to 32.1 MMbpd for 2010. Currently, Canadian proved reserves are at 172.9 MMbpd for the year 2014 (BP, 2015).

Note that the economic and technological dimensions of the reserves are easier to model than the political dimension. In particular, the technological aspect can be modelled using the cumulative stock (Holland, 2008), and the economic aspect is related to the concept of the supply curve (Besanko and Braeutigam, 2011).

This article considers in particular unconventional oil and offshore production. The former category consists of extra-heavy crude oil, oil sands, oil shale. These unconventional oil sources are more labour-intensive to produce, require extra energy to refine, have higher production costs, and are often in remote locations. Additionally, they present other problems such as higher greenhouse gas (GHG) emissions (up to three times more GHG emissions per barrel than conventional sources (Arsenault, 2008; Charpentier, Bergerson, and MacLean, 2009)), waste management issues, and water usage issues. This article also considers offshore production, which is mostly light oil, because of its recent growth and the challenges associated with such technological development. The exploitation is more complex because of the remote locations. Additionally, offshore developments present a risk of ecological disasters, such as the one that occurred in the Gulf of Mexico in 2010. All these factors have contributed to the postponement of unconventional oil exploitation. However, the transformation experienced by oil markets has permitted the development of these expensive resources. Three of the key unconventional sources for large-scale production are the extra-heavy oil in the Orinoco Belt of Venezuela, the oil sands in the Western Canada Sedimentary Basin (WCSB), and the oil shale of the Green River Formation in Colorado, Utah, and Wyoming in the United States. Another important unconventional source is the light-tight oil. Formations of this resource include the Bakken Shale, the Niobrara Formation, Barnett Shale, and the Eagle Ford Shale in the United States.

Canada is an important energy producer, in the fifth position globally; with the United States as the main consumer of Canadian energy products (BP, 2015). In 2014 Canadian oil production was led by Alberta, which produced approximately 42% of the total, while Eastern Offshore production represented approximately 15% (Canadian Association of Petroleum Producers (CAPP), 2015). Over the last 15 years, Alberta's production share has decreased by 16%, while Eastern Offshore production increased by 8% between 1999 and 2014 (CAPP, 2015). Despite these changes, Western Canada (British Columbia, Alberta, Saskatchewan, and Manitoba) continues to lead oil production with a share of approximately 85% (CAPP, 2015). In parallel, there has been a decrease in the share of conventional oil: conventional production accounted for 72% of the total in 1999, and 42% in 2014 (a decrease of approximately 30%) (CAPP, 2015). Thus, the decline in the percentage of conventional energy sources runs parallel with an increase in unconventional sources. In particular, oil sands production has experienced significant growth, rising from 28% of the total in 1999 to 58% in 2014 (CAPP, 2015). Considering the oil production by province and by source reveals an interesting new trend for Canada's oil production. The leading new developments in the last fifteen years are the Western oil sands (with an increase of 30%) and the Eastern offshore (with an increase of 8%). To summarize, as conventional oil production declines, there is a corresponding increase in crude oil produced from oil sands and offshore developments. What about the future? More precisely, what changes can be expected in the future in the Canadian oil sector and the evolution of conventional and unconventional sources?

To address this question, we combine two approaches. First, we use a forecasting approach based on the correlation of oil production and price to predict the annual well count (i.e., the new wells drilled each year). Second, we use the logistic function of the Hubbert approach (Hubbert, 1956) to empirically explain the decay in oil production. The Hubbert curve improves the forecasting approach by taking into account the depletion characteristic of oil resources according to their installed capacity. In addition, the forecasting approach complements the Hubbert approach by accounting for the necessary investment. The overall approach corresponds to a combination of physical and economic variables in an original model that allows us to analyze the evolution of the Canadian oil sector and its economic implications under different scenarios. The utility of the proposed oil forecasting model is to provide inputs in the form of different scenarios that can be used within larger models (e.g., a TIMES model representing the entire energy system) to yield more accurate energy analyses.

Traditional forecasting models use past data to determine historical trends that predict future behaviour. These models are commonly used to create a "business as usual" (BAU) scenario. Brandt (2010) describes several approaches to forecasting oil production: Hubbert's logistic model (Hubbert, 1956), the system simulation model (Sterman and

Richardson, 1985), bottom-up models (Bentley and Boyle, 2007), and economic models (Hotelling, 1931; Nordhaus, 1973; Kaufmann and Cleveland, 2001; Holland, 2008; Jakobsson et al., 2012; Jakobsson et al., 2014; Apergis et al., 2016). We will describe the economic models in more detail. Hotelling (1931) asserts that if there is an optimal and efficient extraction path over time, the value of the non-renewable resource must be rising at the interest rate. In other words, the (discounted) shadow price of the resource stock, which can be considered as an economic measure of the resource scarcity, should grow at the interest rate. Nordhaus (1973) focuses on the whole energy market and looks for the minimum discounted costs to meet demand, assuming competitive suppliers operating in a competitive market. Kaufmann and Cleveland (2001) apply the Hubbert model to predict oil production using differences between the predicted and actual values as input for the calibration of an econometric model with economic and policy variables. Alternatively, Holland (2008) presents four Hotelling-style models evaluating different situations such as demand shift and technological change while analyzing peaks in oil production. Jakobsson et al. (2012) proposes a bottom-up approach to calculate production from a single oil reservoir, considering investment in platform capacity addition and the drilling of wells, allowing modelling the plateau level and the decline rate in oil production as a result of economic optimization. The resulting model reconciles production with geological, physical and economic factors. Arpegis et al. (2016) uses time series econometric techniques to examine the relationship between oil production, rig count, and crude oil prices of six U.S. oil-producing regions. In his survey of bottom-up approaches, Jakobsson et al. (2014) reviews models that describe the oil supply chain, with focus on the economic and geologic issues that are the most relevant in modelling. The main conclusions are that the high level of detail in bottom-up models is of questionable value for predictive accuracy, but of great value for identifying areas of uncertainty and make use of sensitivity analysis. Of particular interest was the presentation of the EIA-OLOGSS model, where production is modelled at the well level and the number of wells in a project is a consequence of economic considerations.

Most of the presented approaches do not deal with the combined problem of pricing, production, and infrastructure. Only Jakobsson et. al. (2012), the models reviewed in Jakobsson et al. (2014) and Arpegis et al. (2016) address this combined problem. The model presented by Jakobsson et al. (2012) is detailed at the technical level and uses endogenous pricing. It is not clear for us how to extend its use to interface with larger models that allow the interaction between different energy sources and other regions. Arpegis et al. (2016) results are good for short-term foresight and interesting regarding the conclusions between correlation and causality of the combined problem. On the other side, they don't provide a good representation of the combined problem dynamics for medium and long term, because they don't use depletion curves to represent the evolution of oil production. From the review presented by Jakobsson et al. (2014), EIA-OLOGSS is the only model that uses the number of wells as cost driver. It also uses exogenous inputs and allows the interaction with a larger model, the NEMS (National Energy Modeling System). The model is under the custody of the EIA and is very detailed at the technical and economic level. On the other side, it is not of easy access and it is a complex model.

In this article, we combined pricing, production and infrastructure in a simple but effective way, by developing a bottom-up model based on well count (or production assets), where this count represents the main connector between oil production and oil price. We estimate the parameters via linear regression. Our model allows us to explain well-count evolution according to oil production and oil price, under the assumption that there is a linear relationship between the dependent variable (well count) and the independent variables (production and price). In order to follow this assumption, let's consider the rationale for the strategic decisions between producers and consumers. In a perfect competitive market both participants look to maximize the total net surplus. This is achieved by minimizing the net total cost and maximizing the total net profits. Minimizing costs for producers is related to well investment costs and for consumers is related to oil prices. Maximizing profits for both, consumers and producers is related to the amount of oil production. In this work we assume that new investments follow the rationale of an upward relationship between oil price and production at a specific time (Besanko and Braeutigam R, 2011).

We apply a Hubbert logistic model looking at the most basic level of oil production (i.e., the well count). Our approach differs from other multi-cycle Hubbert logistic models, which usually consider the field level, looking at two or three cycles. Cycles are changes in the parameters due to new production or discovery conditions. For example, cycles in production relate to conventional production versus enhanced oil recovery, and cycles in discovery relate to the type of field such as oil sands, shale oil, or deepwater exploration (Laherrère, 2000). In our case, although we are not explicitly dealing with a multi-cycle approach, we are implicitly considering cycles through investments. Furthermore, we are able to simulate the maturity of a field by modifying the production level of each year's well count according to the age of the field.

We apply our approach to the Canadian oil sector. More precisely, we generate numerical results for a BAU development of the Canadian oil sector. We analyze the results and compare them to predictions from different sources (Söderbergh, Robelius, and Aleklett, 2005; National Energy Board of Canada (NEB), 2007, 2013; CAPP, 2009).

The remainder of this paper is organized as follows. In Section 2, we present our model and describe how it is calibrated. Section 3 discusses our numerical results, and Section 4 provides concluding remarks.

1.2 Modeling approach

Our model aims to guide oil production planning using a forecast that links well count, oil price, and oil production. More precisely, we first use a forecast based on a linear regression model to predict the well count. We then consider the decay in oil production using a Hubbert logistic curve. This enables us to predict the oil production and well count under different oil-price scenarios.

For a company exploiting an oil field, a well is the basic production unit. Called a "producing asset", its production decreases over time as the corresponding non-renewable resource is exploited. In a given oil field, the initial production of an individual well is determined by the oil field's age. Specifically, in a new oil field, the production rate per well will initially increase when a new well is drilled. Conversely, in a mature oil field, the production rate per well will decrease when a new well is drilled.

1.2.1 Model

We assume that yearly production of oil ($P_{o,n}$ in barrels per day) of a given oil type *o* (e.g., onshore, offshore, or oil sands) in a given field or region *n* is a linear function of the new investments ($I_{o,n}$) that correspond to the number of newly drilled wells (the well count; no units), the field average production rate per well ($f_{o,n}$; no units), the time-indexed performance (production) for individual wells ($w_{o,n}$; in barrels per day) assumed to be identical for the new wells drilled in a given year (as a vintage), and the average life ($l_{o,n}$; in years) of the assets (wells), as follows:

$$P_{o,n}(t) = \sum_{i=t-l_{o,n}}^{t} \Big(I_{o,n}(i).f_{o,n}(i).w_{o,n}(t-i)\Big) \qquad (1)$$

where *t* is a (discrete) time index corresponding to the year considered. Note that the field average production rate ($f_{o,n}$) could be either a constant (average production) or a function of time for the quantity produced. In the latter case, it could account for learning effects (improving with time or as more oil is produced). It can also represent the maturity of the oil field.

Let us now detail the investment in new wells ($I_{o,n}$). Under some (strong) microeconomic assumptions (Jukić, Scitovski, and Sabo, 2005) that define a perfect competitive market (such as perfect information, a large number of buyers and sellers, free entry and exit, homogeneous goods, perfect factor mobility, and zero transaction costs), one can postulate an upward relationship between oil price (*p*) in US dollars and the production ($P_{o,n}$) in barrels per day at time *t*. We assume here that the new investments follow this rationale as described below:

$$I_{o,n}(t) = k_o + k_1.p(t) + k_2.P_{o,n}(t) \qquad (2)$$

where k_0 (no units), k_1 (1 / US dollars), and k_2 (1 / barrels per day) are calibration parameters.

If it is true that the Canadian oil industry isn't perfectly competitive, the use of Eq. (2) is justified because of the microeconomic rationale that an increase in oil prices is an incentive to produce more. Let's consider the price of Canadian oil from Alberta. Its price is disconnected from international markets because it is locked in Alberta and there is more supply than the oil that can be physically moved to the final demand. But on the other side we have seen the rationale behind new pipeline developments and how oil prices from Alberta have been catching up to international markets as more oil is railed and pipelined to East Canada and the Gulf Coast.

Equations (1) and (2) are based on a supplier behaviour according to specific microeconomic principles as well as practices in the oil industry. More precisely, oil-producing firms typically use an approach similar to Eq. (2) as a planning tool to help them decide what new wells to drill. In this case, the price and production levels (to be used in Eq. (2)) are based on expert estimations. We have statistically tested the correlation between oil prices and well counts for Canada; see Section 1.3.

We now discuss the performance of individual wells ($w_{o,n}$). To predict the future oil production, we use the Hubert peak approach that uses a logistic function to explain the decline in the production of oil wells and fields over time (Hubbert, 1956). This function is based on empirical observations made by the American geophysicist M. King Hubbert as he successfully predicted the evolution of American oil production around 1965–1970. It can be expressed as follows:

$$w_{o,n}(t) = \frac{h0 \cdot e^{-h1 \cdot t}}{\left(1+ \ \cdot e^{-h1 \cdot t}\right)^2} \quad (3)$$

where h_0 is the maximum production that one individual oil well can achieve and h_1 is a factor describing the rate of oil production decline over time. These two parameters are adjusted to match the total production for a specific oil type and region.

The next section details how we calibrate our model for Canadian oil production.

1.2.2 Calibration

1.2.2.1 Calibration procedure

We have calibrated our model for the different types of oil production (conventional onshore, offshore, and oil sands) for two regions (Eastern and Western Canada) for the period 1980–2007. The calibration procedure takes two steps. First, parameters k from

Eq. (2) and h from Eq. (3) are estimated to match the historical well-count levels using estimations of price and production. However, this calibration does not exactly match the historical production level. A second iteration is necessary, to produce new estimates for the parameters k that will be used only to forecast production levels (and reserve levels, as discussed in Section 1.3.3).

Step 1 (parameter calibration for well-count estimation):

Parameters k_0, k_1, and k_2 from Eq. (2) are estimated using a multiple linear regression. The prices (p) are the average annual market prices of West Texas Intermediate (WTI) (U.S. Energy Information Administration (EIA), 2011). Note that until 2007 WTI was routinely used as an oil-price reference for North America. The production levels ($P_{o,n}$) are chronological values for the total oil production for the specific type and region considered (CAPP, 2009). The investment values are chronological values for newly drilled wells (CAPP, 2009; BP, 2010). The values $f_{o,n}$ are available for the period 1980–2007 for which the calibration is performed (CAPP, 2009; BP, 2010). The parameters h_0 and h_1 from Eq. (3) are estimated via a multiple nonlinear regression on Eq. (1). More specifically, we have the number of new wells ($I_{o,n}(i)$) and the total production ($P_{o,n}(t)$) from previous years. $f_{o,n}(i)$ is also known (it was set equal to 1) so we need to determine h_0 and h_1 as the only unknown parameters by substituting all the information from previous years in Eq. (1).

When we use the above estimates for k and h to compute (following Eq. (1)) the predicted production levels, we find that the levels do not exactly match the observed historical values. Indeed, oil firms do not base their future investment decisions on prices and production levels (that cannot be observed) but on an expert estimation of these values. Hence, Eqs. (1) and (2) cannot precisely reproduce past investment decisions. To overcome this difficulty, we propose a second calibration for the parameters k to be used only when forecasting oil-production levels.

Step 2 (revised calibration for oil-production estimation):

Let k_i^1 be the parameter estimate from step 1, and let $I_{o,n}^1$ and $P_{o,n}^1$ be the values of the well count and production computed using this estimate. Similarly, let k_i^2 be the parameter estimate to be obtained during step 2, and let $I_{o,n}^2$ and $P_{o,n}^2$ be the values to be computed using the new estimate. Let $\overline{P_{o,n}}$ be the observed historical values for the calibration period (1980–2007).

To calibrate $P_{o,n}^2$, we use a weighted least squares approach (Kiers H.A.L., 1997). The idea is to minimize the (weighted) error between the observed production ($\overline{P_{o,n}}$) and the predicted production ($P_{o,n}^2$) while keeping the new predicted well count ($I_{o,n}^2$) close to the count ($I_{o,n}^1$) calibrated in step 1.

1.2.2.2 Calibration results

As an illustration, we present the results of our calibration for the Canadian onshore oil production, for which long-term historical data are available (CAPP, 2009). Onshore oil fields are mature, so the production rates are decreasing over time. Figure 1 presents the estimated well count versus the actual count, together with the 95% confidence interval curves.

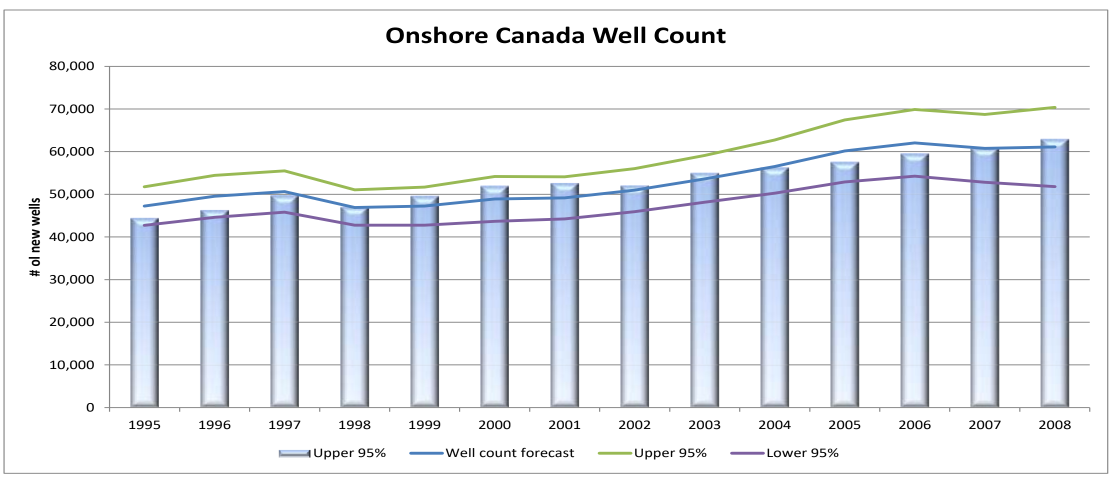

Figure 1. Comparison of the estimated and actual well count (actual data from CAPP (2009)).

Figure 1 reveals that there is a good agreement between the estimated and actual values. We have also verified that the results are statistically significant by performing a series of tests. The P-values are around 10^{-6} for production and 10^{-8} for price. The adjusted R-square is 0.91 (R-square is 0.998), indicating a strong linear correlation between our dependent variable (well count) and the independent variables (WTI and oil production).

Figure 2 shows the contribution of each input variable (production and price) to the well count, resulting from the linear regression performed in Step 1 of the calibration.

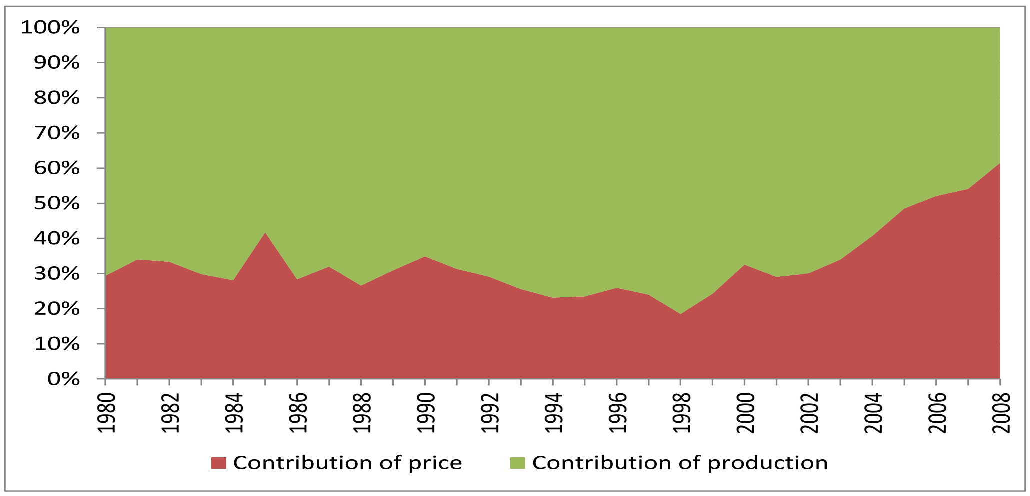

Figure 2. Contribution of each input to well count.

As expected, Fig. 2 reveals that production is the main driver of well count, but as the price increases, its contribution becomes more significant. A possible explanation for this is that higher prices may fuel speculation. This would be similar to the behaviour observed in the stock market, where traders show a positive feedback for future purchases in response to today's price increase (De Long, Shleifer, Summers and Waldmann, 1990). The two calibration steps intent to simulate the decision-making process for the investments, where the first step is based on expected market values and the second is linked to real production values.

The decision-making process for investments in the oil sector requires understanding the fundamentals behind this product. Oil has a significant impact on each country's economic development. Oil prices are determined through a complex process that involves several types of economic agents: oil analysts, oil suppliers, oil consumers (mostly represented by refineries) and speculators.

Oil production itself is a complex process involving different technologies, according to differences in geographical areas and production sites (onshore, offshore deep water, ultra-deep water, fracking, mining). Oil production requires high investments associated with high-risk returns. The resulting oil production derives on several different qualities of oil which requires different refinery configurations with important capital investments associated with high-risk returns.

The use of economic and physical variables contributes to improve forecasting in a multi-linear regression analysis, where the dependent variable (investments) has a significant uncorrelated contribution from each dependent variable (oil production and price). In other words, production and price contain enough information to help the decision maker to determine investments and mitigate risks.

Regarding its relevance, production is the main driver for investments, but as the price increases, its contribution becomes more significant. Looking to the simulation of the decision-making process, the decision maker has to weigh between the risk expressed in the volatility of oil prices and the real physical need to match the balance between oil supply and demand. Long-term investments require 5 years development, and today's decisions aim to target the balance between supply and demand after those 5 years. Higher profits will depend on how closer the prediction was to the final balance.

To estimate the field average production rate per well ($f_{o,n}$), we divide the total annual production by the well count and perform a linear regression. Figure 3 illustrates this linear fit for Canadian onshore production.

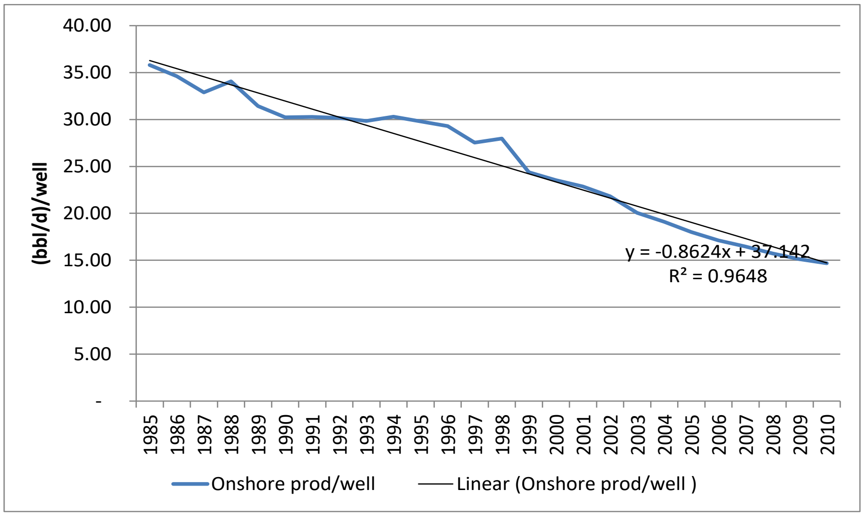

Figure 3. Linear trend for unitary well production in onshore Canada (actual data from CAPP (2009)).

As expected, Fig. 3 reveals that the oil production for each new well decreases since the oil field is depleting. Such a linear fit is appropriate for a mature oil field. In the case of a new field (oil sands) we have adjusted the linear trend to capture the change from an increasing to a decreasing rate. A more sophisticated approach would be to use a Hubbert logistic function to capture this change.

Figure 4 presents the final fit for the onshore oil production after the second calibration step. In this figure, the actual production data come from the CAPP report (2009).

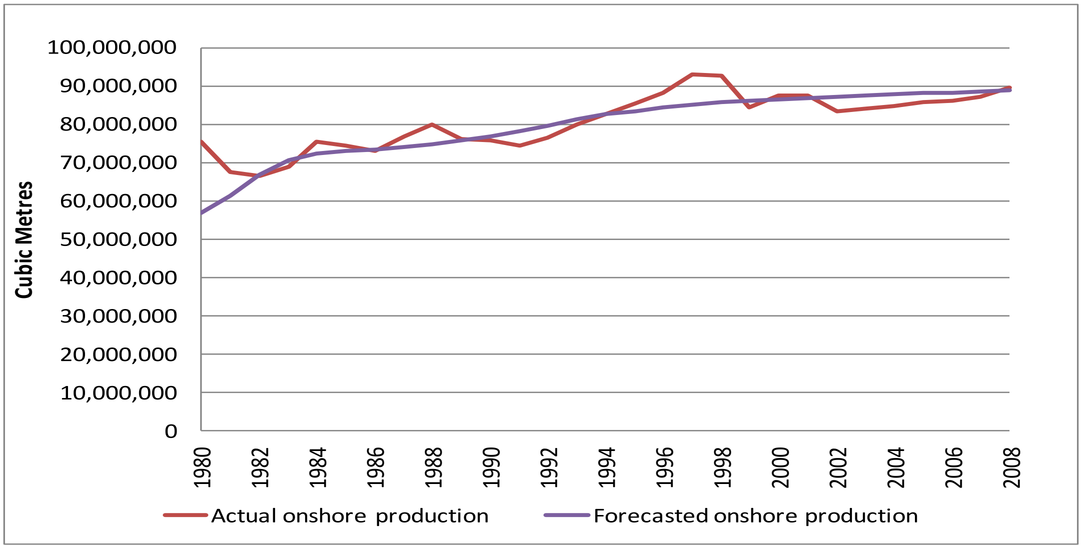

Figure 4. Results from the curve fitting model (actual data from CAPP (2009)).

Figure 4 shows a good agreement between the estimated and actual onshore production. Additionally, various tests show that the results are statistically significant. The P-values are around 10^{-36}. The adjusted R-square is 0.96, indicating a strong linear correlation between the forecast and observed production.

1.3 Numerical results

In this section, we apply our methodology to forecast the Canadian offshore and oil sands production for newer oil fields (CAPP, 2009). The production rates initially increase over time and then start to decrease as the fields become mature. We must also predict the inflection point.

1.3.1 Offshore oil production

The reports from the Canada–Nova Scotia Offshore Petroleum Board [Canada–Nova Scotia Offshore Petroleum Board (CNSOPB), 2010] and the Canada–Newfoundland and Labrador Offshore Petroleum Board [Canada–Newfoundland and Labrador Offshore Petroleum Board (CNLOPB), 2010] contain detailed information about the Eastern Canada offshore projects. These include the oil production by well and the production profiles. It allows us to forecast the overall production and the well count (new wells to be drilled); our results are reported in Figs. 5 and 6. We have prepared these results by splitting the total production (as estimated by our model) between the different offshore projects (that are either ongoing or announced by the industry (CNSOPB, 2010; CNLNPB, 2010)). It is important to categorize production trends by project and water-depth because the production costs are directly correlated with these factors. In Fig. 5, the total production is allocated to three different water-depth categories. The categories correspond to those used by the industry: 0–300 ft (shallow water), 300–400 ft (deep-water) and 400–1000 ft (ultra-deep water).

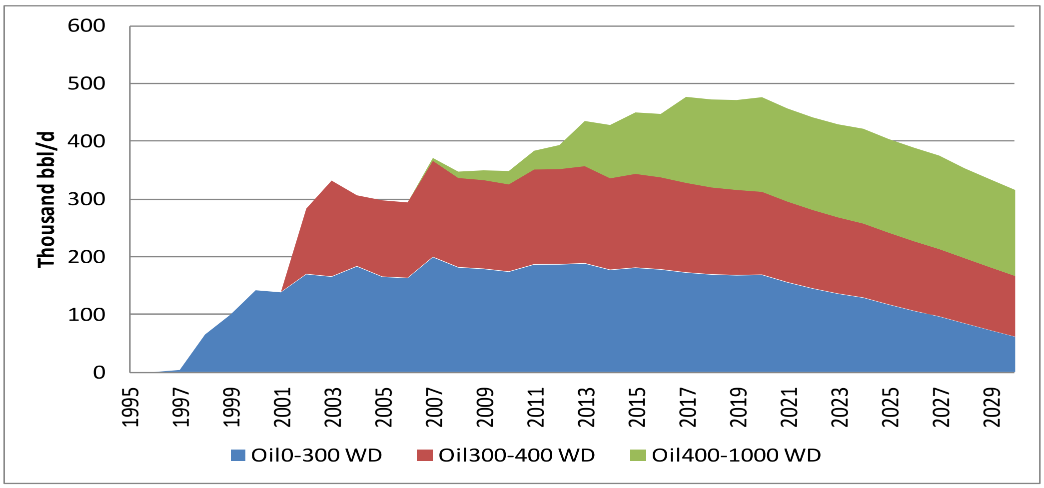

Figure 5. Forecast of the offshore oil production in Eastern Canada considering production by water depth.

Figure 6 reports the well count together with the production split between specific projects (ongoing and announced). Note that the difference between the total production forecast by our model and the total production of all the specific projects (Hibernia, White Rose, Terra Nova, Terra Nova Extension, and Hebron) is reported in the category NewOil.

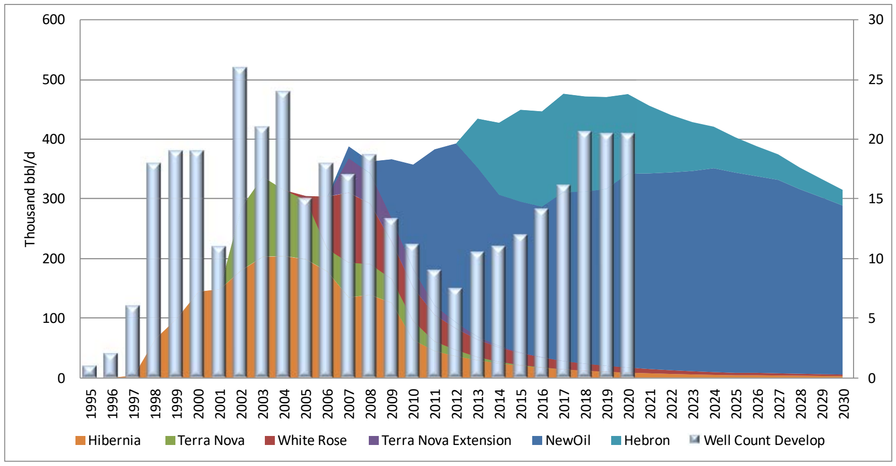

Figure 6. Offshore Eastern Canada oil production (area graph) and well count (bar chart).

Our model indicates that the oil from offshore production will continue to grow, peaking in 2020 at 476 thousand barrels per day (Mbpd). This will represent 12% of the total Canadian oil production. This value does not represent an important change (the proportion was 13% in 2008), but it is important because it will account for 53% of the total conventional oil production. The total Canadian conventional oil production in 2020 will be 900 Mbpd, according to our model. Furthermore, the production at a water depth of 400–1000 ft appears to be the most promising: the forecast for 2030 indicates a production of 315 Mbpd. As a comparison, the conventional oil production in 2008 was close to 1.4 MMbpd. The sustained growth of offshore oil production, from 350 Mbpd in 2008 to 476 Mbpd in 2020, while all other sources of light oil are decreasing, indicates the importance of Canadian offshore oil production.

The National Energy Board report indicates that in the "Reference Case" the production peaks in 2016 at 438 Mbpd, declining to 65 Mbpd by 2030 (NEB, 2007). In our forecast, the peak production occurs later, mainly because the recovery of oil prices after the 2009 economic crisis was slower than anticipated (seen by comparing the NEB expected oil prices [and the actual prices (EIA, 2011)). This slow recovery is apparent from the drop in the well count shown in Fig. 6. Another important difference is that we take into account the contribution from the Jeanne d'Arc Basin (located in Newfoundland, Canada) and 500 million barrels of reserves in other unexplored regions that could start producing in 2015. Figure 7 provides a graphical comparison of our forecast and two NEB forecasts.

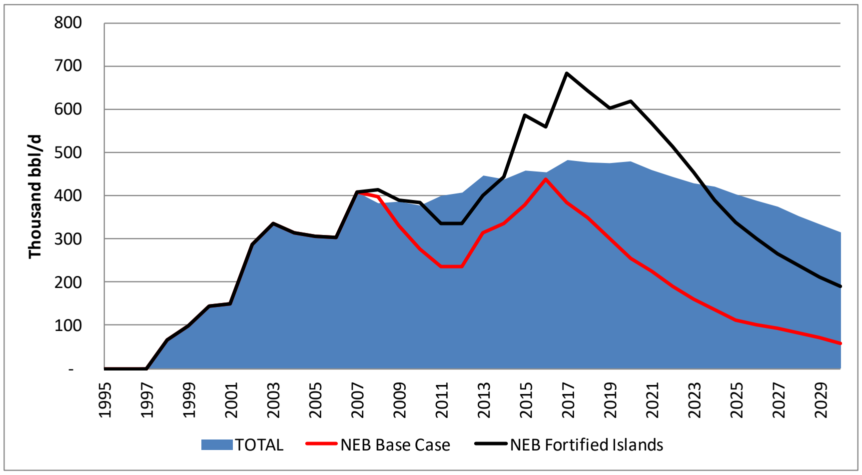

Figure 7. Comparison of our forecast and NEB's forecasts.

Figure 7 reveals that our forecast is closer to the NEB Fortified Islands scenario. In particular, the area below our curve is quite similar to that of this NEB scenario, although our production profile shows slower development after 2014 and higher development after 2024. Note that the NEB Fortified Islands scenario is characterized by a focus on security issues. Specifically, it assumes geopolitical conflicts, no international cooperation, and protectionist government policies (NEB, 2007).

1.3.2 Oil sands production

There are two types of oil sands production: mined and in-situ (upgraded and non-upgraded). In the latter category, the production is similar to that of onshore and offshore because wells are used to produce oil. In the former category, the oil production uses mining techniques rather than well construction. The National Energy Board (NEB, 2007) provides information about the different mining and in-situ projects. This allows us to forecast the oil sands production by taking into account the different projects currently under development in combination with the detailed scheduling information. However, the possibility of additional oil from new discoveries is not included, mainly because of a lack of detailed information. Because of this lack of information we must simulate the wells in order to apply our well-count approach to oil sands production. The result is then split between the different oil sand projects (mining, in-situ, and in-situ non-upgraded). An artificial well-production unit (pseudo-wells) is associated with the producing assets (trucks, mechanical shovels) of mining projects. Figure 8 displays the resulting forecast for the oil sands.

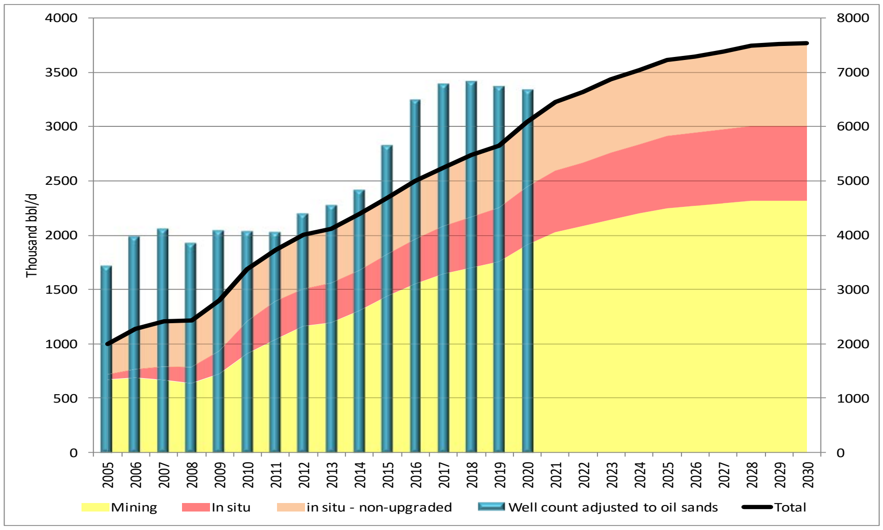

Figure 8. Forecast for oil sands production.

Comparing our results to those reported by (Söderbergh, Robelius, and Aleklett, 2005), we see that a production level of 3.5 MMbpd is achieved later (around 2025 compared to 2015). This difference reflects a slower development of the oil sands in our forecast. The slower development can be explained by the technological challenges associated with oil sands projects and other constraints such as pipeline capacity. Our forecast also reveals that peak oil levels are reached in 2030 at close to 3.8 MMbpd, distributed as follows: 761 Mbpd from the non-upgraded bitumen category and 3 MMbpd from upgraded bitumen. Figure 9 compares our results to those of (NEB, 2007), where the projection for oil sands comes from the extrapolation of their "Reference Case" trends and includes the production of the Saskatchewan oil sands, assumed to start in 2017.

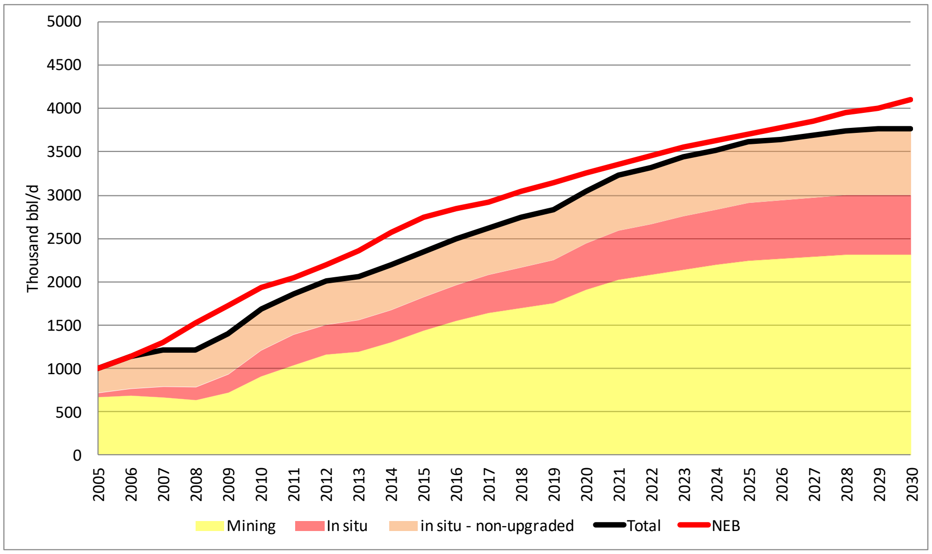

Figure 9. Comparison of our forecast and NEB's forecast.

In the NEB forecast, the oil sands production reaches 4.15 MMbpd by 2030, with 2.67 MMbpd from upgraded bitumen and 1.48 MMbpd from non-upgraded bitumen. According to our forecast, the oil sands reserves were close to 64 billion barrels in 2005. Our forecast follows rather closely that of NEB.

Combining all our forecasts for Canada, we find that peak oil happens around 2030 and the most important source is the Western oil sands, as shown in Fig. 10. Specifically, in 2029 the total Canadian oil production will be close to 4.6 MMbpd, and of this 3.8 MMbpd will come from oil sands. This represents an important change in the Canadian oil sector. First, the total oil production in 2030 will be close to double that of 2008 (slightly above 2.5 MMbpd). Second and more important, in 2030 the oil sands production will account for 81% of the total Canadian production. In 2008, only 1.2 MMbpd (47% of the total) came from oil sands. This change represents an increase of 34% in the oil sands share between 2008 and 2030. As mentioned earlier, the estimated total Canadian production from our model is comparable to the estimates of CAPP and NEB.

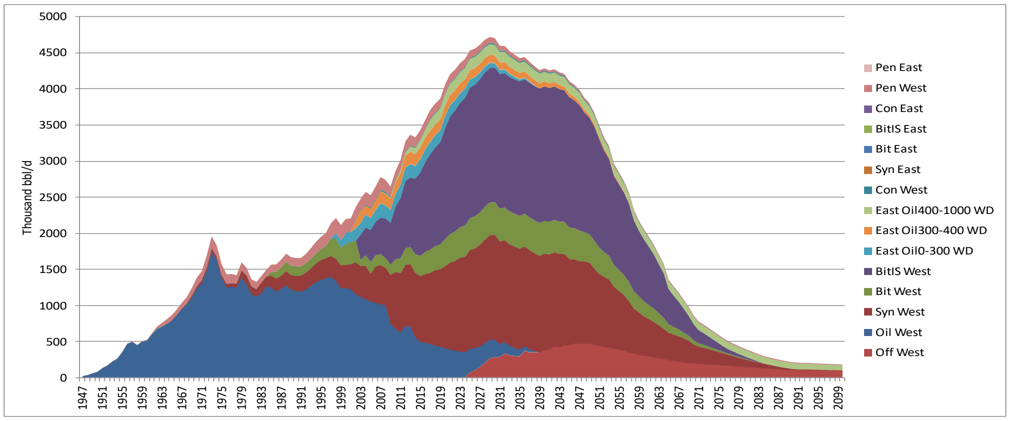

Figure 10. Total Canadian oil production for the BAU scenario.

In the next section, we use our approach to estimate the available reserves.

1.3.3 Reserves

Although our model was not originally developed to estimate the reserves, it can be used for this purpose. Assuming that we can accurately estimate the time at which the total available oil is consumed, we simply compute the area below the oil production curve (from the year under consideration to the year when the total available oil is consumed).

Our method for estimating the reserves, which is quite simple given the forecasting model we have developed, makes an important contribution by connecting the oil production, reserves, and economic variables; the literature has acknowledged this as a challenge. It is, however, important to connect reserves and prices. The economic conditions influence the feasibility of oil production projects, and this in turn affects the oil production levels. According to Jakobsson K. et al. (2009), constructing a model to explain the evolution of oil production using economic variables can be difficult. To overcome this problem, some authors use a simple extrapolation of past data (Lynch, 2002; Simon, 1996). However, this makes it impossible to grasp the dynamics involved such as the production-cost decline over time due to technological improvements and the cost increases due to peaks in demand and uncertainties about reserves. For instance, approaches that deal well with oil production forecasting do not account for the economic dimension (such as oil prices). On the other hand, models dealing with the economic dimension neglect the physical dimension (Brandt, 2010). In our model we address these issues by connecting the oil production to the well count and thus to oil prices.

To estimate the offshore reserves for 2007, we have extended the time horizon and assume that all reserves will be consumed by 2100. When computing the area below the resulting production curve, we estimate the offshore reserves to be close to 7 billion barrels. To estimate the oil sands reserves for 2005, we again assume that all reserves will be consumed by 2100, and we estimate the reserves to be close to 64 billion barrels. These volumes differ from those in the literature. For instance, NEB (2007) estimates the oil sands reserves to be 173 billion barrels. However, these reserves are not attached to a particular year, as in our case.

For 2009, we estimate the reserves to be 80 billion barrels. In 2007, BP (BP, 2007) estimated 11 billion barrels but took only active developments into account. The Oil & Gas Journal (2006) estimated around 175 billion barrels as proven reserves at the end of 2006. The NEB (2006) estimated that the Canadian oil sands contained an ultimately recoverable bitumen resource of 315 billion barrels, and from this the remaining reserves (established for 2004) were 174 billion barrels (Kjärstad and Johnsson, 2009). In 2008, BP (BP, 2008) estimated that "Canadian proved reserves include an official estimate of 21.0 billion barrels for oil sands 'under active development'" (EIA, 2009), and it recorded an additional 152.2 billion barrels of reserves, defined as "'remaining established reserves' minus the reserves 'under active development'" (EIA, 2009). Also in 2008, the Oil & Gas Journal (2008) estimated reserves of 5.392 billion barrels for conventional crude oil and condensate and 172.7 billion barrels for oil sands. Finally, in 2008 World Oil (2008) estimated 2007 reserves of 4.9 billion barrels for conventional crude and 174 billion barrels for oil sands. Note that World Oil (2008) considers these reserves not to be proven and states that their development would require at least 350 trillion cubic feet of gas and the implementation of new technologies.

These contrasting projections illustrate the difficulties of estimating the Canadian oil sands reserves.

1.4 Conclusion

We have proposed the use of a forecasting model to define oil production profiles. The novelty of our approach is that we consider both economic variables (prices) and physical variables (production and infrastructure) by establishing a link between well count, oil price, and oil production in a simple but effective way. This approach is combined with a Hubbert logistic function that takes into account the impact of the age of the producing wells. Our model can also be used to estimate the reserves, by using economic variables and trends to assess the role of those reserves and their future implications for oil production.

We have applied our model to forecast a production profile for the Canadian oil sector to 2050, distinguishing between conventional and unconventional sources. According to our model, Canadian production will reach a peak around 2030 and Western oil sands will be the most important source. We want to stress the importance of this change for the Canadian oil sector: oil sands developments have higher energy consumption, emissions, and technological costs. In addition, the poor social acceptability of oil sands may create (national and) international market barriers.

The model forecasts peak production of offshore developments in 2020, indicating that this could be another significant trend in Canadian oil production. The challenges associated with offshore production are the technological cost and the risk of ecological disasters such as the spill of 26,000 l of drilling mud into the Atlantic Ocean in March 2011 (Financial Post, 2012). However, in contrast to that of Western Canada, Eastern Canada oil production benefits from access to international markets. Moreover, the prices of Hibernia Blend usually have parity with the Brent benchmark. This is definitely an incentive for new projects, such as the new joint venture between Chevron, Statoil, and Repsol for the exploration of the Canadian offshore fields (Platts, McGraw Hill Financial, 2012).

As well as providing useful insights into the possible evolution of the Canadian oil sector, this model can be integrated into a bottom-up energy model describing the whole energy system, such as TIMES, to provide the oil supply curves that are typically exogenous to such models (Vaillancourt K. et al., 2013).

The goal of this work was to illustrate the proposed approach and it has been successfully proved. We think that this model offers a lot of potential for consulting projects and for countries with the updated oil production database, that want to represent its oil sector in a simple but effective way that will allow the integration with other bottom-up techno-economic models representing the entire energy system.

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Chapter 2
A Canadian 2050 energy outlook: Analysis with the multi-regional model TIMES-Canada

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Abstract

In terms of energy resources, Canada is an important player on the world scene. However, the energy systems of the Canadian provinces and territories are much diversified and a national energy strategy is missing in order to optimize the management of energy systems.

The objective of this paper is two-fold. First, we introduce TIMES-Canada, a new multi-regional energy model that has been developed using the most advanced TIMES optimization modeling framework, while keeping a very high level of details in the database (5,000 specific technologies; 400 commodities) compared with other Canadian energy models. Second, we define and analyze possible futures for the Canadian integrated energy system on a 2050 horizon, under five different baselines: a Reference scenario as well as four alternate scenarios corresponding to different oil prices (Low and High) and socio-economic growth trends (Slow and Fast).

In our Reference scenario, we show that the Canadian final energy consumption is expected to increase by 43% between 2007 and 2050. The Fast scenario leads to the maximum increase compared with the Reference scenario (21% in 2050). In all scenarios, oil products will continue to dominate on the long term, although in a decreasing proportion over time (from 43% in 2007 to 29% in 2050) in favour of electricity (31% of the additional demand in 2050) and biomass/biofuels. Regarding the corresponding optimal energy production paths, we illustrate two main trends: 1) a gradual replacement of onshore conventional oil & gas sources by unconventional and offshore sources (oil sands is expected to represent half of the production in 2050), and 2) a significant penetration of renewables in the electricity mix is shown after 2035 due to increases in oil import prices and decreases in renewable technology costs. The development and calibration of such a detailed technology-rich model represent an important contribution for Canada: TIMES-Canada is the only optimization model covering in details the large diversity of provincial energy systems on a long-term horizon.

Keywords: Bottom-up energy modeling, energy systems, baseline scenarios, policy analysis

2.1 Introduction

The objective of this paper is two-fold. First, we introduce the new multi-regional energy model TIMES-Canada, an application of the TIMES model generator (Loulou, R., et al., 2005), a bottom-up optimization model that represents, in details, the whole integrated energy sector from primary to useful energy. Second, we define and analyze possible futures for the Canadian integrated energy system on a 2050 horizon, under different baselines corresponding to different socio-economic growth trends. Contrary to forecast simulations and trend analysis models that focus on most likely outcomes (aiming at predicting energy futures), our optimization model aims at exploring different possible energy futures based on optimal decision (e.g., best technologies and energy forms satisfying exogenous energy demand constraints); see for instance (Bahn, O. et al., 2005). Neither predictions nor forecasts of what will happen, these outcomes correspond to consistent scenarios describing how the future for the Canadian energy sector may unfold and help decision-makers understand the key factors that influence future energy systems.

In terms of energy resources, Canada is an important player on the world scene for several reasons. First, the country is the second largest supplier of natural uranium (WNA, 2013). Second, it is an important producer of oil, gas and coal (NEB, 2011), in particular from unconventional (oil) resources such as bituminous sands. Given the global concerns about climate change, the unconventional oil industry is however facing important environmental and reputational risk challenges at the global level. Third, Canada is a crucial energy provider to the United States. At the same time, a large proportion of the energy consumed in Canada is imported, especially oil products for transportation and natural gas for industries, in Central and Eastern provinces (Statistics Canada, 2008). Consequently, energy security has become a priority on political agendas for non-producing provinces even though Canada is an important energy producer. In other words, the energy systems of the Canadian provinces and territories are diversified and lead to different future challenges depending on provinces and territories, in particular: environmental issues for fossil fuel producing provinces and energy security issues for importing and exporting provinces. In addition to this diversity of existing situations and future challenges, a national energy strategy is missing in order to optimize the management of energy systems and the conception of consistent energy policies in a way that Canadian energy systems can develop in a sustainable manner to the benefit of all provinces (Fertel, C. et al., 2012; Hofman K. and X. Li, 2009).

To study possible futures for the Canadian energy sector and support decision-makers, we propose TIMES-Canada, a new multi-regional energy model that has been developed using the most advanced TIMES optimization modeling framework, while keeping a very high level of details in the database compared with global energy models. TIMES-Canada represents the outcome of a three-year research project realized with support from the Office of Energy Research and Development (OERD) of Natural Resources Canada.

The development and calibration of such a detailed technology-rich model represent an important contribution for Canada: TIMES-Canada is the only optimization model covering in details the large diversity of provincial energy systems on a long-term horizon (up to 2100) (Connolly D., H. et al., 2010). In particular, the development of a consistent energy supply sector database represents an important contribution to energy analysis in

Canada due to the fast growing trends and data confidentiality issues. In particular, the unconventional oil & gas sectors have been evolving rapidly in recent years and significant data gathering (from governments, associations and companies) as well as modeling efforts were needed to adequately model an accurate evolution of these industries in Canada. Similarly for electricity generation capacity and annual activity, the modeling implied taking into account thousands of plant units for which techno-economic data are not publicly available. Given the significant role of Canada on the world energy scene, our results represent also an important contribution for the study of global energy trends. In addition, our work can represent a valuable contribution for global energy modelling in three ways: 1) our database can help to enhance significantly the representation of the Canadian energy sector in global TIMES model, such as TIAM-WORLD (Loulou, R. and M. Labriet, 2008; Loulou, R., 2008), 2) our detailed results can be used in global models to better calibrate their Canadian region (if existing) or their energy supply coming from international sources and 3) our model can be coupled with models presenting the US energy markets to help understand the North American energy markets.

This paper is organized as follows. Section 2.2 gives an overview of existing energy models that underlie international and Canadian official energy outlooks. Section 2.3 presents the TIMES modeling approach in general and gives the main characteristics of TIMES-Canada in particular with an overview of the database structure and content. Section 2.4 details our calibration approach. Section 2.5 provides detailed analysis of baselines, namely: final energy demand by fuel, energy supply such as oil production and electricity generation. In Section 2.6, we compare some of our results with the ones from existing outlooks before concluding in Section 2.7.

2.2 Literature review

In this section, we look at different outlooks covering Canadian trends as well as the underlying models behind these projections.

2.2.1 *International outlooks*

The two main institutions producing global energy outlooks annually are the U.S. EIA (Energy Information Administration) in Washington D.C. and the IEA (International Energy Agency) in Paris. The IEO (International Energy Outlook) of the EIA (EIA, IEO, 2011) examines 16 international energy markets, including Canada, under different socio-economic growth scenarios through 2035. Their projections are generated using the WEPS+ (World Energy Projections Plus) econometric model, a system of individual energy supply/demand modules that communicate through a central database (EIA, WEPS+, 2011). The WEO (World Energy Outlook) of the IEA (IEA, WEO, 2012) contains an assessment of future energy trends in 25 world regions, including Canada, under different policy scenarios through 2035. Their projections are produced using WEM (World Energy Model), a partial-equilibrium simulation model (IEA, WEMD, 2012). The IEA (IEA, ETP 2050, 2010; IEA, ETP 2075, 2010) provides also Energy Technology Perspectives (ETP) that corresponds to long-term assessment of optimal energy strategies under existing WEO scenarios. The primary tool for these analyses is ETP, a technology-rich model that optimizes the energy system of 15-region, including Canada, and extends the WEO scenarios to a 2075 horizon. ETP belongs to the MARKAL and TIMES family of models (see Section 2.3.1).

2.2.2 *Canadian outlooks*

At the Canadian level, three main federal entities deal with energy models for internal analysis or outlook publication. The NEB (National Energy Board), an independent federal agency, is currently the most active entity in providing energy outlooks. Their latest outlook (NEB, 2011) contains a business-as-usual scenario as well as four sensitivity scenarios projecting Canadian energy supply and demand to 2035 according to different oil prices and economic growth rates. They are developed using a two-component modeling framework: 1) Energy 2020, a North American multi-region, multi-sector model that simulates supply and demand for all fuels, and 2) TIM (The Informetrica Model), a dynamic econometric model of the Canadian economy used to generate macroeconomic projections (NEB, 2012). Both models run simultaneously and communicate in an iterative process for each year in the modeling horizon. Since 2011, the same modeling framework is used by Environment Canada, under the following name: the Energy, Emissions and Economy Model for Canada (E3MC) (Environment Canada, 2011). Their second annual report on greenhouse gas (GHG) emission projections presents a reference baseline scenario as well as alternative scenarios resulting in a range of plausible emissions growth trajectories through 2020 (Environment Canada, 2012). Finally, Natural Resources Canada has published their latest Canadian Energy Outlook (CEO) in 2006. The report (Natural Resources Canada, 2006) presented a reference scenario for Canadian energy supply, demand and emissions for 2020 using MAPLE-C (Model to Analyze Policies Linked to Energy in Canada). MAPLE-C is a modular system similar to the NEMS (National Energy Model System) model (EIA, 2013a) used for the US Annual Energy Outlook (EIA, 2013b), where each supply/demand component communicates through the integrating module and is linked to a macroeconomic module. However, the model is currently not used for providing public outlooks.

2.2.3 Canadian mitigations studies

Although policy studies are not the focus of our paper, it is worth noting that bottom-up models have also been developed within academic research centers and used to provide governmental institutions with useful insights for designing energy or climate change mitigation strategies. In particular, two Canadian models have been developed in the past for costing GHG abatement policies in the Canadian National Climate Change Implementation Process (Jaccard, M. R. et al., 2003): the CIMS (Canadian Integrated Modeling System) model developed by the Energy and Materials Research Group at Simon Fraser University and the Canadian MARKAL (MARKet ALlocation) optimization model developed by the Energy Modeling Group at GERAD (Group for Research in Decision Analysis) in Montreal. CIMS is a simulation model that includes a representation of technologies that produce goods and services throughout the economy as well as equilibrium feedbacks. More recently, the CIMS model has been calibrated to Environment Canada baselines (Environment Canada, 2011) to analyse carbon pricing policies to meet a 65% emission reduction target by 2050 (below 2006 levels) for the National Round Table on the Environment and the Economy (NRTEE, 2009; NRTEE, 2011). Note that the NRTEE has ceased operation as of March 31, 2013.As for the original

11-region Canadian MARKAL (Loulou, R. et al., 2000), it has been used for numerous studies in the past (Kanudia, A. and R. Loulou. 1998; Loulou, R. and A. Kanudia, 1998; Loulou, R. et al., 1996), but it is not being used anymore. Indeed, the modeling activities have evolved toward the construction of the next generation TIMES (The Integrated MARKAL-EFOM Systems) model generator destined to replace MARKAL (Loulou, R. et al., 2005).

2.3 Modeling approach

2.3.1 Overview of TIMES models

The TIMES model generator combines all the advanced features of the MARKAL models (Fishbone, L.G. and H. Abilock, 1981) and to a lesser extent the ones of the EFOM (Energy Flow Optimization Model) model (Van der Voort, E., 1982), as well as various new features developed over time (Loulou, R. et al., 2005). Within the Energy Technology Systems Analysis Program (ETSAP, 2013) of the International Energy Agency, MARKAL and TIMES models are currently used by more than 80 institutions in nearly 70 countries for various purposes including economic analysis of climate and energy policies.

A TIMES model represents the entire energy system of a country or region. Such a system typically includes extraction, transformation, distribution, end-uses, and trade of various energy forms and (some) materials. Each stage is described by means of specific technologies characterized by economic and technological parameters. The model also tracks GHG and criteria air contaminant (CAC) emissions from fuel combustion and processes. In baseline scenarios, end-use demands are exogenously specified in terms of socio-economic needs (e.g., transportation, expressed in vehicle-kilometres) over a future horizon.

A TIMES model is cast as a dynamic linear programming model. Under the assumption that energy markets are under perfect competition, a single optimization, which searches for the maximal net total surplus, simulates market equilibrium. Maximizing the net total surplus (i.e. the sum of producers' and consumers' surpluses) is operationally done by minimizing the net total cost of the energy system that includes investment costs, operation and maintenance costs, plus the costs of imported fuels, minus the incomes of exported fuels, minus the residual value of technologies at the end of the model horizon, plus welfare losses due to endogenous demand reductions (see below). The main model outputs are future investments and activities of technologies at each period of time. Important additional outputs of the model are the implicit (shadow) price of each energy material and emission commodity, as well as the reduced cost of each technology.

In addition, TIMES models in general acknowledge that demands are elastic to their own prices contrary to traditional bottom-up models. Although not required in our current baseline analysis, this feature makes possible the endogenous variation of demands in constrained scenarios (e.g., a nuclear phase-out policy) compared to the baseline, thus capturing the vast majority of structural changes in demands and their impacts on the energy system.

2.3.2 The TIMES-Canada model

Although an 11-region MARKAL model of the Canadian energy system has been developed at GERAD in the past, a completely new database has been built to reflect the current situation on Canadian energy markets and to fit into the new TIMES modeling paradigm. TIMES-Canada covers the energy system of the 13 Canadian provinces and territories with their own reference energy system (RES), and linked together through energy, material as well as emission permit flows. For reporting purposes, four geographical regions have been created: i) WEST: Alberta (AB), British Colombia (BC), Manitoba (MB) and Saskatchewan (SK); ii) CENT: Ontario (ON) and Quebec (QC); iii) EAST: New Brunswick (NB), Newfoundland (NL), Nova Scotia (NS) and Prince Edward Island (PE); and iv) NORTH: Northwest Territories (NT), Nunavut (NU) and Yukon (YT).

TIMES-Canada spans 44 years (2007 to 2050). Shorter time periods (1 to 2 years) are defined at the beginning of the horizon, while longer time periods (5 to 15 years) are considered afterwards, as uncertainties related to data are increasing. For each period, 12 time slices are defined uniformly across Canada, with four seasons a year (spring, summer, fall and winter) and three periods a day (day, night and peak hours). All costs are in 2007 Canadian dollars ($). The global annual discount rate has been set to 5% for this study, while future works would be relevant in order to assess the impact of higher discount rates on the future evolution of the energy system. Additional hurdle rates can be specified on a technology basis; they vary from 10% to 18% depending on the uncertainties related to their development (Loulou, R., M. Labriet and A. Kanudia, 2009).

Overall, the model database includes more than 5,000 specific technologies and 400 commodities in each province and territory, logically interrelated in a reference energy system. Fig. 11 gives a simplified representation of the reference energy system common to all provinces and territories. Each box comprises a group of technologies or more specifically representations of physical devices that transform commodities into other commodities in a particular sector or module (e.g. biomass conversion plants).

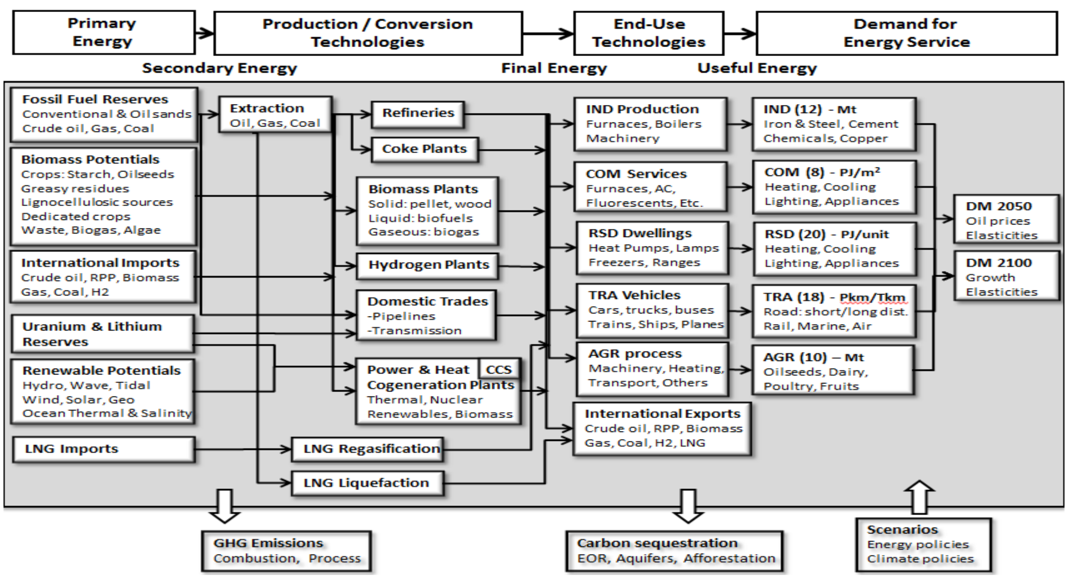


Figure 11. Simplified representation of the reference energy system of each province and territory.

All energy flows are tracked in petajoules (PJ). Besides, the model tracks carbon dioxide (CO_2), methane (CH_4) and nitrous oxide (N_2O) emissions from fuel combustion and industrial processes.

The remaining part of this section aims to illustrate the uniqueness and richness of the model database by providing some details regarding the content of each box. This description is structured according to different parts of the reference energy system: final energy (section 2.3.2.1), secondary energy (section 2.3.2.2) and primary energy (2.3.2.3). Energy trade is covered in an additional section (2.3.2.4).

2.3.2.1 Final energy consumption

The TIMES-Canada model is driven by a set of 67 end-use demands for energy services in five sectors: agriculture (AGR), commercial (COM), industrial (IND), residential (RSD) and transportation (TRA) (see Table 1).

Table 1. End-use demand segments within five consumption sectors.

Sectors	Number of segments	Units	End-use demand segments
AGR	9	Million tons	Grains and Oilseeds, Dairy, Beef, Hog, Poultry, Eggs, Fruit, Vegetables, Others
COM	8	PJ	Space heating; Water heating; Space cooling; Lighting; Street lighting; Auxiliary equipments; Auxiliary motors; Others
IND	12	Millions tons	Iron and steel; Pulp and paper (Low quality, High quality); Cement; Non-ferrous metals (Aluminum, Copper, Others); Chemicals (Ammonia, Chlorine, Others); Other manufacturing industries; Other industries
RSD	20	PJ	Space heating (Detached houses; Attached houses; Apartments; Mobile homes); Space cooling (Detached houses; Attached houses; Apartments; Mobile homes); Water heating (Detached houses; Attached houses; Apartments; Mobile homes); Lighting; Refrigeration; Freezing; Dish washing; Cloth washing; Cloth drying; Cooking; Others
TRA	18	Millions passenger-km Millions ton-km	- Road / Passenger: Small cars (Short distance, Long distance); Large cars (Short distance, Long distance); Light trucks; Urban buses; Intercity buses; School buses; Motorcycles; Off road - Road / Freight: Light trucks; Medium trucks; Heavy trucks - Rail: Freight; Passenger - Air: Freight; Passenger - Marine

In each of the five sectors, a number of existing technologies are modeled to calibrate each end-use demand for a 2007 base year (see section 4). In order to replace existing technologies at the end of their lifetime, a repository is created in each sector with a large number of new technologies that are in competition to satisfy each end-use demand after the base year. This repository includes identical or improved versions of existing technologies, as well as totally new technologies not existing in the base year. For instance, the new technology repository for residential lighting comprises standard fluorescents, fluorescents with improved efficiency and new electron stimulated luminescence (ESL) devices.

2.3.2.2 Conversion to secondary energy

This section of the reference energy system covers all energy conversion technologies such as power plants, fossil fuels transformation plants (refineries, coke plants) and biomass plants. In addition, there are separate modules for a potential future hydrogen economy and liquefied natural gas (LNG) industry (these energy forms are not consumed in the base year but available for future uses). All data sources are detailed in (Vaillancourt, K. et al., 2012).

Coke plants. The model considers the existing commercial scale plants (in Ontario) where the production of coke and coke oven gas is used by the manufacturing industries.

Refineries. The model considers the existing 19 refineries that produces a full range of petroleum products: liquefied petroleum gas (LPG), still gas, motor gasoline, kerosene, stove oil, diesel fuel oil, light fuel oil (nos. 2 and 3), heavy fuel oil (nos. 4, 5 and 6), petroleum coke, aviation gasoline, aviation turbo fuel, non-energy products.

Liquefied natural gas (LNG). In addition to the existing projects proposed on the west and east coasts for the near future, different types of generic terminals are included in the database to allow flexibility in the model for potential growth of this industry: small and large regasification terminals, as well as onshore and offshore liquefaction terminals.

Power plants. The model database depicts in much details all existing electricity, heat and cogeneration plant units in Canada, as well as units already planned for construction or refurbishment in future years. It totalizes over 3,500 existing power units including decentralized generation units (i.e. diesel generators used in remote regions). Moreover, a repository of over 150 types of new power plants has been created to analyze the replacement of existing capacity at the end of their lifetime or the addition of new capacity to meet the additional demand for electricity. The repository includes all the different types of thermal (with and without carbon capture options), nuclear and renewable power plants that can potentially be built in Canada in the near future (e.g. more efficient version of the existing plants), or that will become available on a longer time frame (e.g. fourth generation nuclear reactors, offshore wind and wave integrated system).

Biomass. Existing technologies include the 10 ethanol plants and the 7 biodiesel plants producing biofuels which meet Canadian standards at a commercial scale, as well as pellet producers in six provinces for energy and heating purposes. A new technology repository includes also more advanced options for biomass conversion, such as gasification and pyrolysis, an important module of our model. These next generation technologies can produce biofuels from a large variety of solid, liquid and gaseous feedstocks, including wood biomass, municipal and industrial wastes, biogas from manure or landfill, etc. Indeed, biomass energy represents a high potential clean alternative to fossil fuels. However, they are not yet commercially available at a large scale and cost-efficient enough to compete with the existing technologies (Srirangan K. et al., 2012), especially in baseline scenarios (without any economic or environmental incentive to promote their market penetration).

Hydrogen. This module covers the whole potential hydrogen economy, i.e. with future technologies for hydrogen production, gasification/liquefaction, distribution and sector fuel consumption. Production technologies are grouped into two main categories: large-scale production plants connected to a distribution network and decentralized small-scale units at end-use locations. They can produce hydrogen in many different ways: from fossil fuels (steam methane reforming, coal gasification, adiabatic reforming, plasma dissociation), from water electrolysis, from solar power and from biomass gasification and pyrolysis. Hydrogen can be distributed in two different forms (as a compressed gas or a cryogenic liquid) and transported via four modes (pipeline, trucks, trains, ships). Finally, hydrogen can be used mainly for electricity generation (fuel cells) and road transportation (internal combustion engine and fuel cells), but also in small-scale units in the industrial, commercial and residential sectors.

2.3.2.3 Primary energy supply

TIMES-Canada compiles all Canadian primary energy sources, such as fossil fuels reserves (oil and gas, coal), renewables potentials, uranium reserves and biomass. We detail some of them below.

Fossil fuels. Reserves are classified into three categories (located reserves, enhanced recoveries and new discoveries) which are modeled through a three-step supply curve for the cumulative amounts in the ground. Each step corresponds to a given amount of resources that can be extracted at a given cost. Primary production or extraction technologies are modeled for each type of fuel and reserves: coal, conventional oil and gas, as well as unconventional oil and gas. Afterwards, fossil fuels can be transported by pipelines and other means (trucks and trains) from primary production plants to secondary transformation plants.

Biomass. There are several types of solid, liquid and gaseous biomass that can be used to produce a large variety of energy products. They have been documented by province. In the calculation of biomass potentials, ranges were calculated using different sets of assumptions and only the most conservative ones have been retained for their implementation in the model database.

Renewable potentials. The model considers also different renewable sources for electricity generation. Technical potentials have been estimating for hydro, geothermal, tidal and wave power computing the total quantity of energy that could be produced using current technologies over the model horizon. As for solar and wind, 'accessible' potentials refer to maximum amounts of electricity that can be generated annually and have been computing considering several aspects: geographical aspects (e.g. competition for land use, population density, vegetation, and climate), technical constraints (e.g. integration to the current network, minimal wind speed) and social acceptability.

2.3.2.4 Energy trade

All primary and secondary forms of energy can be traded within and outside Canada. The domestic trade module deals with energy exchanges between the Canadian provinces and territories, where trade movements are modeled endogenously (the model computes energy prices and determines the optimal quantities up to the current infrastructure capacities). The international trade module covers all energy exchanges between Canada and other countries, including USA. Imports and exports are modeled exogenously (i.e. using fix prices and lower/upper limits on quantities) by origins and destinations as TIMES-Canada is not linked with the rest of the world. New technologies (electric interconnection, oil & gas pipelines) are available in the database to allow future increases in importing and exporting capacities between provinces and outside Canada.

2.4 Model and baseline calibration

2.4.1 Base year

TIMES-Canada has been calibrated on a 2007 base year using energy balances available at (Statistics Canada, 2007). In addition, numerous data sources were used to model energy flows in more details, including the Comprehensive Energy use Database of the Office of Energy Efficiency (OEE, 2007). As a result of our calibration process, TIMES-Canada yields for 2007 energy production and consumption consistent with official statistics for the different province and territories.

2.4.2 Projection of energy service demands

It is worth mentioning again that the aim of our paper is not to predict Canadian energy future but rather to provide consistent analyses for different scenarios of energy service demands. More precisely, our model computes optimal energy configuration (energy forms and technologies) that satisfies energy demands that have been exogenously assumed. The estimation of future demands for energy services has been done using growth rates for various socio-economic drivers applied on the base year demand, together with coefficients capturing demand sensitivity to these drivers. These drivers are related to economic (GDP) and well as demographic (number of households, population) trends.

In order to cover a large range of uncertainties related to possible future trends, we have considered five contrasted scenarios. Each scenario is based on a coherent set of assumptions about key relationships and driving forces, but we acknowledge that these scenarios ignore the possibility of major disruptions (black swan events, such as sudden economic collapses disrupting energy markets) as such events are of course inherently difficult to predict. More precisely, we have developed five different baselines using five coherent sets of growth rates (NEB, 2011): a Reference scenario, as well as four alternate scenarios characterized by different assumptions for oil prices (Low and High scenarios) or for economic growth (Slow and Fast scenarios). As (NEB, 2011) provides data until 2035 only, we have used a regressive approach to determine drivers between 2035 and 2050. Main assumptions are shown in Table 2 for 2035.

Table 2. Main assumptions in our five baseline scenarios (NEB, 2011)

Scenario	**WTI Oil Price (2010 US$/barrel)**	**GDP Growth (%)**
	2035	**2010-2035**
Low	85 $	2.3%
High	155 $	2.3%
Reference	115 $	2.3%
Slow	112 $	1.8%
Fast	121 $	3.2%

The socio-economic growth rates we use in each scenario are thus consistent with a particular oil price forecast, a major driver of energy demand. Besides, the range we consider for 2050 oil prices (from 96 to 166 US$/barrel) cover a large part of the projections available in the literature (see, for instance, (NEB, 2011; EIA, IEO, 2011; IEA, WEO, 2012; Natural Resources Canada, 2006; NEB, 2009)).

2.4.3 Existing policies

Energy and environmental policies have also a clear influence on energy supply and demand trends. Our baselines implicitly take into account the energy and environmental regulations already in place at the federal or provincial levels (but exclude non-official targets that have been proposed but not implemented yet). The most impacting regulations that have been taken into account in the baselines are (NEB, 2011; NEB, 2009): fuel efficiency standards for new vehicles; standards setting minimal renewable content in conventional fuels; and energy efficiency improvement targets.

2.5 Numerical results

2.5.1 Final energy consumption

In the Reference scenario, Canadian final energy consumption is expected to increase by 43% on the 2050 horizon. The breakdown by fuel type is given in Fig. 12.

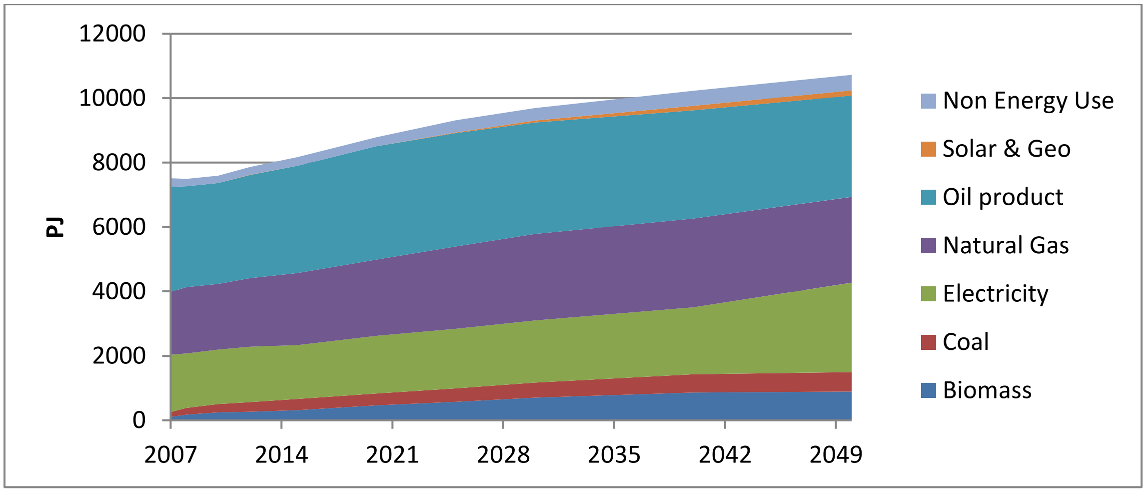


Figure 12. Final energy consumption by fuel type in the Reference scenario, 2007-2050

Figure 12 illustrates that oil products will continue to dominate on the long term due mainly to the reliance of the transportation sector on gasoline and diesel consumption, although in a decreasing proportion over time (from 43% in 2007 to 29% in 2050). Oil demand is reduced in favour of electricity & heat and biomass in particular, due to the assumed increases of oil prices on international markets on one hand, and the large variety of options available for electricity generation and biomass production (including biofuels for transportation) on the other hand. Indeed, a study specific to the transportation sector performed with TIMES-Canada shows that biofuels and electricity play a significant role for passenger transportation in baseline scenarios from 2040 (Bahn, O. et al., 2013). Finally, the largest increase is coming from electricity with 31% of the additional energy consumption up to 2050. While biomass also counts for an important part of the additional consumption (25%), its share in the total consumption remains small (8% in 2050).

Fig. 13 compares next the breakdown of final energy consumption by fuel for our five baselines in 2050.

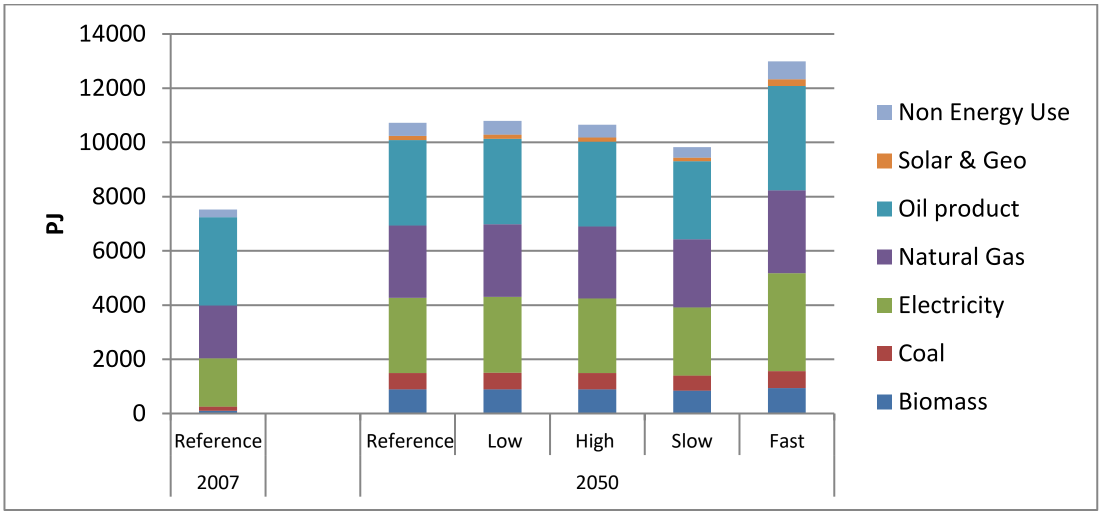


Figure 13. Final energy consumption by fuel type in our five baselines, 2007 & 2050.

The variation of results across the different baselines is consistent with our assumptions regarding the significant influence of socio-economic trends. The Fast scenario leads in particular to a 21% increase in 2050 compared to the Reference scenario, with the commercial, industrial and transportation sectors being the most sensitive sectors to economic growth assumptions. Looking at fuel type, the main impacts relate to electricity consumption that accounts for one third of the additional demand compared to the Reference scenario. Further increases are associated with natural gas (20%), biomass (15%) and oil consumption (11%). At the other end of the range, the Slow scenario leads to an 8% decline in total energy consumption by 2050.

2.5.2 Primary and secondary energy supply

This section presents optimal energy production paths required to meet final energy demand (domestic consumption) and international exports. Results are presented for three main scenarios: Reference, Fast and Slow. We choose not to report any further on the Low and High scenarios, as they are very similar to our Reference scenario.

Fig. 14 shows energy production by type in the Reference baseline.

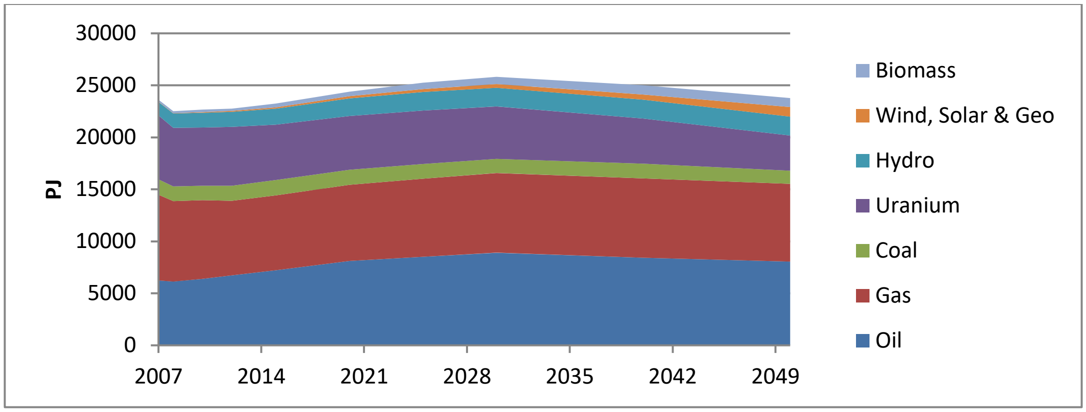


Figure 14. Energy production by type in the Reference scenario, 2007-2050

Oil production increases by 42% between 2007 and 2030 before declining by 10% between 2030 and 2050. Due to significant reserves of gas and coal, their production remains rather stable on the 2050 horizon with only a smooth decline of 9% for gas and 15% for coal. Uranium extraction follows a decreasing trend (-45% between 2007 and 2050) with the rarefaction of the reserves. On the same period, hydro follows a moderate increase (38%, mainly before 2030). Finally, although other renewable and biomass production show huge increases, with respectively 50 times and 4 times their 2007 level in 2050, their proportion of the overall production mix remains very small: 4% of total production each.

We detail next two particular sectors: oil production and electricity generation.

2.5.2.1 Oil production

The results presented in this section show the evolution of the total oil production by type through 2050 to meet both domestic demands and international exports. Since TIMES-Canada is currently not connected to global markets implicitly, assumptions have been made on future trade: oil exports from Alberta are expected to increase by 2.5 times between 2007 and 2050 in all baseline scenarios. Note that the development of the oil sector database has involved a very comprehensive and detailed documentation of all Canadian offshore (by water-depth) and oil sands (mining and in-situ) projects that are of growing importance in national oil production (Alcocer, Y. et al., 2013). The resulting production profile takes into account well counts, international oil prices and oil production.

Fig. 15 gives first the breakdown of crude oil production by type in the Reference scenario: oil production peaks at 10,760 PJ in 2030 (a 74% increase from 2007 levels) before declining to 8,160 PJ in 2050.

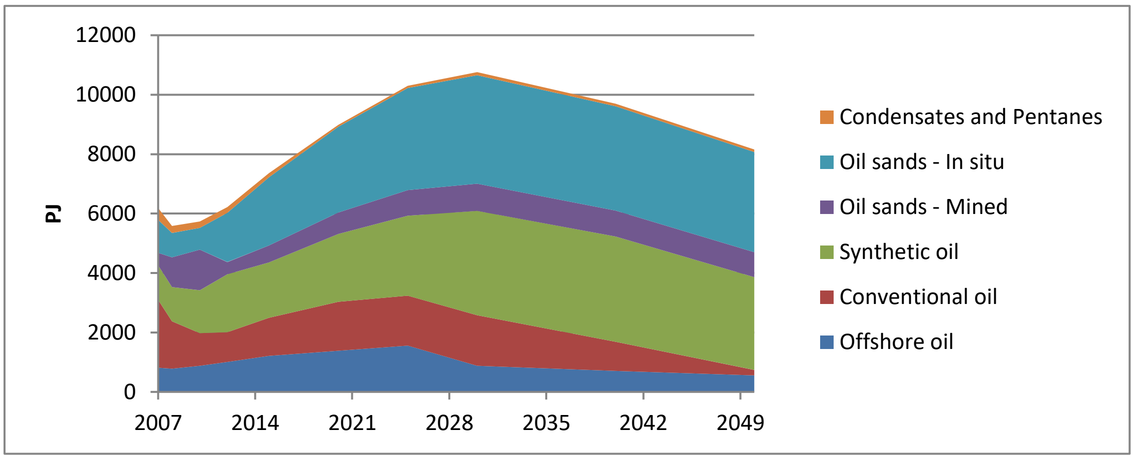


Figure 15. Oil production by type in the Reference scenario, 2007-2050

Since domestic oil demand remains quite constant over time (as illustrated in Fig. 12), most of the additional production is exported. Note that Fig. 15 reflects clearly the impact of the global economic recession between 2008 and 2010 that delayed many oil sands projects. In 2007, most of the oil production is coming from the WCSB (Western Canadian Sedimentary Basin), a mature basin where conventional oil production declines by 89% between 2030 and 2050, representing only 2% of the total oil production in 2050. The softer decrease between 2007 and 2030 is due to the availability of enhanced oil recovery options extending the life of some wells. The two sources of new project developments come from Western oil sands and Eastern offshore production. Due to the recent increase in oil prices as well as the further increasing trends predicted for the next decades (NEB, 2011), it has become profitable to exploit these new conventional and unconventional oil sources. The offshore production is expected to peak around 2020 in Eastern Canada, considering current trends and decay rate from offshore wells as well as new projects, while it is expected to start by 2025 in Western Canada. While oil sands (mined and in situ extraction) represented only a quarter of the total oil production in 2007, it is expected to represent half of the production in 2050. The proportion of oil sands extracted via in situ techniques is expected to represent 41% of the overall production in 2050, as the mined activities for oil sands extraction should remain quite constant over time. In addition, synthetic oil production from oil sands upgrading will provide another 38% of the total production in 2050.

Fig. 16 compares next the breakdown of crude oil production by type for our three main baselines in 2030 and 2050.

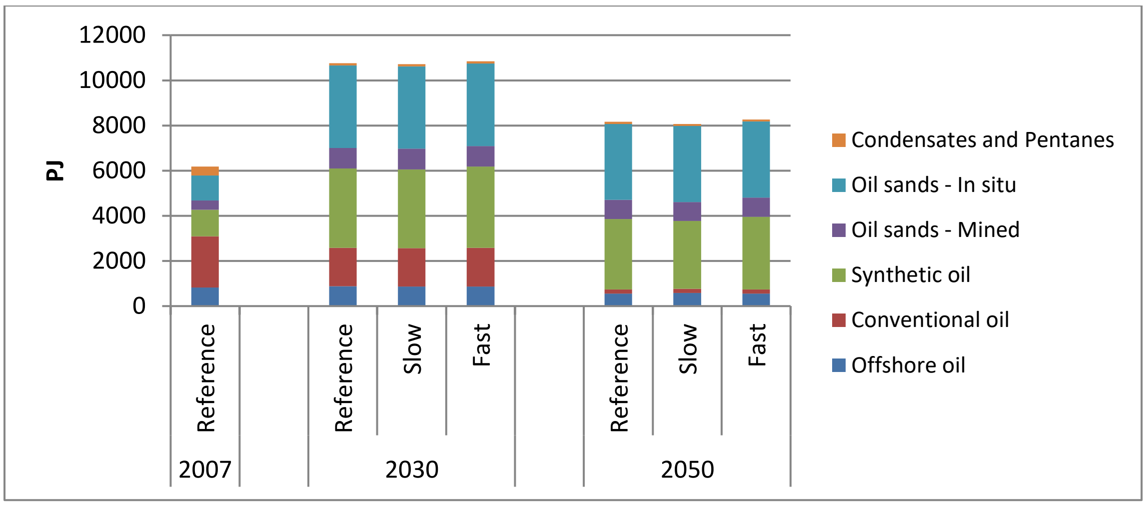


Figure 16. Crude oil production by type in our three main baselines, 2007, 2030 & 2050

In relation with the stability of the domestic demand for oil over time, it is not surprizing to see that domestic economic trends have very little impacts on oil production across the different baselines. As most of the production is exported, the international demand for Canadian crude oil and refined products is the main driver for oil production levels. However, international trade conditions remain similar in all baselines. Future works will assess the impacts of various international exports levels on the Canadian oil production. The total oil production increase by only 121 PJ in 2030 and 194 PJ in 2050 to satisfy the additional domestic demand in the fast economic growth scenario (about 1% of the production). This increases come essentially from synthetic oil.

2.5.2.2 Electricity generation

Fig. 17 reports first on the breakdown of electricity generation by type in the Reference scenario.

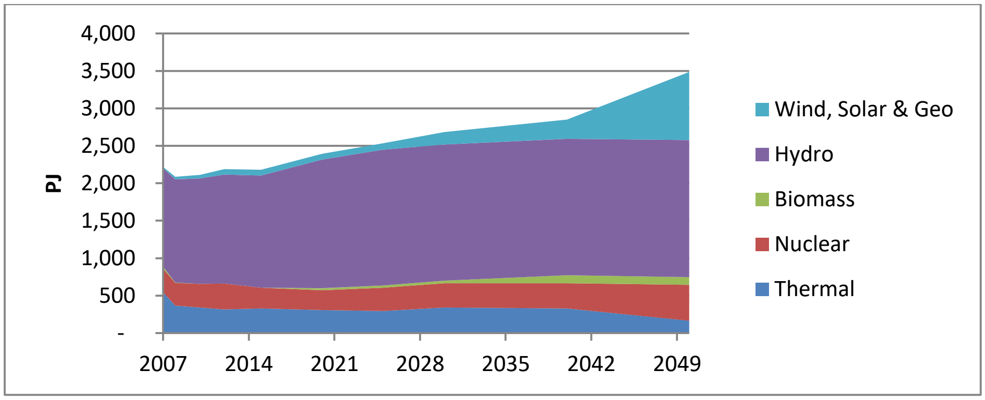


Figure 17. Electricity generation by type in the Reference baseline, 2007-2050

It is useful to recall that our baselines include ongoing projects as well as projects planned after our 2007 base year (e.g., coal phase out in Ontario, nuclear plant closure in Quebec, new hydro dams in Quebec and Newfoundland, new wind farm projects in many provinces, etc.). From 129 GW in 2007, these existing plants and scheduled projects will already bring the generation capacity to 151 GW in 2050. The model sets up new investments for an additional 66 GW of generation capacity in order to satisfy total demand in 2050. Overall, electricity generation increases thus by 57% between 2007 and 2050.

Hydro power remains the main source of electricity, although its share in the total generation slightly decreases from 59% in 2007 to 42% in 2050, due to the generation increase from other renewables. Nevertheless, a significant proportion of the additional generation is coming from hydro power in 2050 (41%), from new capacities already scheduled in British Colombia, Quebec, and Newfoundland. The largest increase comes from renewables (mainly wind) that account for 70% of the additional generation activity between 2007 and 2050. However, the share of renewable sources remains rather small in the electricity generation mix, with 25% of the total in 2050. The most significant changes relate to wind power, as important growths occur in several provinces (Quebec, Ontario, Manitoba and Alberta) that have set penetration targets. This important penetration of renewables occurs at the detriment of thermal power that decreases from 25% in 2007 to only 5% of the total generation mix in 2050. As already explained, this trend can be explained on the one hand, by the assumed increases of oil import prices on international markets and on the other hand, by a large variety of options available in Canada for renewable production. The remaining thermal power generation relies progressively more on natural gas, with the coal plant phase-out in Ontario by 2015 as well as other scheduled retirements in Western and Eastern provinces later on when plants reach the end of their useful life. Note also that oil remains the main source used for distributed electricity in isolated areas of many provinces, in the territories of the North region and on the Prince Edward Island. Nuclear power stays constant at 14% with small new capacity in Ontario, while some other nuclear plant units are refurbished. Although Canadian uranium resources are huge, the nuclear capacity is not expected to grow under our socio-economic trend assumptions. However, in relation with the development of oil sand projects in Alberta for exportations, the possibility of using nuclear power has been discussed by the oil industry.

Fig. 18 compares finally the breakdown of electricity generation by type for our three main baselines in 2050.

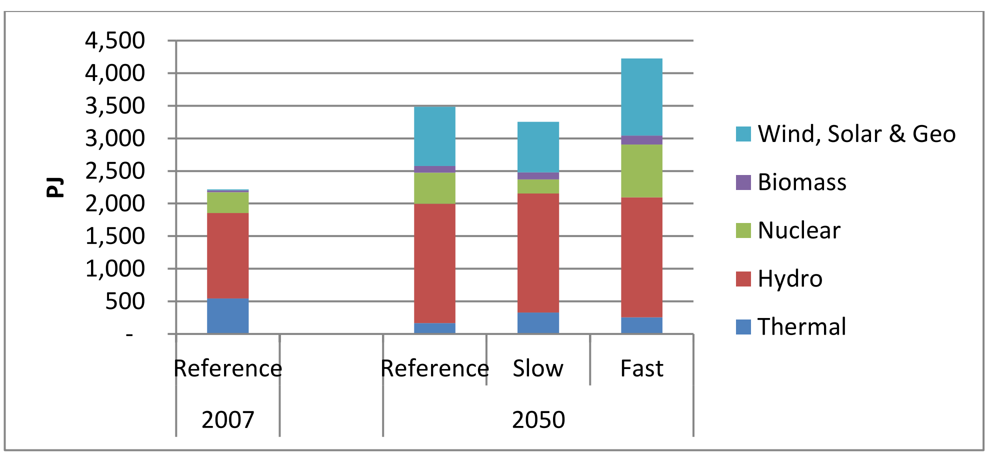


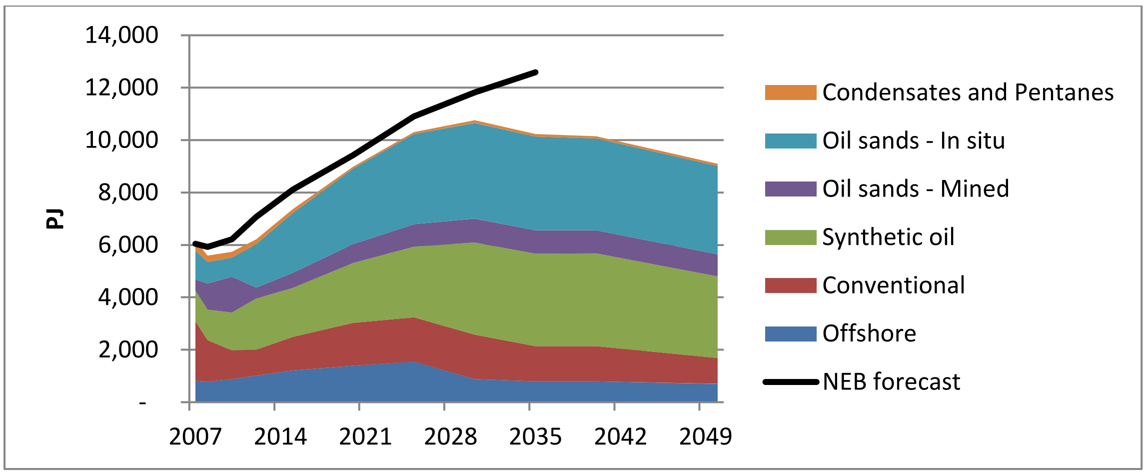
Figure 18. Electricity generation by type in our three main baselines, 2007 & 2050

In relation with the total demand for electricity in these alternate baselines, the installed capacity adjusts accordingly to reach 203 GW in the Slow scenario and 255 GW in the Fast scenario (compared with 217 GW in the Reference scenario). The Fast scenario involves a 90% increase in electricity generation between 2007 and 2050, while this rate is about 47% in the Slow scenario (compared with 57% in the Reference scenario). In absolute terms, hydro power remains similar across baselines as the techno-economic potential is already more or less exploited at the maximum. However, its share in the 2050 generation mix varies based on the total electricity generated, i.e. namely 56% in the Fast scenario and 44% in the Slow scenario. Similarly, the effects of economic growth projections on thermal power in the long term are limited due to declining reserves and rising prices; its 2050 share remains below 10% in all baselines. The main differences in the electricity generation mix refer to the trade-off between renewable power versus nuclear. As the best renewable potential opportunities are being exploited to its maximum limit in most baselines (a maximum of 25% of intermittent sources is allowed on the grid), investments in new nuclear reactors are made to cover increasing electricity demands. Biomass-fired plants are not considered a cost-effective option based on our current estimations of their techno-economic attributes, although huge potential exists for biomass of various types.

2.6 Discussion

Our current paper is based on an optimisation model that defines optimal configuration of the Canadian energy sector in order to satisfy projected demands for energy services. Some outlook publications are using alternative approaches (such as simulation models, econometric models, partial equilibrium models) to provide energy outlook for Canada specifically (NEB, 2011) or for the entire world with Canada as a separate region (EIA, IEO, 2011; IEA, WEO, 2012). Other publications are using similar optimization approaches (IEA, ETP 2050, 2010; IEA, ETP 2075, 2010) at the global level and covering Canada, but in a much less detail manner. It is difficult to directly compare results with the ones we obtain due to the numerous differences between the various outlooks: approaches and models, geographical coverage, time frame, definition of the energy system, end-use sectors and fuel categories, level of details, underlying assumptions, and so on. In particular, it is not possible to compare final energy demand directly, as its definition is not the same across sources. In particular, energy demands in TIMES-Canada are specified in physical units, while they are specified in energy units in other Canadian models. Besides, different outlooks do not necessarily report on the same section of the Canadian energy balance.

However, some comparisons in the supply sectors are possible with some outlooks. Regarding oil production, the only comparable source is the (NEB, 2011) and their estimates show comparable trends until about 2025 (see Fig. 19).



* The NEB (2011) data is converted to PJ using an average coefficient that equal their 2007 estimates with the number provided by Statistics Canada (2007) for oil production.

Figure 19. Comparison of the oil production in the Reference scenario, 2007-2050

Afterwards, more significant differences occur, due to different assumptions regarding the evolution of the oil industry. Indeed, (NEB, 2011) uses more optimistic assumptions related to increase in the application of multi-stage hydraulic fracturing in tight oil, prospects for enhanced oil recovery by carbon capture and sequestration in wells, and assume that all energy production will find markets and that all necessary infrastructure will be built.

Finally, the comparison of installed capacity for electricity generation with the (NEB, 2011) and the IEO (EIA, IEO, 2011) in Fig. 20 is relevant to illustrate robust (but slow) trends toward the development of a large variety of renewable projects.

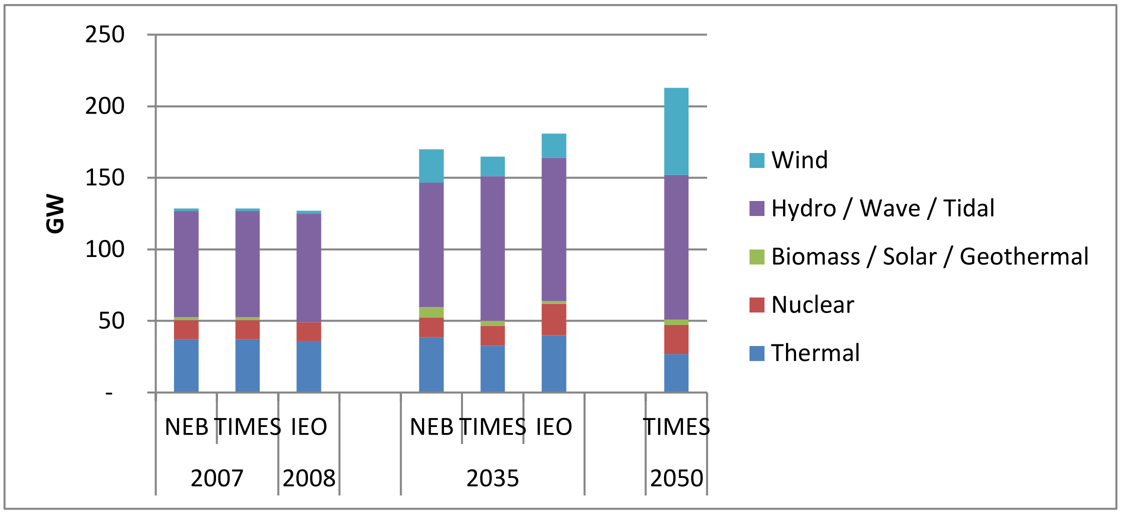


Figure 20. Comparison of the electricity capacity in the reference baseline, 2008, 2035 & 2050

The share of hydro, biomass and other renewables power reaches 66% (EIA, IEO, 2011), 69% (NEB, 2011) and 72% (TIMES-Canada) respectively in 2035. Our assumptions lead to the most optimistic estimation regarding the development of renewables at the detriment of thermal power. The main assumption being the availability of a significant portion of the potential not yet exploited as of today, as well as the documentation of a large variety of new options available in the model database to develop the remaining potential in a cost-effective manner on the long term. Official projections relies rather on past and current trends ignoring the potential contribution of promising technologies that are still not wide spread or still under development, such as onshore and offshore wind as well as tide and wave power, high potential renewable resources in many countries (Esteban M. and D. Leary, 2013), including Canada. The result of our model is an important contribution in this sense and even more by looking at the extended trends toward 2050 showing an increasing role for renewables.

2.7 Conclusion

In this paper, we use the newly developed TIMES-Canada model to define and analyze possible futures for the Canadian integrated energy system on the 2050 horizon, under different baselines corresponding to different oil prices and socio-economic growth trends.

We have shown that the total Canadian final energy consumption is expected to increase by 43% on the 2050 horizon in the Reference scenario. The fast economic growth baseline (Fast scenario) leads to a 21% increase in total final energy demand for 2050 compared to the Reference scenario, while the slow economic growth baseline (Slow scenario) leads to an 8% decline in the total energy demand for 2050. The effects on the fuel mix are derived from the different factors affecting the different end-use sectors and their different reactions to a change in the demographic and economic growth rates. In all scenarios, oil products will continue to dominate the markets on the long term due mainly to the reliance of the transportation sector on gasoline and diesel consumption, although in a decreasing proportion over time in favour of electricity which accounts for 31% of the additional energy demand up to 2050.

Regarding the optimal energy production path required to meet final energy demand for the Reference scenario, it shows: 1) a gradual replacement of onshore conventional oil & gas sources by unconventional and offshore sources through 2050; and 2) significant penetration of renewables in the electricity mix, namely after 2035 due to increases in oil import prices and decreases in renewable technology costs. Although similar trends are observed in other outlooks (NEB, 2011; EIA, IEO, 2011), our assumptions lead to more optimistic estimation regarding the development of renewables for electricity generation at the detriment of thermal power. This is due to the large number of new options available in the model database to develop the remaining potential in a cost-effective manner on the long term.

These results illustrate the relevance of using such a technology-rich optimization model for technology assessment from different baselines. For this purpose, a very detailed database has been built to reflect the current situation on Canadian energy markets and to fit into the TIMES modeling paradigm. In addition, the objective was to integrate emerging technologies that are particularly relevant in the Canadian context in order to provide the model with more flexibility regarding the technology selection and the fuel mix required to satisfy the projected demand through 2050. Special attention has been dedicated to the construction of an accurate technology database in fast-evolving sector such as oil sands extraction and liquefied natural gas imports, but also next generation biomass conversion plants, next generation of nuclear reactors, clean coal technologies, carbon capture and sequestration (CCS) options, hydrogen, electrification of transportation, new power plants with CCS options, etc.

The development of such a comprehensive database and the calibration process behind the final results represent significant contributions to the energy modeling capacity for Canada, especially because of the particularities inherent to the Canadian energy system, its recent evolution and data confidentiality issues. The resulting model, TIMES-Canada, is the only optimization model covering the large diversity of provincial energy systems in Canada on a long-term horizon (2050) in such details. Future works will benefit from this powerful tool through sensitivity analyses on techno-economic attributes to assess the potential of emerging technologies in Canadian and provincial energy and climate policies. In particular, we will be working together with our initial supporting organization, Natural Resources Canada, as well as other federal and provincial entities, to set up a series of interesting matters such as: creating the appropriate infrastructure for electricity trade into an integrated electricity market, testing different hypothesis for market potential of renewable energy technologies, exporting versus using unconventional oil & gas sources, fulfilling renewable and specifically climate change mitigation targets.

Finally, further refinements will be brought to the model in parallel, namely with the calibration of the energy demand and production towards the 2100 horizon as well as the review of the techno-economic attributes of technologies and the addition of new technologies as the information becomes available from other research.

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Chapter 3
An analysis of the impacts of new oil pipeline projects on the Canadian energy sector with a TIMES model for Canada

Kathleen Vaillancourt, Yuri Alcocer and Olivier Bahn

Abstract

The oil industry currently plays a major role in the Canadian economy. In the future, further developments of the oil sector will be affected by the ability to transport crude oil (mainly from Western Canada) to consuming regions in Canada and abroad. This paper analyzes different crude oil exportation scenarios based on existing pipeline expansions and the development of new pipelines. We use for this a multi-regional TIMES energy model for Canada. Our results indicate that: i) the exporting capacity will be an important driver for oil production levels in Canada, and ii) impacts on the other Canadian energy sectors are rather limited.

3.1 Introduction

It is an understatement to allege that the oil industry plays a major role in Canada's economy and development. Considering crude oil alone, with over $69 billion of private investment in 2013, it represents nearly a fifth of Toronto's Stock Exchange value and pays over $18 billion to the provincial and federal governments in taxes and revenues each year (CAPP, 2014a). Providing over 550,000 direct and indirect jobs in the country, the oil industry is the backbone of Canada's actual economy and financial stability.

In 2013, Canada's crude oil production reached an approximate total of 3.5 million barrel/day (bbl/d), of which 1.9 were produced from oil sands. It is expected that by 2030, Canada will produce a total of 6.4 million bbl/d, with crude oil from bitumen representing over 90% of this augmentation (CAPP, 2014b). Even if new techniques and technologies improve the actual life expectancy of conventional oil reserves, oil sands, with a fast expending capital investment and the recent confirmation of new reserves, is where the growth is expected. Of the 339 billion barrels of crude oil that represent Canada's estimated resources by the end of 2012, oil sands bitumen and conventional crude are in a respective proportion of 90% and 10% (NEB, 2013). All of Canada's bitumen resources can be found in Alberta and Saskatchewan. Canada owns the third-largest reserves of oil in the world, just after Saudi Arabia and Venezuela.

However, every actor in the industry agrees that in order to achieve such a progression in production, Western Canada's oil must find a demand for its offer. As Alberta and Saskatchewan are inland provinces, without access to tidewater ports, they are in need to develop their capacity to export this expected production. It is now becoming a political, economic and national security matter that this oil finds access to tidewater and export opportunities (McKenna, 2013). As for their actual markets, maintenance on existing pipelines and the necessity of upgrading refineries receiving the crude oil form Western Canada, create bottleneck in the distribution system that furthermore puts pressure on expected growth. Already, the impact of this surplus in crude, and the inability to reach external markets, produces negative effects for the industry. Furthermost, is the price discount that Canadian oil producers must pay for their inability to reach markets, putting negative pressure on their profits. From 2011 and 2012, the Western Canadian Select (WCS), the price reference for Canadian heavy crude, traded up to US$19/bbl below West Texas Intermediate (WTI). This price reflects also the difference in quality of the two products (CAPP, 2014b).

Seeing how, in the short term, production is straining pipeline capacity and will soon exceed transportation capacity, implementing only long-term solutions may jeopardize this intended growth. On the order hand, short-term solutions may prove useful in the interim, as such, the transport by rail cars may prove an interesting temporary solution. Rail cars shipping is expected to increase in Canada from about 200,000 bbl/d in late 2013 to 700,000 bbl/d by the end of 2016 (CAPP, 2014c), about the transport capacity of a major pipeline. Even with this rapid development, Western Canada must increase dramatically its capacity to export.

The objective of this paper is to analyze different crude oil exportation scenarios based on existing capacity expansion and new pipeline projects taking off from the Western Canadian Sedimentary Basin (WCSB) to reach North American, Asian or domestic markets. For the maximum levels of oil exports corresponding to the available pipeline capacity in each scenario, we compare both the impacts on the final energy demand and on the crude oil production profiles.

This paper is organized as follows. Section 3.2 gives an overview of the different markets opportunities for supplying Canadian oil while Section 3.3 presents the database structure for the oil sector. Section 3.4 details our scenario definition. Section 3.5 provides contains the analysis of all scenarios, namely the impacts on the Canadian oil sector in particular and on the energy system in general. In Section 3.6, we compare some of our results with results from existing outlooks before concluding in Section 3.7.

3.2 Canadian oil exportation options

It falls to the industry and governments to find and open new markets in order to achieve a significant increase in oil production. Three markets are therefore considered: 1) Central and South USA markets, 2) Canadian and USA West coasts and Asia, and finally 3) East Canada and Eastern USA.

3.2.1 Central and South USA markets

The Midwest or PADD II district (Petroleum Administration for Defense District), is currently the largest market for Canada's oil, for an approximate amount of 1.7 million bbl/d. These markets are connected to Canada by two major pipelines, Enbridge Mainline and TransCanada Keystone. Both of these networks are suffering from overload capacity and are in need of major improvements. Secondly, PADD II's refineries are already receiving most of their foreign oil (98% in Eastern district) from Canada, allowing less space for new market shares. Finally, recent years have seen an increase in tight and crude oil, as well as in natural gas in the USA. This new production is mainly directed in this district, competing directly with Canada's oil (EIA, 2014). With these constraints, demand is anticipated to reach only 2.2 million bbl/d in 2020.

The main hope for future exportation resides in PADD III, Gulf district. It is home to half the refining capacity of the USA, with over 9.4 million bbl/d (EIA, 2014). From this amount, 3.7 million bbl/d of crude were imported, mainly from Saudi Arabia, Mexico and Venezuela. But this share is diminishing rapidly with the surge in local oil, 17% in 2012 alone. Mexico is producing slightly less each year and Venezuela is constantly threatening to diminish its offer to USA markets as a political lever. These trends, and the fact that the refineries in the Gulf are the most sophisticated in North America, already able to receive and transform Canada heavy crude, makes it an excellent option for exportation. Since this is a remote region from Western Canada, to reach this market, the authorities have been pushing its project of TransCanada Keystone XL for over 5 years now. If completed, it would provide an additional 830,000 bbl/d of capacity.

3.2.2 Canadian and USA West coasts and Asia

By improving the pipeline network of Kinder Morgan Trans-Mountain (+590,000 bbl/d) and by developing the Enbridge Northern Gateway (525,000 bbl/d) between Edmonton and Kitimat, Western producers wish to accede to tidewater and therefore to Asian and Western USA markets. However, most of the extra capacity of the Kinder Morgan Trans-Mountain is already locked by firm 15-20 years' contract to Washington's refineries. It is primarily the Northern Gateway project, with its tidewater port at Kitimat, that could open the new and avid markets of India and China for Canada's crude oil. Singapore and Japan could also become interesting markets for light crude since they already have an extended refining industry for this product. Furthermore, the cost of transportation by tankers is also on par with the pipeline tariffs to USA refining markets (Wood-Mackenzie, 2011). A tidewater access could also mean reaching PADD III and its attractive refining industry.

3.2.3 Eastern Canada and Eastern USA

Moreover, Western producers are also considering new markets on the other side of the country. Refineries in Québec and Atlantic Provinces import more than 80% of their crude oil (642,000 bbl/d) from international markets, which makes them perfect targets for the expanding production. It is an argument in favor of the country's energy security. These regions' four refineries can handle heavier crude without much modification to their installation and their products could therefore be exported to Eastern USA. There is also the advantage of an existing, but incomplete network of pipelines that could be used to transport large amount of crude to these regions. In Ontario, in 2013, the refineries processed 380,300 bbl/d of crude oil from Canadian producers (94% of capacity) with the first phase of the re-reversal of Enbridge line 9 of the same facilitating transportation. PADD I district is also a potential market that, if reached, may want to change its international imports to a more local and secure supply. Two pipeline projects are key to open these new markets, the re-reversal of Enbridge line 9 A and B, and the TransCanada Energy East Pipeline. If they were to be accepted in their actual form, they would add respectively 300,000 bbl/d and 1 million bbl/d to Québec's and Atlantic refineries.

3.3 Modeling the Canadian oil sector

The multi-regional energy model used for this study is an application of the TIMES model generator (Loulou et al., 2005) supported by the Energy Technology Systems Analysis Program (ETSAP, 2014) of the International Energy Agency. More precisely, this TIMES model for Canada is part of a larger modeling framework: The North American TIMES energy model (ESMIA, 2014).

The model covers the energy system of the 13 Canadian provinces and territories. The model spans 90 years (2011 to 2100) and this study will cover 2011-2050 through nine time periods and 16 annual time slices: four seasons (spring, summer, fall and winter) and four intraday periods (day, night, morning peak, evening peak). All costs are in 2011 Canadian dollars (CAD$). The global annual discount rate has been set to 5% for this study. The model is driven by a set of 70 end-use demands for energy services and the database includes more than 4,500 technologies and 800 commodities in each jurisdiction, logically interrelated in a reference energy system. As a result of our calibration process, this TIMES model for Canada yields for 2011 energy balances and greenhouse (GHG) emissions consistent with official statistics (Statistics Canada 2011, 2012; OEE 2011; NEB 2013; Environment Canada 2013) for the different province and territories.

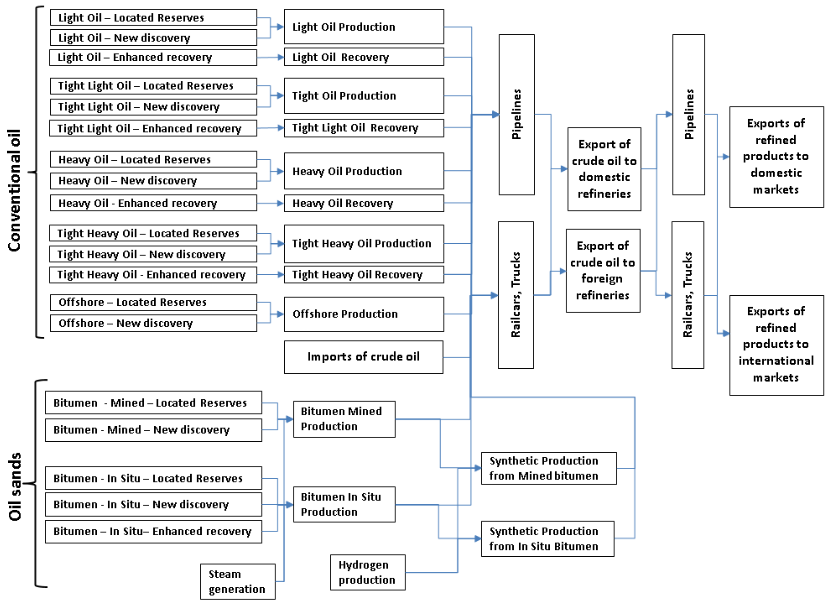

Figure 21. Simplified representation of the oil supply sector

In particular, Fig. 21 gives a simplified representation of the oil sector in the model. Supply curves have been built from the latest data available from NEB (2013) and CAPP (2013) for the different types of oil (conventional and non-conventional), reserves (located reserves, enhanced recoveries and new discoveries) and extraction techniques (mined and in situ). Most of the Canadian oil reserves (93%) are located in the WCSB spread in four main provinces (Alberta, Saskatchewan, British Columbia, Manitoba). Extraction technologies are modeled for each type of oil and reserves, including several new methods for in situ extraction. Most of the mined bitumen (95%) is currently upgraded into synthetic oil, while the in situ bitumen is mixed with condensates to produce a diluted bitumen appropriate for transport by pipeline.

Downstream activities includes six upgraders with a total capacity of 1.2 million barrels per day and 19 refineries with a total capacity of 2.06 million barrels per day and producing a full range of refined products (CAPP, 2014b). Only a small number of refineries in Ontario and Alberta are currently configured to upgrade bitumen directly. All technologies are characterized by different costs and energy requirements. An important quantity of natural gas is use for steam generation (bitumen recovery) and hydrogen production (bitumen upgrading). Corresponding GHG emissions from fuel combustion and fugitive emissions are accounted at each step of the supply chain as well as flaring and venting emissions.

Table 3. Existing and proposed pipelines for international exports

Pipeline	Target In-Service	Capacity (k bbl/day)	Capacity (PJ)
Enbridge Mainline	1950	2500	5,651
Kinder Morgan Trans Mountain	1953	300	678
Spectra Express	1997	280	633
TransCanada Keystone	2010	591	1,336
Total Existing Capacity		**3,671**	**8,298**
Enbridge Alberta Clipper Expansion	2014	120	271
Enbridge Alberta Clipper Expansion	2016	230	520
TransCanada Keystone XL	2020	830	1,876
Trans Mountain Expansion	2017	590	1,334
Enbridge Northern Gateway	2017	525	1,187
Total Proposed Capacity		**2,295**	**5,188**
Total Capacity		**5,966**	**13,486**

The model database includes the current existing transportation capacity as well as already planned projects for existing capacity expansion or new infrastructure. Due to the location of the main production centers in the WCSB and of the major markets in the USA Midwest and Gulf Coast regions, the pipeline network in North America has a strong North-South linkage. There are actually four main pipelines exiting the WCSB with a total capacity of 3.67 million barrels per day. The existing pipelines as well as planned projects are listed in Table 3 for exports from the WCSB to international destinations; they can all be visualized on maps in CAPP (2014b). In addition, rail transportation capacity has evolved quickly from 46 thousand barrels per day in 2012 to 300 thousand barrels per day in 2014 (CAPP, 2014b). The growth in available rail capacity is expected to slow down and reach a maximum of 945 thousand barrels per day in 2050.

As for domestic trade, two major new projects are proposed and they are considered as future investment options in the model (Table 4) (CAPP, 2014b). These projects would allow synthetic oil from the WCSB to be exported to Eastern refineries (not equipped to process bitumen) and consequently for Quebec and New Brunswick to reduce their imports from foreign countries.

Table 4. New pipelines for domestic exports

Pipeline	Target In-Service	Capacity (k bbl/day)	Capacity (PJ)
Enbridge Line 9 reverse	2015	300	678
TransCanada Energy East	2018	850	1,921
Total Proposed Capacity		**1,150**	**2,599**

The model captures six types of oil commodities that can be transported by pipelines and/or other means (trucks, trains and tankers) from primary production wells to different types of destinations: domestic refineries, USA refineries and export terminals (e.g. Kitimat in BC) reaching two aggregated international regions (Rest of the World – East and Rest of the World – West). While international trade movements are modeled using fix prices and limits on quantities by origins and destinations, domestic trade movements within Canada are determined endogenously.

3.4 Description of scenarios

For this study, end-use demand have been projected using a coherent sets of socio-economic drivers (NEB, 2013), together with coefficients capturing demand sensitivity to these drivers. This approach builds on Vaillancourt et al. (2014) where five different baselines were developed and characterized by different assumptions on oil prices or economic growth covering a large range of uncertainties related to possible future trends. We have used here the central baseline scenario consistent with an oil price reaching 123 US$/barrel in 2050.

3.4.1 Pipeline capacities in the baseline scenario

Baseline (BAU): This scenario illustrates the situation where all new projects would take place. The following assumptions are used to define the real availability of pipelines for exportation from the WCSB (CAPP, 2014b):

- Enbridge Mainline: The pipeline is used at 70% of its existing capacity for international exports (USA) and at 5% for domestic exports (Ontario), while the remaining portion (25%) is not available due to the competition with the oil entering the pipeline on the other side of the USA border.

- Enbridge Alberta Clipper Expansion: About 90% of the total capacity will be used for international exports and 10% for domestic exports (Ontario).

- Kinder Morgan Trans Mountain and Expansion: Most of the capacity is currently used to export oil to the USA (70%), and to the rest of the world through terminals in British Columbia (26%). A small portion (4%) is already used for carrying oil to domestic refineries in British Columbia.

- Spectra Express and TransCanada Keystone: These pipelines are available at 100% to export oil to USA.

- TransCanada Keystone XL: This pipeline would be available at 100% to export oil to USA.

- Enbridge Northern Gateway: This pipeline would be available at 100% to export oil to ROW.

- Enbridge Line 9 reverse & TransCanada Energy East: These pipelines would be available at 100% to export oil to Central and Eastern Canada.

Given these assumptions, the remaining available capacity is 4,858 PJ and is expected to be doubled by 2020 with an additional 4,986 PJ of capacity (Table 3).

A breakdown by type of destinations gives a better illustration of the saturation levels and potential for increases. Most of the existing capacity is used to export oil to Southern markets (capacity used at 97%), while only a marginal portion is sent to Western markets (used only at 15%). The addition of new capacity will allow increasing current exportation levels to the Southern markets by 1.79 times and to the Western markets by 65 times.

Table 5. Available pipeline capacity for oil exports by destination

	Existing capacity	New capacity	Total capacity	Exports in 2011	% of capacity in 2011
	PJ	**PJ**	**PJ**	**PJ**	**%**
Southern markets	4,679	3,448	8,127	4,546	97%
Western markets	179	1,538	1,717	27	15%
Total international	**4,858**	**4,987**	**9,844**	**4,573**	**90%**
Eastern: up to Quebec		678	678		
Eastern: up to New Brunswick		1,921	1,921		
Total domestic		**2,600**	**2,600**		

3.4.2 Pipeline capacities in three alternate scenarios

We have defined three alternate scenarios which differ in terms of the pipeline capacity available to supply the WCSB oil on various markets.

- Southern markets (No South): This scenario represents a situation where there would be less additional options for WCSB oil to reach South and Central USA markets. The following project would never occur: TransCanada Keystone XL (1,876 PJ of additional capacity for international trade).

- Western markets (No West): This scenario builds on the previous one and represents a situation where there would be also less additional options for WCSB oil to reach Canadian and USA West Coast and consequently Asian markets. The following projects would never occur: TransCanada Keystone XL (1,876 PJ of additional capacity for international trade) as well as the Enbridge Northern Gateway (1,187 PJ of additional capacity for international trade).

- Eastern markets (No East): This scenario represents a situation where there would be no additional options allowing WCSB oil to reach refineries in Central and Eastern Canada (more precisely Quebec and New Brunswick). The following projects would never occur: Enbridge Line 9 reverse and TransCanada Energy East (2,600 PJ of additional capacity for domestic trade).

3.5 Analysis of scenarios

In this section, we present the impacts on the Canadian oil production levels and trade movements both within and outside Canada in all four scenarios: on the oil sector specifically (Section 3.5.1) and on the overall energy system in general (Section 3.5.2).

3.5.1 Impacts on the Canadian oil sector

These results show the evolution of the total oil production to 2050 to meet both the domestic demands and international exports. Fig. 22 illustrates the breakdown of crude oil production by type in all scenarios. In the BAU scenario, oil production increases by 1.72 times between 2011 and 2030 level and peaks at 12,045 PJ in 2030 before starting its decline to reach 10,492 PJ in 2050. The highest growth occurs between 2020 and 2030 after all pipeline projects have been built and the available capacity for exports has reached its maximum. The stability in the share of conventional oil between 2011 and 2030 is due to the availability of enhanced oil recovery options extending the life of some wells and the extraction of tight oil. However, conventional and tight oil production declines by significant faster rates between 2030 and 2050, representing only 10% of the total oil production in 2050. While oil sands represented already half of the total oil production in 2011, it is expected to represent 88% of the production in 2050. The proportion of oil sands extracted via in situ techniques alone is expected to represent 67% of the overall production in 2050. A significant portion of this oil sands production via mined or in situ techniques is converted to synthetic oil.

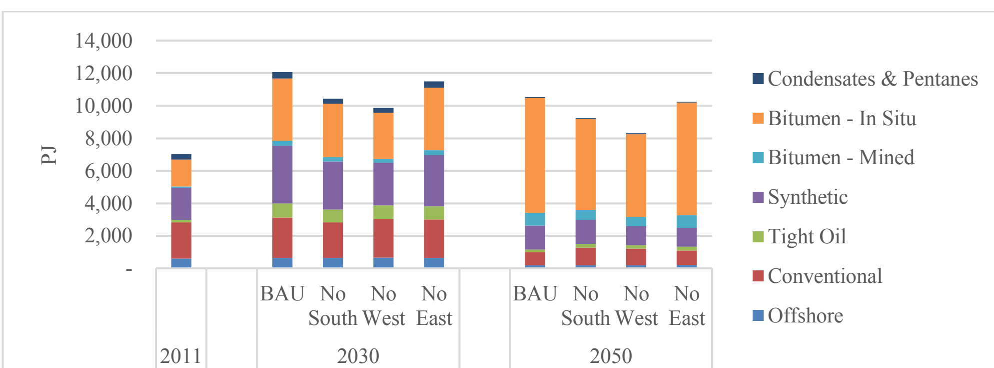

Figure 22. Oil production by type in all scenarios

Oil production levels in the three alternate scenarios show the significant impacts of available pipeline capacity for international exports: total oil production is 18% lower in the No West scenario than in the BAU scenario in 2030 and 21% lower in 2050. Conversely, the impacts of available pipeline capacity for domestic exports are non-significant, with only a 2% decrease in 2050. As most of the production is exported, the international demand for Canadian crude is the main driver of oil production levels. A very large proportion of all the oil produced in the WCSB is exported to international destinations: 64% in 2011 to 82% in 2050 (Fig. 23). Consequently, the availability of the pipeline capacity for international exports has direct impacts on oil production levels while the effect of domestic exports is minor. In terms of international destinations, oil exports are almost exclusively oriented to USA markets by pipeline in 2011 but diversify on the long-term both in terms of transportation means and other destinations due to (the assumed) higher oil prices.

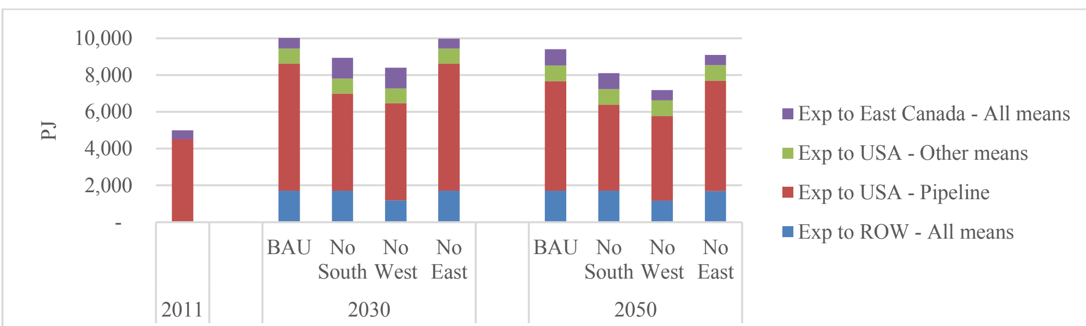

Figure 23. Oil exports by destination in all scenarios

3.5.2 Impacts on the Canadian energy system

The availability of pipeline capacities do not significantly affect final energy consumption in Canada, even if fossil fuels continue to represent a large part of the fuel mix in the long term. Looking at the primary energy consumption (Fig. 24), energy uses in the supply sector is reduced along with the decline in oil production and exports: energy uses in the supply sector reach 2,729 PJ in the BAU scenario, but only 2,302 PJ in the No West scenario. However, the impacts on the primary energy consumption are minor. Less energy is required for oil extraction, upgrading and transportation of crude oil, but a portion of this decline is offset by an increase of energy uses for natural gas production, another resource largely available in Canada especially with the tight and shale gas.

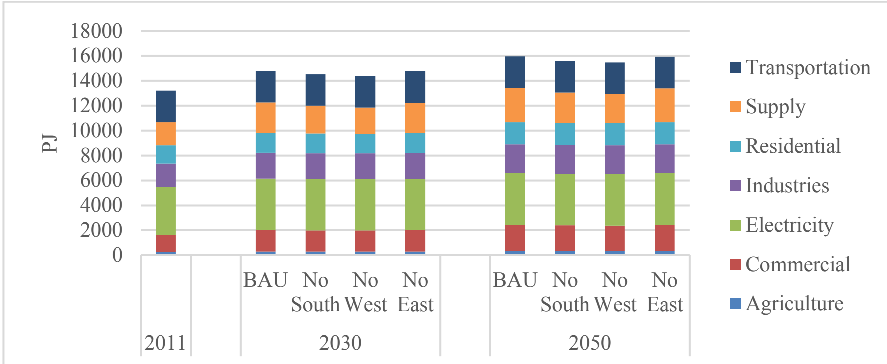

Figure 24. Primary energy consumption by sector in all scenarios

The origin of crude oil used in the Central and Eastern regions of Canada (Fig. 25) indicates a strong trend toward the replacement of international light crude oil with domestic synthetic crude through the reversed Enbridge Line 9 and the TransCanada Energy East pipeline. The No East scenario shows that the high dependence Central and Eastern provinces would have to maintain imports from global markets, a situation with many energy security concerns. Only domestic supply is limited to the imports of WCSB bitumen and synthetic crude in Ontario through the existing pipeline network. In all scenarios, the need for crude oil is decreasing significantly toward 2050 due to two main factors: 1) a larger diversification of fuel used in transportation as well as important energy efficiency improvements for the various types of vehicles, and 2) an important decline in the exports of offshore oil from Newfoundland & Labrador to the USA.

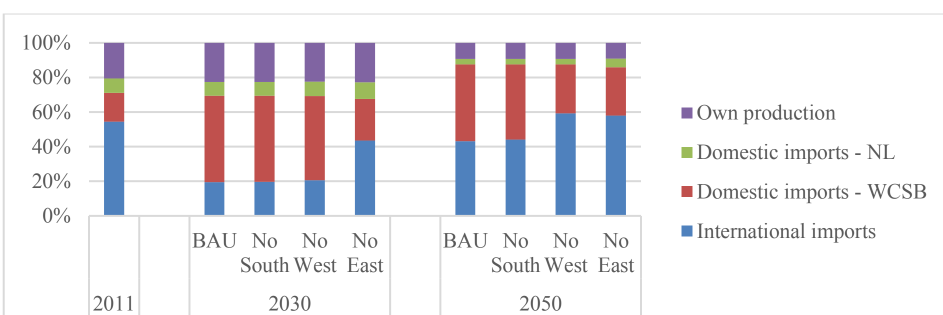

Figure 25. Crude oil supply by origin in Central and Eastern Canada in all scenarios

In the BAU scenario, the level of GHG emissions reaches 704 Mt CO2-eq in 2050. Due to changes in the primary energy consumption patterns, GHG emissions are lower in the scenarios where the exporting capacity is limited: 686 Mt CO2-eq in the No South scenario (a 2.5% reduction from the BAU level) and 673 Mt CO2-eq in the No West (a 4.4% reduction from BAU). The variations in GHG emissions are more significant than the variations in primary energy due to the fact that oil sands production is more energy intensive than natural gas production.

3.6 Discussion

It is interesting to see how these oil projections compare with official Canadian outlooks. Fig. 26 displays the oil production in all scenarios until 2035: oil production stabilizes at 9,691 PJ in 2035 in the most conservative scenario (No West) and to 12,014 PJ in the most optimistic scenario with all pipeline projects (BAU). In all cases, these production levels are conservative compared with the central and high scenarios of the NEB (2013), where oil production reaches up to 13,201 PJ (NEB–Med) and 14,806 PJ (NEB-High) in 2035 respectively and with the scenario of the Canadian Association of Petroleum Producers (CAPP) (CAPP, 2014b). These outlooks build on an optimistic view about the global demand for Canadian unconventional oil and the corresponding infrastructure capacity necessary to supply global markets: not only the available options (pipelines and/or other means) should include all projects already proposed but additional ones equivalent to the Enbridge Northern Gateway project for the NEB-Med scenario and to both Enbridge Northern Gateway and TransCanada Keystone XL projects in the NEB-High scenario.

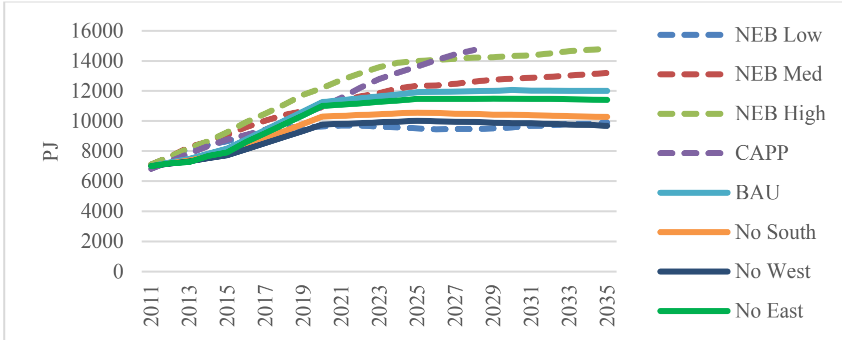

Figure 26. Oil production levels compared with Canadian outlooks

These projections could appear as rather optimistic in the face of the many uncertainties surrounding the development of some pipeline projects that have the highest potential for increasing the exporting capacity. For instance, the TransCanada Keystone XL is currently facing vivid political opposition in the USA, augmenting the project's uncertainty.

3.7 Conclusion

We have presented the oil sector of a multi-regional TIMES energy model for Canada, a bottom-up optimization model that represents, in details, the whole integrated energy system from primary to useful energy in all provinces. We have also defined different exportation scenarios based on existing pipeline capacity expansion proposals and new projects taking off from the WCSB to reach North American and Asian markets. For corresponding maximum levels of conventional and unconventional oil exports, we have compared both the impacts on the crude oil production profiles and on final energy consumption mix. Results show that the exporting capacity will be an important driver for oil production level in Canada. Outside the oil sector, impacts on the energy system are limited. In particular, final energy consumption patterns are similar across scenarios since fossil fuels remain the basis for the economy whatever the origin of crude oil.

If Western oil producers are experiencing uncertainty as per which market they will be able to occupy, and by when, what is certain is that, default by them and the interested governments to find new avenue to a fast growing production will result in lower price for Canadian oil and postpone major investments and expected financial development.

Variation of oil prices on international markets have indeed major impacts on the Canadian oil sectors in addition to pipeline capacities. Future works will study the impacts of different oil price forecasts on the Canadian energy system.

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Chapter 4
Impact of the Energy East pipeline on the oil and gas industry in Newfoundland and Labrador

Final report. Prepared for Collaborative Applied Research in Economics (CARE) initiative, Memorial University of Newfoundland.

Prepared by ESMIA Consultants, November 17th, 2015

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Abstract

It is expected that, by 2030, Canada will produce a total of 6.4 million bbl/d, with over 90% of this increase coming from bitumen (CAPP, 2014b). However, to achieve the forecasted production levels, producers of Western Canadian oil must find a market that will yield a reasonable price for their product. Eastern Canada and USA regions are one of these potential markets. The objective of this study is to develop a soft-linking model framework and demonstrate its potential application with preliminary analyses on the domestic oil supply-demand dynamic in Canada under three economic growth scenarios and the impacts of the TransCanada Energy East pipeline on the oil supply-demand

dynamic in Eastern provinces, Newfoundland and Labrador especially. The soft-linking framework combines three complementary modeling techniques: 1) the macroeconomic model NALEM (Newfoundland and Labrador Econometric Model), 2) a forecasting model of the oil production profile and, 3) the optimization LP energy model NATEM (North American TIMES Energy Model).

The results of the optimization model suggest that the pipeline would be used at its maximum capacity (1100 k bbl/d) starting around 2030 for both international exports and domestic uses in Eastern refineries, representing up to 98% of the crude used in Newfoundland and Labrador. While the oil prices are reaching 128$/bbl by 2050 in this case, blocking the access to WCSB oil in Newfoundland and Labrador brings the offshore oil price up by 10$/bbl in 2035 and 4$/bbl in 2050. The results of the forecasting model show higher production levels between 5% and 14% on average for the 2013-2050 period using these oil prices compared with those of the National Energy Board. The results illustrate well the potential of the model framework to analyse such supply-demand dynamics; this is a first step toward a broader and deeper analysis.

Executive summary

The oil industry plays a major role in the Canadian economy with over $69 billion of private investment in 2013 and generates over $18 billion for governments in taxes and revenues (CAPP, 2014a). In 2013, Canada's crude oil production reached about 3.5 million barrel/day (bbl/d). It is expected that, by 2030, the country will produce a total of 6.4 million bbl/d, with over 90% of this increase coming from bitumen (CAPP, 2014b). However, to achieve the forecasted production levels, producers of Western Canadian oil must find a market that will yield a reasonable price for their product. This report focuses on one of the markets considered to enable a significant increase in oil production: Eastern Canada and USA. Two pipeline projects are key to open these markets, the Enbridge Line 9 A and B reversal, and the TransCanada Energy East Pipeline. They would add respectively 300,000 bbl/d and 1 million bbl/d of capacity.

The objective of this study is to develop a soft-linking model framework and demonstrate its potential application with preliminary analyses on: 1) the domestic oil supply-demand dynamic in Canada under different economic growth scenarios; and 2) the impacts of the TransCanada Energy East pipeline on the oil supply-demand dynamic in Eastern provinces, Newfoundland and Labrador especially.

To analyze the interactions between oil supply and demand on a 2050 time horizon, a soft-linking framework, mixing three complementary modeling techniques, is proposed:

- The macroeconomic model NALEM (Newfoundland and Labrador Econometric Model) is a macroeconomic model representing the structure of the provincial economy and capturing the major relationships between socioeconomic variables (Department of Finance, 2015).

- A forecasting model is used to define a production profile for the Newfoundland and Labrador oil sector to 2050 by considering both economic variables (prices) and physical variables (production and infrastructure) and by establishing a link between well count, oil price, and oil production (Alcocer et al., 2015).

- The optimization LP energy model NATEM (North American TIMES Energy Model) was developed using the MARKAL/TIMES model generator (ETSAP, 2015; Loulou et al., 2005). NATEM-Canada is a technology-rich model that represents, in details, the whole integrated energy sector of the 13 Canadian jurisdictions from primary to useful energy. The oil sector is described in great details for reserves, extraction, upgrading and refining activities.

The work requires the following main steps: 1) Prepare three baseline scenarios with the NALEM model; 2) Derive reserves and oil production profiles for Newfoundland and Labrador using the forecasting model; 3) Project the end-use demand for energy services in the NATEM model using the macroeconomic drivers coming from NALEM; 4) Calibrate the NATEM model with offshore oil production profiles for Newfoundland and Labrador coming from the forecasting model; 5) Run the NATEM model for the three baseline scenarios and four scenarios on pipeline capacity; 6) Run the forecasting model back with the new oil prices as given by NATEM to derive convergence on oil production levels.

There are three baseline scenarios (CENTRAL, HIGH, LOW) and four pipeline capacity scenarios to supply the Western Canadian Sedimentary Basin (WCSB) oil to Eastern provinces (S1, S2, S3, S4). The three baseline scenarios utilize three coherent sets of oil prices and socio-economic growth rates coming from official sources (NEB, 2013), in general, and from the NALEM model for Newfoundland and Labrador, in particular. These scenarios are characterized by a WTI oil price reaching 123$/bbl (US$2012) by 2050 in the CENTRAL scenario, 147$/bbl in the HIGH scenario and 87$/bbl in the LOW scenario. The same sets of oil prices were used to derive the oil production profiles with the forecasting model. These four scenarios utilize different assumptions about the pipeline capacity available to supply the Western Canadian Sedimentary Basin (WCSB) oil to Eastern provinces:

- S1: The maximum capacity is available up to Quebec and New Brunswick/Nova Scotia (domestic refineries and international exports) and then up to Newfoundland and Labrador via marine tankers.

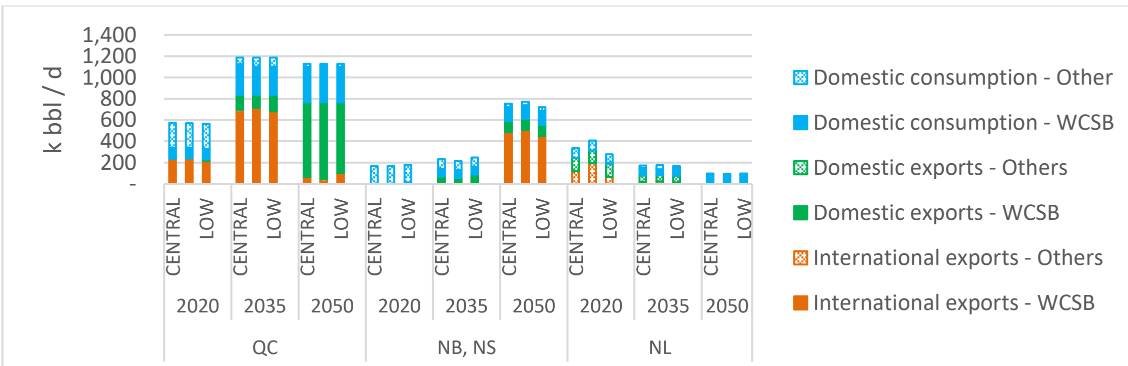
- S2: The maximum capacity is available for Quebec, New Brunswick/Nova Scotia (domestic refineries and international exports), but not for Newfoundland and Labrador.

- S3: The maximum capacity is available for Quebec, New Brunswick/Nova Scotia (domestic refineries only), leaving more access to the WCSB oil for Newfoundland and Labrador.

- S4: The TransCanada pipeline project would be cancelled, which would preclude WCSB oil from reaching domestic refineries in Eastern Canada or international markets from Eastern provinces.

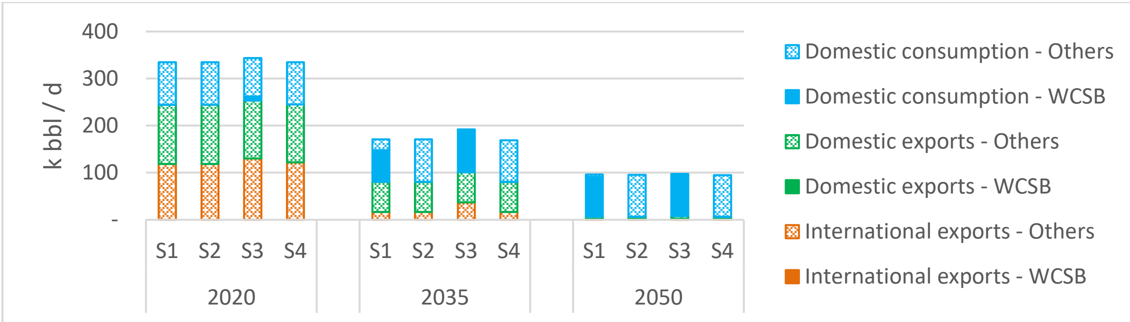
In S1, oil imports from the WCSB start as soon as the TransCanada pipeline becomes available in 2020 and reach its maximum capacity (1100 k bbl/d) around 2030. Synthetic oil is replacing a significant portion of the imported crude oil used in Quebec's refineries: between 75-82% in 2035 and 92% in 2050 (Figure ES-1). Since the needs of the province are small compared with the size of the TransCanada East pipeline, the vast majority of the synthetic oil coming through is exported to the USA toward 2035. An interesting change occurring between 2035 and 2050 is related to the destination of the WCSB oil: direct exports from Quebec to USA toward 2035 are decreasing to the profit of domestic exports to New Brunswick and Nova Scotia for international exports to Rest of the World – East where the oil prices are expected to be higher. In Newfoundland and Labrador, the synthetic oil from the WCSB is replacing the majority of the offshore oil in the refinery (between 90% and 98% by 2050). The offshore production is mainly exported on international markets.

Figure ES-1. Oil demand by province in Eastern Canada in S1



In S2, when Newfoundland and Labrador does not have access to synthetic oil, more of this oil is available for domestic use in Quebec and New Brunswick. The impact results in Newfoundland and Labrador being a greater user of its own domestic production for refining to the detriment of international exports (Figure ES-2). The limitation of international exports in Quebec and New Brunswick in S3, promotes a larger use of synthetic oil in domestic refineries in all provinces. Newfoundland and Labrador can increase its refining activities, its exports of refined products as well as international exports of its offshore oil. However, this has much less effect on the trade movement between Western and Eastern Canada than the international demand for WCSB oil. The effects of having less access to WCSB oil in Eastern Canada in S4 is clearly a decrease in activities both domestically and internationally. Interestingly, the impacts on the total production levels in the WCSB is light as more synthetic is exported directly to the USA.

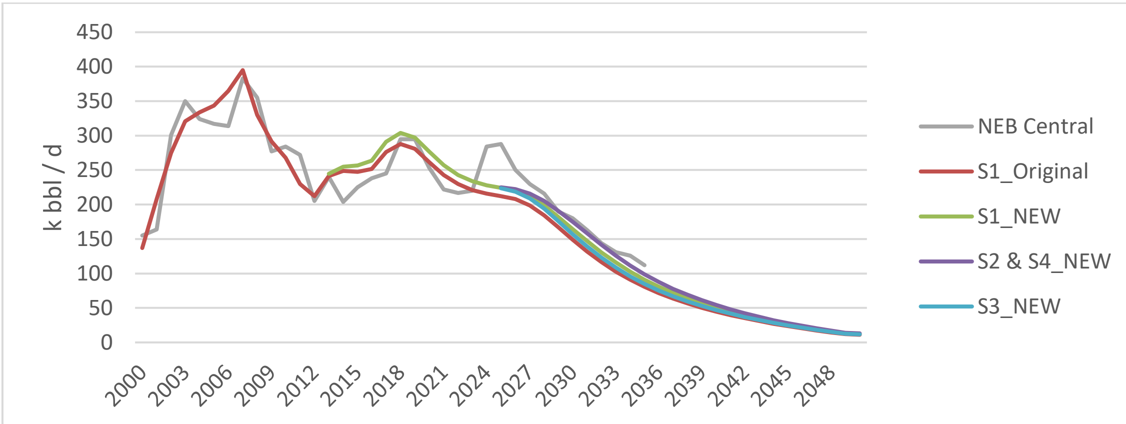
Figure ES-2. Oil demand in Newfoundland and Labrador in S1, S2, S3 and S4



In S1, there is more competition between different crude types and oil prices are converging at 128$/bbl by 2050 in all three baselines. Blocking the access to WCSB oil in Newfoundland and Labrador, such as in S2 and S4, brings the offshore oil price up by 10$/bbl in 2035 and 4$/bbl in 2050. In S3, the prices are going down by 8$/bbl in 2050 with an excess of WCSB oil coming to Newfoundland and Labrador.

After the first iteration with the forecasting model, the oil production is higher (S1_NEW) than in the original profile (S1_Original) due to higher marginal prices in the NATEM scenarios than in the central case of the NEB (Figure ES-3). The oil production difference peaks in 2036, showing a 13% higher level. In addition, S1 shows 8% more available reserves in 2013 due to the incentive of higher oil prices. Indeed, this new pattern in higher oil prices creates an incentive to drill more wells when the field oil production profile is higher compared to the original case. The impact is more significant up to 2030, since the contribution of each well is higher when the field is younger. The S2 scenario leads to the biggest benefits in terms of offshore production since there is no competition with Western oil: the oil production difference peaks in 2034, showing up to a 23% increase in production. For S3, the highest difference occurs in 2032, at 6% higher than the NEB.

Figure ES-3. Oil production in Newfoundland and Labrador after an iteration with the forecasting model



The results discussed in the report illustrate well the potential of the model framework to analyse such supply-demand dynamics and to provide insights on market trends. This is a first step toward a broader and deeper analysis. Future works will allow to improve this analysis from several points of view: 1) extend the methodology to cover more aspects of the problem and to improve the representation of the oil sector in the NATEM model, 2) refine data and assumptions to bring the definition of the problem closer to the reality and 3) consider multiple scenarios to analyse the problem in all its dimensions.

4.1 Introduction

4.1.1 Context

The oil industry plays a major role in the Canadian economy with over $69 billion of private investment in 2013 and generates over $18 billion for governments in taxes and revenues (CAPP, 2014a). In 2013, Canada's crude oil production reached about of 3.5 million barrel/day (bbl/d), of which 1.9 were produced from oil sands. It is expected that by 2030, the country will produce a total of 6.4 million bbl/d. The crude oil coming from bitumen will represent over 90% of this increase (CAPP, 2014b). Although new technologies improve the actual life expectancy of conventional oil reserves, most of the growth in oil production levels in Canada is related to oil sands. Indeed, oil sands represented 90% of 339 billion barrels (bbl) of crude oil resources by the end of 2012

(NEB, 2013). All of Canada's bitumen resources can be found in Alberta and Saskatchewan. Canada owns the third-largest reserves of oil in the world, just after Saudi Arabia and Venezuela (NEB, 2013).

However, to achieve the forecasted production levels, producers of Western Canadian oil must find a market that will yield a reasonable price for their product. Without access to tidewater ports, Alberta and Saskatchewan need to develop their transportation capacity to export this expected production. It is now becoming a political, economic and national security matter that this oil finds access to tidewater and export opportunities (McKenna, 2013)[1]. As for their actual markets, maintenance on existing pipelines and the necessity of upgrading refineries to process this crude oil from Western Canada, create bottlenecks upstream of Cushing that furthermore puts pressure on expected growth. This surplus and the inability to reach external markets already have negative effects on oil prices for Western Canadian producers. From 2007 to 2010, the Western Canadian Select (WCS), the price reference for Canadian heavy crude, traded US$16.64/bbl below West Texas Intermediate (WTI) (NEB, 2013). This price differential used to reflect the difference in the transportation costs of shipping and in quality between the two products, WCS been more corrosive and requiring additive and dilution in order to be transported. However, this gap in prices augmented to US$19/bbl between 2011 and 2012 with a high volatility: up to US$30/bbl of differential for some monthly average (NEB, 2013).

According to all projections (NEB, 2013, CAPP, 2014b), it is expected that production will soon exceed current pipeline capacity and only long-term solutions may help supporting this projected growth. In the short term, transportation by rail cars may provide a temporary solution. In fact, rail cars shipping is expected to increase in Canada from about 200,000 bbl/d in late 2013 to 700,000 bbl/d by the end of 2016 (CAPP, 2014c). This is about the capacity of a major pipeline. However, even with this rapid expansion, the incremental capacity to export via rail cars will not be sufficient in the long term; there must be a dramatic increase in export capacity. In summary, it is necessary for Western Canada to find and open new markets to enable a significant increase in oil production. In

[1] This is even more critical considering that the Keystone XL pipeline has been declined permission by the Obama administration to proceed within the United States (Plumer, 2015).

this study, three markets are therefore considered for analysis: 1) Central and South USA markets, 2) Canadian and USA West coasts and Asia, and 3) East Canada and Eastern USA.

4.1.2 Objectives

This research builds on a previous study (Vaillancourt et al., 2015), which focuses on different crude oil exportation scenarios based on existing capacity expansion and new pipeline projects exiting the Western Canadian Sedimentary Basin (WCSB) to reach North American, Asian or domestic markets. This report focuses specifically on the impact of the Energy East TransCanada pipeline on the oil and gas industry in Newfoundland and Labrador.

Indeed, Western producers are considering new markets on the other side of the country among others. Refineries in Québec and the Atlantic Provinces import more than 80% of their crude oil (642,000 bbl/d) from international markets, which makes them perfect targets for the expanding production in Western Canada. Supplying East refineries with Western crude will contribute to the country's energy security. These regions' four refineries can start using synthetic oil or handling blends with heavier crude without much modification to their installation. Their products could therefore be exported to Eastern USA. There is the additional advantage of an existing, but incomplete, network of pipelines that could be used to transport large amounts of crude to these regions. In Ontario, the refineries processed 380,300 bbl/d of crude oil from Canadian producers (representing 94% of capacity) in 2013. The first phase of the Enbridge Line 9 reversal is facilitating this internal transportation. PADD I district[2] is also a potential market that, if reached, may want to change its international imports to a more local and secure supply. Two pipeline projects are key to open these new markets, the Enbridge Line 9 A and B reversal, and the TransCanada Energy East Pipeline. If they were to be accepted in their

[2] In the United States, the Petroleum Administration for Defense Districts (PADDs) are geographic aggregations of States that allows regional analysis of crude oil and oil products supply and movements. PADD 1 is the East Coast.

actual form, they would add respectively 300,000 bbl/d and 1 million bbl/d to Québec's and Atlantic refineries.

Consequently, the main objective of this work is to develop a soft-linking model framework and to demonstrate its potential application with preliminary analyses on: 1) the domestic oil supply-demand dynamic in Canada under different economic growth scenarios; and 2) the impacts of different pipeline projects on the oil supply-demand dynamic in Eastern provinces, Newfoundland and Labrador especially. It is important to mention that the focus of this work has been on developing the framework using recent data as well as a coherent sets of assumptions. However, although the potential application of the proposed framework was successfully demonstrated to analyse oil demand and supply dynamics, we do not pretend to bring final answers to these issues. Indeed, a thorough review of the main data and assumptions, their validation with key players in the industries, as well as a deeper analysis of results would be necessary to bring robust solutions to these issues.

This paper is organized as follows. Section 4.2 gives an overview of the soft-linking framework using three models that are proposed to assess the oil supply-demand dynamics under different economic growth scenarios and different pipeline capacity scenarios for supplying Canadian oil to Eastern provinces. Section 4.3 details the scenario definition. Section 4.4 contains the analysis of all scenarios, namely the impacts for Eastern provinces of having a larger access to Western oil in terms of oil prices and offshore production, international and domestic trade movements. In Section 4.5, we conclude on the main outcomes of the study.

4.2 Methodology

4.2.1 General framework

To analyze the interactions between oil supply and demand, a soft-linking framework, mixing three complementary modeling techniques is proposed. These include macroeconomic, forecasting and optimization (Figure 27).

- The macroeconomic model NALEM (Newfoundland and Labrador Econometric Model) is a macroeconomic model representing the structure of the provincial economy and capturing the major relationships between socioeconomic variables. In addition, NALEM is able to capture and quantify the impacts of structural changes such new programs, tax reforms, evolution of the oil and gas industry, etc. "NALEM is organized into 10 different sectors: consumer spending, residential construction, business investment, government spending, exports, and imports comprise the six expenditure sectors essential to the determination of GDP and other key economic indicators. The remaining four sectors cover income and output, demographic and labour market activity, prices and wages, and government revenue. NALEM produces annual forecasts of all main indicators of provincial economic activity including GDP, personal income, labour force, employment, Consumer Price Index (CPI), and population." (Department of Finance, 2015).

- A Forecasting model is used to define a production profile for the Newfoundland and Labrador oil sector to 2050. The model considers both economic variables (prices) and physical variables (production and infrastructure) by establishing a link between well count, oil price, and oil production (Alcocer et al., 2015). Indeed, the well count is used in the oil industry as a key component of planning and decision-making in matters such as capital and operational expenditures. The approach is combined with the Hubbert logistic function to take into account the impact of the age of the producing wells. Calibration is done using a Canadian database of historical production data and records come from numerous Eastern Canada offshore and Canadian oil sands projects.

- The optimization LP model NATEM (North American TIMES Energy Model) is an energy model that has been developed using the most advanced energy optimization modeling framework: The Integrated MARKAL-EFOM System (TIMES). The MARKAL/TIMES model generators are supported by the Energy Technology Systems Analysis Program (ETSAP, 2015) of the International Energy Agency (IEA) and are currently used by more than 80 institutions in nearly 70 countries. This is a technology-rich optimization model that represents, in details, the whole integrated energy sector of Canada from primary to useful energy.

The work requires the following main preparation steps, namely data work, model settings, calibration and linking:

- Prepare three baseline scenarios. This task requires the preparation of three different baselines scenarios using the NALEM model, i.e. three different storylines consistent in terms of projections for oil prices as well as macroeconomic drivers (GDP, population, etc.). These projections will be used as drivers in both the forecasting and the energy optimization NATEM models. This model will help to understand the impact of variations in oil prices on provincial GDP.

- Derive reserves and oil production profiles (conventional and non-conventional) for Newfoundland and Labrador using the forecasting model. This task involves reviewing and updating reserves and oil production figures for Eastern offshore Canada.

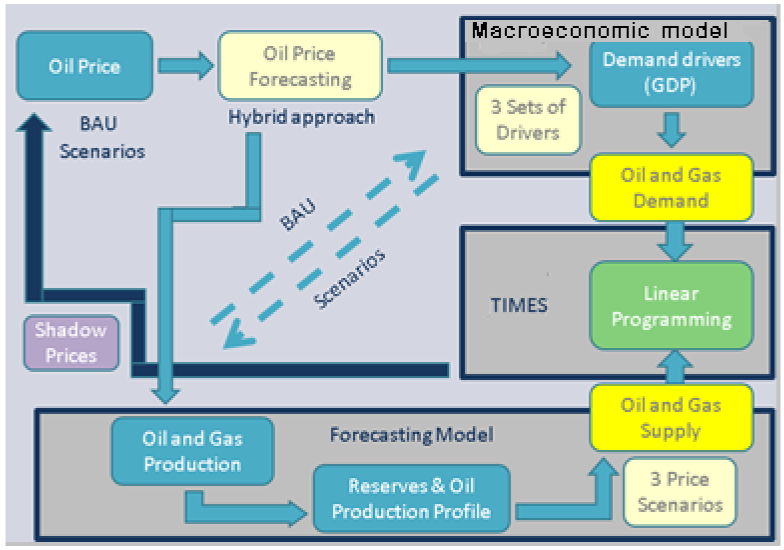
- Project the end-use demand for energy services in the NATEM model using the macroeconomic drivers coming from the NALEM model.

- Calibrate the NATEM model with offshore oil production profiles for Newfoundland and Labrador coming from the forecasting model.

- Run the NATEM model for the three different baseline scenarios and analyzing alternate scenarios on pipeline capacity bringing more or less oil from Western Canada to Newfoundland and Labrador. For each scenario, the model will provide optimal technology and fuel mix to meet the end-use demand for energy services as well as partial supply-demand equilibrium. The NATEM model is used to study the relation between oil prices and quantities between the West and East Canadian coasts.

- Run the forecasting model back with the new oil prices as given by NATEM in the different pipeline capacity scenarios and performing iterations to derive convergence on oil production levels.

Figure 27. Soft-linking three models



While the macroeconomic NALEM model was developed by the Department of Finance of the Government of Newfoundland and Labrador, both the NATEM optimization energy model and the oil forecasting models are developed and managed among our team. Consequently, more details are provided regarding the structure and the assumptions behind these two models; the NATEM model is described in Section 4.2.2 and the forecasting model is described in Section 4.2.3.

4.2.2 The NATEM model

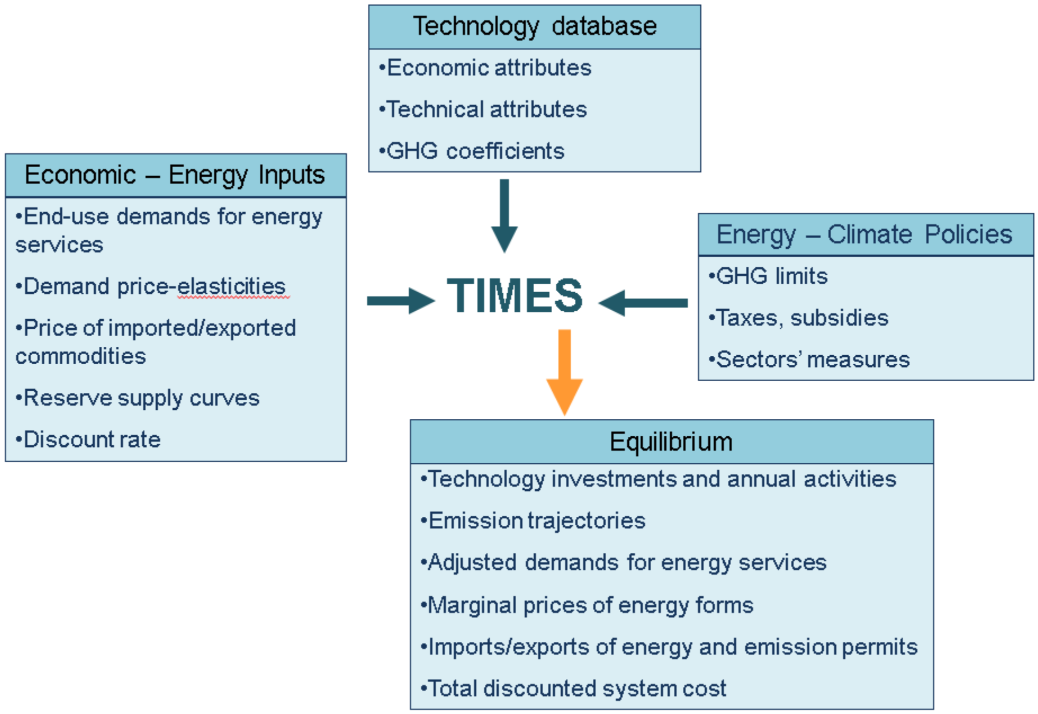
It is worth providing more information on the modeling philosophy and the economic rational of TIMES model, in general, as well as on the database structure of NATEM-Canada, in particular, in order to better understand the meaning of the results presented in this report.

4.2.2.1 The TIMES model generator

The TIMES model generator combines all the advanced features of the MARKAL models (Fishbone and Abilock, 1981) and to a lesser extent the ones of the EFOM (Energy Flow Optimization Model) model (Van der Voort, 1982), as well as various new features developed over time (Loulou et al., 2005). A TIMES model represents the entire energy system of a country or region. Such a system typically includes extraction, transformation, distribution, end-uses, and trade of various energy forms and materials. Each stage is described by means of specific technologies characterized by economic and technological parameters. The model also tracks GHG and criteria air contaminant emissions from fuel combustion and processes. In baseline scenarios, end-use demands are exogenously specified in terms of socio-economic needs (e.g., transportation, expressed in vehicle-kilometres) over a future horizon. A TIMES model is cast as a dynamic linear programming model. Under the assumption that energy markets are under perfect competition, a single optimization, which searches for the maximal net total surplus, simulates market equilibrium. Maximizing the net total surplus (i.e. the sum of producers' and consumers' surpluses) is operationally done by minimizing the net total cost of the energy system that includes investment costs, operation and maintenance costs, plus the costs of imported fuels, minus the incomes of exported fuels, minus the residual value of technologies at the end of the model horizon, plus welfare losses due to endogenous demand reductions. The main model outputs are future investments and activities of technologies at each period of time. Important additional outputs of the model are the implicit price (shadow price) of each energy material and emission commodity, as well as the reduced cost of each technology (i.e. reduction required to make a technology competitive).

In addition, TIMES models acknowledge that demands are elastic to their own prices contrary to traditional bottom-up models. This feature makes possible the endogenous variation of demands in policy scenarios compared to the baseline, thus capturing the vast majority of structural changes in demands and their impacts on the energy system. In climate policy scenarios, emission reduction is brought about by technology and fuel substitutions, which lead to efficiency improvements and process changes, by carbon capture and sequestration and by endogenous demand reductions. Figure 28 gives a schematic view of the main inputs and outputs associated with TIMES models.

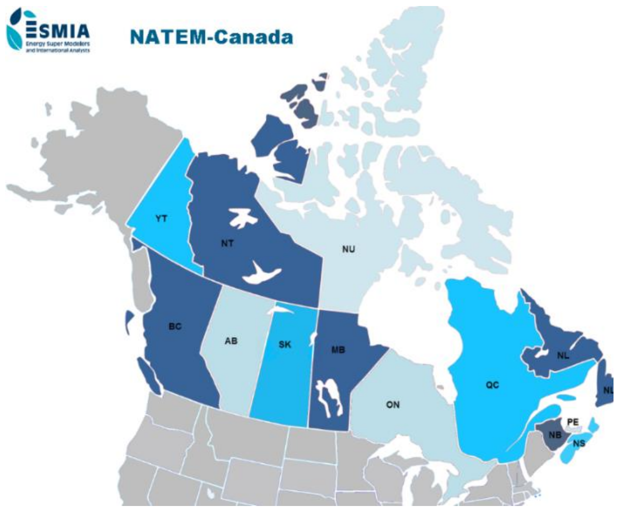
Figure 28. Schematic view of information flows in TIMES models



4.2.2.2 The NATEM-Canada database

The model covers the energy system of the 13 Canadian provinces and territories which are grouped into four main geographical regions for reporting purposes (Figure 29). The model spans 90 years (2011 to 2100) and this study will cover the 2011-2050 time frame through nine time periods. For each period, 16 time slices are defined uniformly across Canada, with four seasons a year (spring, summer, fall and winter) and four intraday periods (day, night, morning peak, evening peak). All costs are in 2011 Canadian dollars ($). The global annual discount rate has been set to 5% for this study; additional works would be relevant to assess the impact of different discount rates on the evolution of the Canadian energy system.

Figure 29. Provinces and Territories of Canada



Code	Province/Territory	Region
AB	Alberta	West
BC	British Colombia	West
MB	Manitoba	West
NB	New Brunswick	East
NL	Newfoundland	East
NS	Nova Scotia	East
NT	Northwest territories	North
NU	Nunavut	North
ON	Ontario	Central
PE	Prince Edward Island	East
QC	Quebec	Central
SK	Saskatchewan	West
YT	Yukon	North

**THE MODEL REGION CODES CORRESPOND TO THE ISO*

Overall, the model database includes more than 4,500 specific technologies and 800 commodities in each province and territory, logically interrelated in a reference energy system (Figure 30).

Final energy consumption. The model is driven by a set of 70 end-use demands for energy services in five sectors: agriculture (AGR), commercial (COM), industrial (IND), residential (RSD) and transportation (TRA). In each sector and module of the database, a repository includes a large number of new technologies that are in competition to satisfy each end-use demand, including existing technologies, improved versions of existing technologies, as well as new technologies.

Conversion to secondary energy. This covers all energy conversion technologies such as power plants (thermal with and without carbon capture options, nuclear, renewables, etc.), fossil fuels transformation plants (refineries, coke plants) and biofuels/biomass plants. There are separate modules for a potential future hydrogen economy and liquefied natural gas (LNG) industry.

Primary energy supply. The database compiles all Canadian primary energy sources, such as both conventional and unconventional fossil fuels reserves (oil, gas, coal), renewables potentials (hydro, geothermal, wind, solar, tidal and wave), uranium reserves and biomass (various solid, liquid and gaseous sources).

Energy trade. All primary and secondary forms of energy can be traded within and outside Canada. The domestic trade module deals with energy exchanges between the Canadian provinces and territories. The international trade module covers all energy exchanges between Canada and other countries, including USA.

GHG emissions. The model tracks carbon dioxide (CO2), methane (CH4) and nitrous oxide (N2O) emissions from fuel combustion, fugitive emissions (from processes, flaring and venting) from the energy sector as well as process emissions from the agriculture sector.

Carbon capture and sequestration. Capture options are available in the electricity sector for the new coal plants. Future works will allow the addition of carbon capture options with biomass power plants. In addition to the regular emission reduction options available in the model (technology and fuel substitutions, endogenous demand reductions), a module is also covering sequestration potentials for various options, including: enhanced oil recovery, enhanced coal bed methane, afforestation, oil and gas fields (onshore and offshore), deep saline aquifers.

As a result of our calibration process, the model yields for 2011 energy production and consumption consistent with official statistics (NEB, 2013; Statistics Canada, 2011; 2012; OEE 2011; Environment Canada, 2013) for the different province and territories.

In particular, Figure 31 gives a simplified representation of the oil sector in the model.

Reserves. Supply curves have been built from the latest data available from NEB (2013) and CAPP (2013) for the different types of oil (conventional light, tight, heavy and non-conventional bitumen), reserves (located reserves, enhanced recoveries and new discoveries) and extraction techniques (mined and in situ). Most of the Canadian oil reserves (93%) are located in the WCSB spread in four main provinces (Alberta, Saskatchewan, British Columbia, Manitoba).

Extraction. Extraction technologies are modeled for each type of oil and reserves. In particular, there are different technologies for bitumen extraction from either mined or in situ methods. While most of the bitumen have been extracted from mining techniques (e.g. the truck and shovel approach), the use of in situ processes is expected to growth considerably in the future as only a minor portion of the bitumen reserves are closed to the surface. Finally, two different technologies for in situ extraction: the first method called cyclic steam stimulation (CSS) and a more recent method steam assisted gravity drainage (SAGD). Both technologies use injection of steam into oil-sands deposits to reduce its viscosity and allow the bitumen to be moved to the well, but the SAGD method allow a better oil recovery factor and a better steam to oil ratio. Most of the mined bitumen (95%) is currently upgraded into synthetic oil, while the in situ bitumen is mixed with condensates to produce a diluted bitumen appropriate for transport by pipeline. All these technologies are characterized by different costs and energy requirements.

Figure 30. Simplified representation of the reference energy system of each Canadian jurisdiction

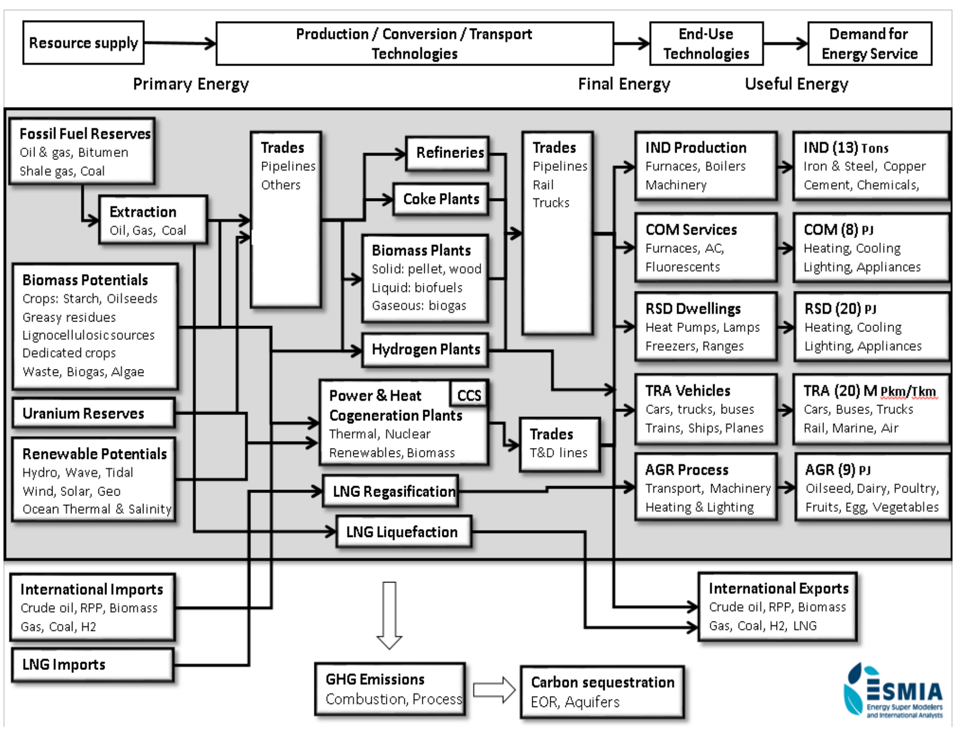
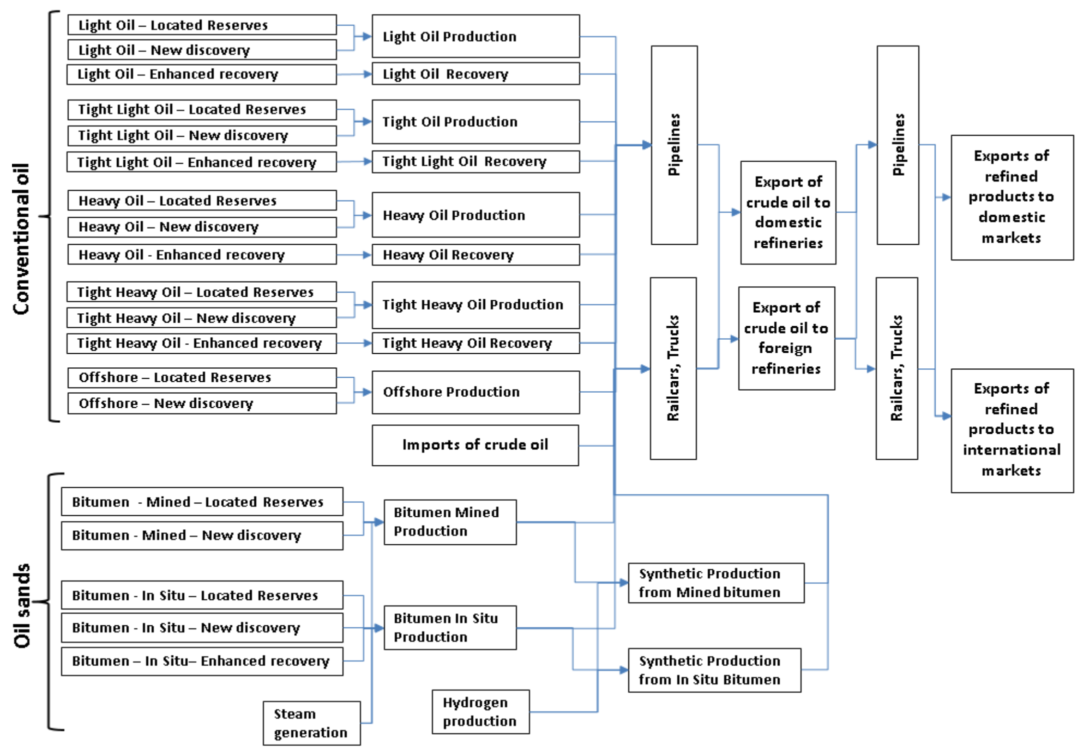


Figure 31. Simplified representation of the oil supply sector



Exploration and development costs are shown in Table 6. The costs vary with the oil types as their exploration is associated with different levels and require different technologies for their development, but are assumed to be constant in time. The variation in costs in the WCSB (min-max) is related to the location of wells: costs are normally lower in Alberta than in the rest of the region. Table 7 contains the annual well maintenance and operation costs by type of oil and extraction methods (CERI 2013a; 2013b). Costs decrease at a yearly rate of 0.075% until 2035 (CERI 2011) and stay constant thereafter.

Table 6. Exploration and development costs for conventional and unconventional oil

2011 $ / bbl	WCSB-Min	WCSB-Max	Offshore East	Northern Territories
Conventional light				
Light crude oil located reserves	12.57	29.11		47.25
Light crude oil enhanced recovery	18.76	35.30		53.45
Light crude oil new discovery (step 1)	24.96	41.49		59.64
Light tight oil located reserves	18.76	35.30		

2011 $ / bbl	WCSB-Min	WCSB-Max	Offshore East	Northern Territories
Conventional heavy				
Heavy crude oil located reserves	15.54	22.42		
Heavy crude oil enhanced recovery (step 1)	21.74	28.61		
Heavy crude oil new discovery (step 1)	27.93	34.80		
Heavy tight oil located reserves	21.74	28.61		
Offshore				
Offshore oil located reserves			29.42	47.25
Offshore oil new discovery			41.80	59.64
Unconventional – Oil sands				
Mined bitumen located reserves	23.04			
Mined bitumen new discovery	29.23			
In situ bitumen located reserves	25.27			
In situ bitumen enhanced recovery	31.46			
In situ bitumen new discovery	37.65			

Source: CERI 2013a; 2013b; expert assumptions

Table 7. Well maintenance and operation costs for conventional and unconventional oil

2011 $ / bbl	2011	2012	2013	2015	2050
Light crude oil	7.93	7.87	7.80	7.68	6.63
Light enhanced recovery	14.12	14.00	13.93	13.69	11.77
Light tight oil	14.12	14.00	13.93	13.69	11.77
Heavy crude oil	7.93	7.87	7.80	7.68	6.63
Heavy enhanced recovery	14.12	14.00	13.93	13.69	11.77
Heavy tight oil	14.12	14.00	13.93	13.69	11.77
Offshore oil	20.90	20.73	20.61	20.27	17.43
Mined bitumen	17.90	17.77	17.59	17.34	14.93
In situ bitumen	9.35	9.23	9.17	9.04	7.80
Mined bitumen with upgrading	24.59	24.40	24.21	23.84	20.50
In situ bitumen with upgrading	15.98	15.85	15.73	15.48	13.31

Source: CERI 2011; 2013a; 2013b

Upgrading and refining. Downstream activities includes six upgraders with a total capacity of 1.2 million bbl/d and 19 refineries with a total capacity of 2.06 million bbl/d and producing a full range of refined products (CAPP, 2014b). Only a small number of refineries in Ontario and Alberta are currently configured to upgrade bitumen directly. All technologies are characterized by different costs and energy requirements. An important quantity of natural gas is use for steam generation (bitumen recovery) and hydrogen production (bitumen upgrading). Corresponding GHG emissions from fuel combustion and fugitive emissions are accounted at each step of the supply chain as well as flaring and venting emissions.

Transportation. The database includes the current existing transportation capacity as well as planned projects for existing capacity expansion or new infrastructure. Due to the location of the main production centers in the WCSB and of the major markets in the USA Midwest and Gulf Coast regions, the pipeline network in North America has a strong North-South linkage. There are actually four main pipelines exiting the WCSB with a total capacity of 3.67 million bbl/d. The existing pipelines as well as planned projects are listed in Table 8 for exports from the WCSB to international destinations; they can all be visualized on maps in CAPP (2014b). In addition, rail transportation capacity has evolved quickly from 46 thousand bbl/d in 2012 to 300 thousand bbl/d in 2014 (CAPP, 2014b). The growth in rail capacity is assumed to slow down and reach a maximum of 945 thousand bbl/d day in 2050.

Table 8. Existing and proposed pipelines for international exports

Pipeline	Target In-Service	Capacity (k bbl/day)	Capacity (PJ)
Enbridge Mainline	1950	2500	5,651
Kinder Morgan Trans Mountain	1953	300	678
Spectra Express	1997	280	633
TransCanada Keystone	2010	591	1,336
Total Existing Capacity		**3,671**	**8,298**
Enbridge Alberta Clipper Expansion	2015	120	271
Enbridge Alberta Clipper Expansion	2016	230	520
TransCanada Keystone XL	2020	830	1,876
Trans Mountain Expansion	2017	590	1,334
Enbridge Northern Gateway	2017	525	1,187
Total Proposed Capacity		**2,295**	**5,188**
Total Capacity		**5,966**	**13,486**

As for domestic trade, two major new projects are proposed and they are considered as future investment options in the model (Table 9) (CAPP, 2014b). These projects would allow synthetic oil from the WCSB to be exported to Eastern refineries since they are not equipped to process bitumen. This provides an opportunity for Quebec and Atlantic provinces to reduce their imports from foreign countries. In average, the existing transportation capacity between Canadian jurisdictions are assumed to be used at 85% of their maximum capacity. This means that for export increases of more than 15% from current level required new investments in transportation capacities.

Table 9. New pipelines for domestic exports

Pipeline	Target In-Service	Capacity (k bbl/day)	Capacity (PJ)
Enbridge Line 9 reverse	2015	300	678
TransCanada Energy East	2018	1,100	2,486

The model allows increase in exportation levels in three phases: 1) until 100% of the existing capacity is reached (i.e. the least cost option) ; 2) until 100% of the committed new capacity (e.g. expansion plan) is reach by 2020; and 3) by investing in new transportation infrastructure such as pipeline and rail tracks (i.e. the highest cost option).

Cost assumptions are presented in Table 10. The total investment cost for new pipeline projects vary between 16.6$/bbl to 34.2$/bbl. For the TransCanada Energy East project in particular, the cost was estimated at 11.3 billion $ (Deloitte, 2013) or roughly 28.1 $/bbl. Due to lack of precise data in the appropriate format, the investment cost for new rail is assumed to be 75% of the new pipeline cost. For the modeling exercise, the total investment costs of building new transportation capacity was allocated to the different provinces on a distance basis from Alberta in order to adequately account for the transportation costs for each province and to capture the effect on the endogenous oil commodity prices. Similarly, although the maintenance and operation costs are constant on a barrel basis (approximately 0.7$/bbl using assumptions in Karangwa (2008); Statistics Canada 2015a; 2015b), they vary with the distance between provinces. In the model database, the maintenance and operation costs of the rail transportation mode are assumed to be higher than those of the pipeline mode, although this difference is reduced over time. The final transportation cost for Newfoundland and Labrador for the synthetic oil coming from Alberta by pipeline amount to 9.5$/bbl.

Table 10. Cost assumptions by transportation mode

$/bbl	Pipeline		Rail	
	Min	Max	Min	Max
Investment costs for new projects by province	$1.5	$3.8	$1.1	$2.8
Annual operation costs for existing and new transportation mode 2011-2019	$0.7	$4.1	$1.0	$6.1
Annual operation costs for existing and new transportation mode 2020-2050	$0.7	$4.1	$0.8	$4.9

Exports. The model captures six types of oil commodities (light oil, heavy oil, bitumen, synthetic oil, condensates and pentanes) that can be transported by pipelines and/or other means (trucks, trains and tankers) from primary production wells to different types of destinations: domestic refineries, USA refineries and export terminals (e.g. Kitimat in BC) reaching two aggregated international regions (Rest of the World – East and Rest of the World – West). While international trade movements are modeled using fix prices and limits on quantities by origins and destinations, domestic trade movements within Canada are determined endogenously (i.e. prices and quantities are determined by the model based on the available infrastructure capacities and cost of investing in new capacities).

Table 11 shows the price for exported oil (and import oil) on international markets. These prices were first based on oil price forecast given by NEB (2013) with a constant different of 7$/bbl for Brent over WTI until 2035 following assumptions: exports to USA (Brent price -5$/bbl), to ROW - West (Brent price), to ROW- East (Brent price +2$/bbl). Due to the excess of oil supply in North America and the lack of pipeline to reach demand markets, the oil prices are lower than on international markets.

Table 11. Exported oil prices by destination, 2011-2050

Destination	Unit	2012	2013	2020	2025	2030	2050
USA	$/bbl	$98	$ 97	$104	$107	$110	$115
ROW - West	$/bbl	$ 103	$102	$109	$112	$115	$120
ROW- East	$/bbl	$ 105	$104	$111	$114	$117	$122

Energy uses and emissions. All energy requirements for oil extraction, transformation and transportation is accounted in the model. In particular, an important quantity of natural gas is use for generating the steam used for bitumen extraction as well as for producing the hydrogen used for bitumen upgrading at wells or at the refineries. This natural gas consists in both purchased gas (two-third) and the co-products generated during the in situ extraction and upgrading operations. Corresponding GHG emissions from fuel combustion and fugitive emissions are accounted at each step of the supply chain as well as flaring and venting emissions from oil, gas and coal production.

4.2.3 The forecasting model

The forecasting model considers both economic variables (prices) and physical variables (production and infrastructure) by establishing a link between well count, oil price and oil production (Alcocer et al., 2015). The approach is combined with the Hubbert logistic function to take into account the impact of the age of the producing wells. The model is described in Alcocer et al., (2015) and summarized here.

Oil production. We assume that yearly production of oil ($P_{o,n}$) of a given oil type o (e.g., onshore, offshore, or oil sands) in a given field or region n is a linear function of the new investments ($I_{o,n}$) that correspond to the number of newly drilled wells (i.e., the well count); the field average production rate ($f_{o,n}$) per well; the time-indexed performance (i.e., production) for individual wells ($w_{o,n}$), which is assumed to be identical for the new wells drilled in a given year (i.e., as a vintage); and the average life ($l_{o,n}$) of the assets (i.e., wells) :

$$P_{o,n}(t) = \sum_{i=t-l_{o,n}}^{t} \left(I_{o,n}(i).f_{o,n}(i).w_{o,n}(t-i) \right) \quad (1)$$

where *t* is a (discrete) time index corresponding to the year considered. Note that the field average production rate ($f_{o,n}$) could be either a constant (i.e., average production) or a function of time for the quantity produced. In the latter case, it could account for learning effects (i.e., either improving with time or as more oil is produced). It can also represent the maturity of the oil field.

Investments in new wells. Under some (strong) microeconomic assumptions (Jukić, Scitovski, and Sabo, 2005) that define a perfect competitive market (such as perfect information, a large number of buyers and sellers, free entry and exit, homogeneous goods, perfect factor mobility, and zero transaction costs, one can postulate an upward relationship between oil price (*p*) and the production ($P_{o,n}$) at time *t*. We assume here that the new investments follow this rationale as described below:

$$I_{o,n}(t) = k_o + k_1.p(t) + k_2.P_{o,n}(t) \tag{2}$$

where k_0, k_1, and k_2 are calibration parameters.

Equations (1) and (2) are based on supplier behaviour according to specific microeconomic principles as well as practices in the oil industry. More precisely, oil-producing firms typically use an approach similar to Eq. (2) as a planning tool to help them decide what new wells to drill. In this case, the price and production levels (to be used in Eq. (2)) are based on expert estimations. We have statistically tested the correlation between oil prices and well counts for Canada; see Alcocer et al., (2015).

Production of individual wells. To predict the future oil production, we use the Hubert peak approach that uses a logistic function to explain the decline in the production of oil wells and fields over time (Hubbert, 1956). This function is based on empirical observations made by the American geophysicist M. King Hubbert as he successfully predicted the evolution of American oil production around 1965–1970. This can be expressed as follows:

$$w_{o,n}(t) = \frac{h_0 \cdot e^{-h1 \cdot t}}{(1+ \cdot e^{-h1 \cdot t})^2} \tag{3}$$

where h_0 is the maximum production that one individual oil well can achieve and h_1 is a factor describing the steep of oil production decline over time. These two parameters are adjusted to match the total production for a specific oil type and region.

Alcocer et al., (2015) also describe in details how the calibration was done for the different types of oil production (conventional onshore, offshore, and oil sands) in two

Canadian regions (Eastern and Western Canada) for the period 1980–2007. In this work, the forecasting model was used to define production profiles for the oil sector in Newfoundland and Labrador under different oil price scenarios up to 2050.

4.3 Scenarios

4.3.1 Baseline scenarios

4.3.1.1 Demand projections from NALEM drivers

TIMES models compute the optimal energy configuration that satisfies future demands for energy services that have been exogenously assumed from 2011 levels. The approach used in this work build on Vaillancourt et al., (2014) where different baselines were developed using coherent sets of growth rates, characterized by different assumptions on oil prices or economic growth. It covers a large range of uncertainties related to possible future trends. Concretely, growth rates of various socio-economic drivers up to 2050 are applied to the 2011 base year demand for energy services in NATEM, in conjunction with coefficients capturing service demand sensitivity to these drivers.

$$\boldsymbol{Demand_t} = \boldsymbol{Demand}_{\boldsymbol{t-1}} \times \left(\mathbf{1} + \left(\frac{\boldsymbol{Driver_t}}{\boldsymbol{Driver_{t-1}}} - \mathbf{1}\right) \times \boldsymbol{Sensitivity_t}\right) \qquad (4)$$

In summary, this approach requires: 1) the definition of a coherent sets of socio-economic driver growth rates for all end-use demands in all provinces and territories, 2) the allocation of a particular socio-economic driver to each end-use demand in each province and territory and 3) the definition of a sensitivity series for each drivers allocated to each end-use demand.

Similarly, we have developed three baseline scenarios, which utilize three coherent sets of oil prices and socio-economic growth rates coming from official sources (NEB, 2013), in general, and from the NALEM model for Newfoundland and Labrador, in particular; a CENTRAL scenario and two other baselines, a LOW and HIGH scenarios. Main assumptions are shown in Table 12 for Canada and Newfoundland and Labrador in terms of average annual growth rates.

Table 12. Main assumptions in the three baseline scenarios

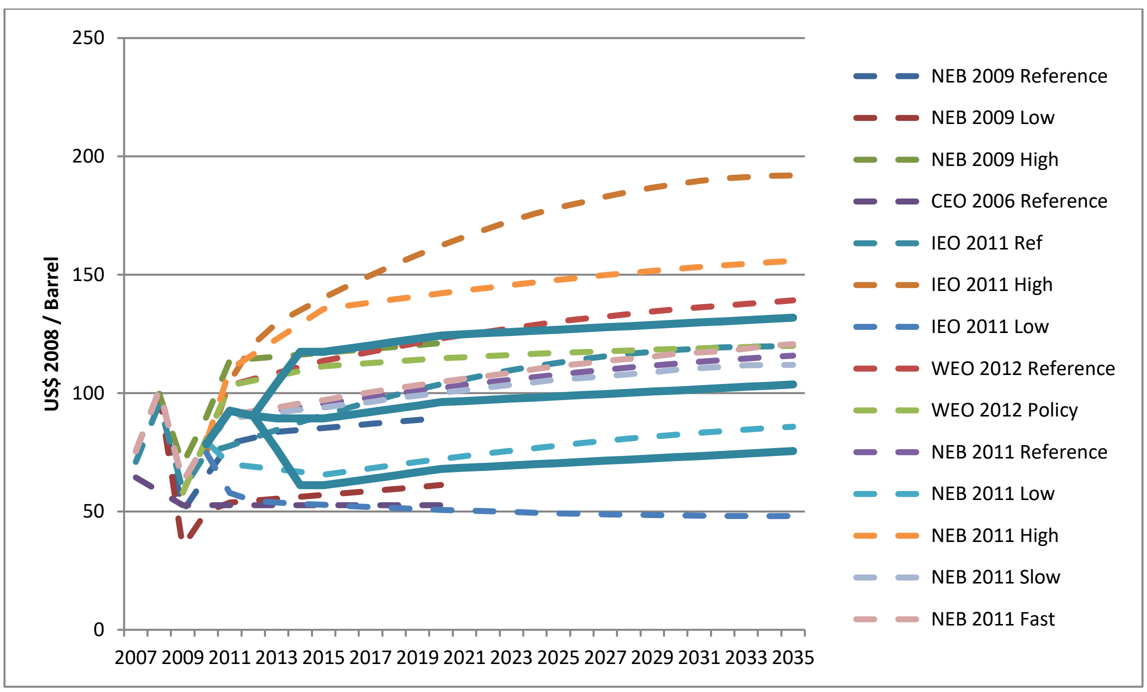
Scenario	Canada		Newfoundland and Labrador	
	2011-2035	2035-2050	2011-2035	2035-2050
Total GDP*				
Central	1.78%	1.54%	0.87%	1.01%
High	1.74%	1.70%	0.96%	0.85%
Low	1.84%	1.51%	0.79%	0.30%
Population				
Central	0.94%	0.81%	0.04%	-0.04%
High	0.94%	0.81%	0.09%	-0.13%
Low	0.94%	0.81%	-0.02%	0.05%
Household Floor Space				
Central	1.32%	1.25%	0.39%	1.04%
High	1.32%	1.25%	0.39%	1.04%
Low	1.32%	1.25%	0.39%	1.04%
Personal Disposable Income				
Central	2.30%	1.60%	3.22%	0.64%
High	2.36%	1.66%	3.43%	0.64%
Low	2.28%	1.60%	3.00%	0.64%

* Correspond to the adjusted real GDP at market prices for Newfoundland

The CENTRAL scenario is characterized by a WTI oil price starting at 96$/bbl (US$$_{2012}$) in 2011 and reaching 110$/bbl by 2035 and 123$/bbl by 2050. The oil price remains flat until 2016 and slowly increases afterward due to the assumption that strong oil demand from developing countries offset the growth in unconventional oil and gas supplies. In the LOW and HIGH cases, the oil price is assumed to be below and above the reference price by 30$/bbl in 2035. The oil price reaches 147$/bbl by 2050 in the HIGH scenario and 87$/bbl by 2050 in the LOW scenario. As for the socio-economic drivers, they come mainly from NEB (2013), but GDP, GDP per capita and population figures for Newfoundland and Labrador were adjusted based on the NALEM forecast for the three baselines between 2011 and 2035. For information purpose, Figure 32 compares the three NEB forecasts (bold lines) to those of other national and international organisations (dash lines).

A driver has been allocated to each end-use demand following a specific logic in each sector. The allocation is identical in all provinces and territories. As for sensitivity series, they were derived from past observations regarding the evolution of the end-use demands compared with the evolution of the drivers. Energy demand in different sectors is influenced by different factors. End-use demands for energy services in the residential sector (e.g. space heating) will be affected by drivers such as population and the number of households with slower growth rates, while those of the commercial sector will be affected by drivers with higher growth rates such as of the GDP for service industries or GDP per capita. In the agriculture sector however, the end-use demands are projected using the original drivers of NATEM (Frenette, 2013). This choice was motivated by the fact that these drivers result from a comprehensive study on agri-food policy and, consequently, are more detailed and more appropriate for the structure of the model.

Figure 32. Comparison of oil price forecasts from different national and international organisations



The resulting end-use demands for energy services in Newfoundland and Labrador are presented in Table 15 in Annexes for the CENTRAL scenario at milestone years. An example is provided regarding end-use demand projections for passenger transportation in million passengers-kilometres for Canada in Figure 33 and for Newfoundland and Labrador in Figure 34 in the three baselines.

Figure 33. End-use demand projections for passenger transportation in Canada

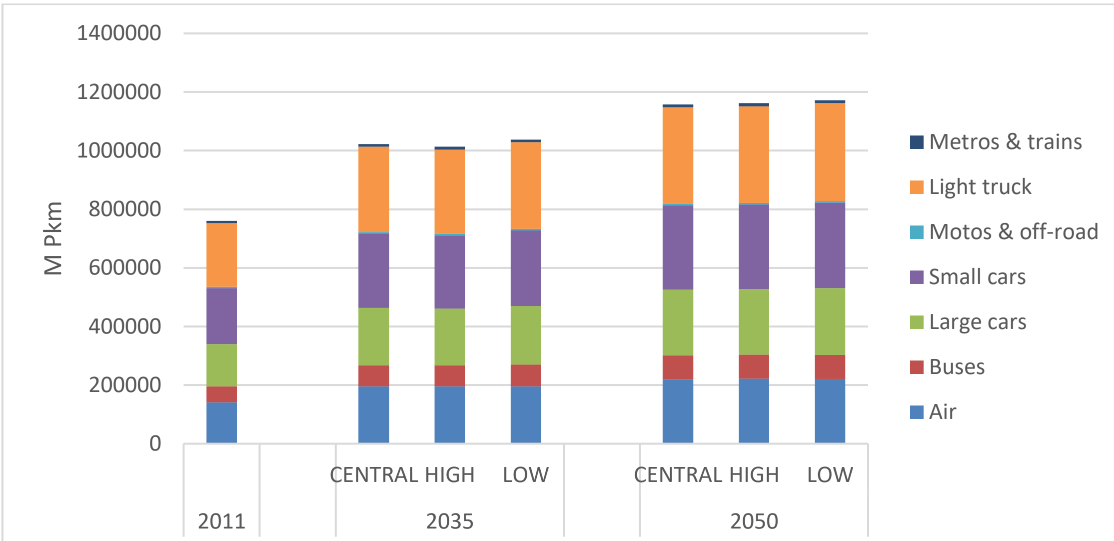
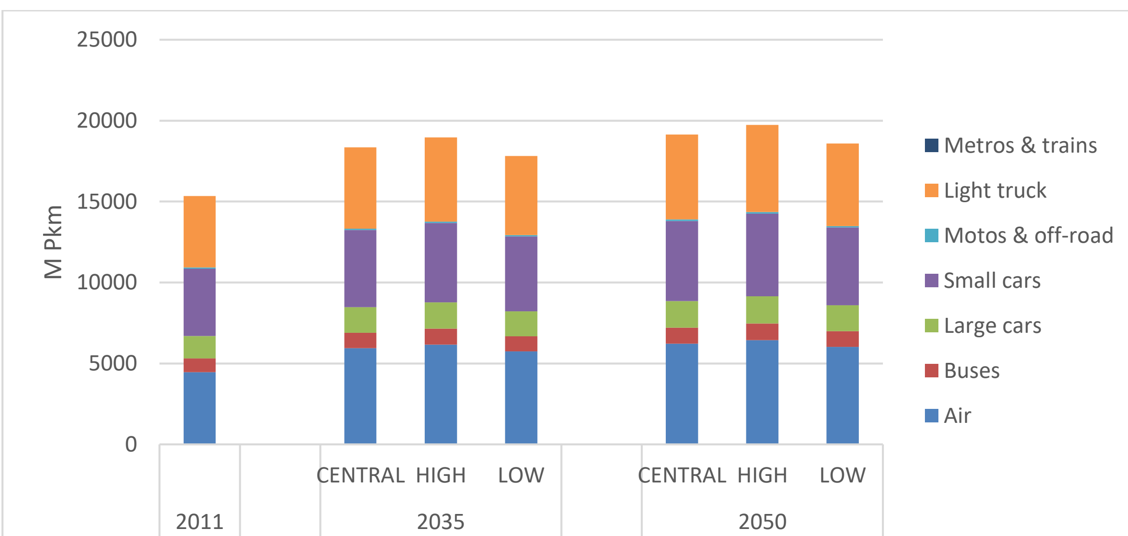


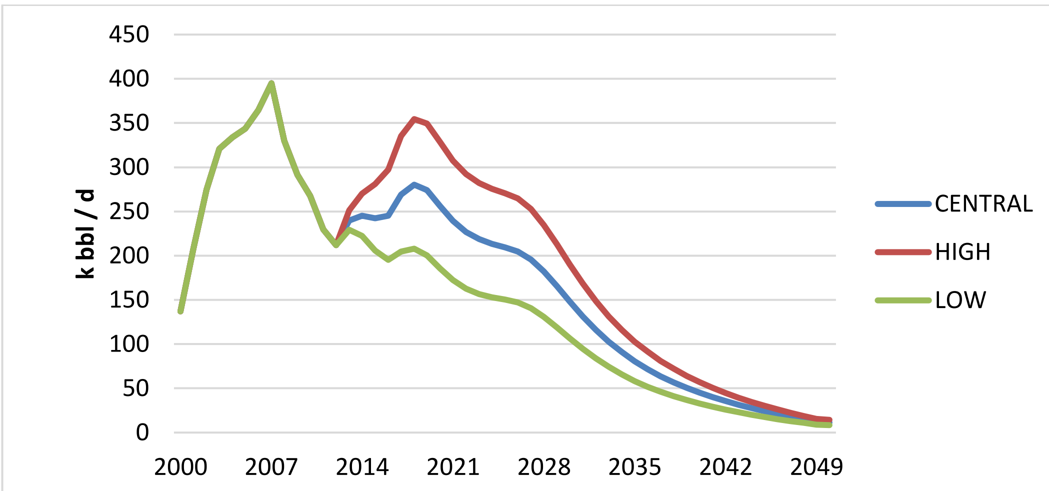
Figure 34. End-use demand projections for passenger transportation in Newfoundland and Labrador



4.3.1.2 Oil production from the forecasting model

Using the same sets of oil prices (NEB, 2013), the oil production profiles as given by the forecasting model are illustrated in Figure 35. These production profiles are used as the starting point in the TIMES model, which is calibrated to generate the same oil production levels in the corresponding three baseline scenarios. The comparison of each baseline scenarios are compared with the NEB forecast in Figure 58, Figure 59 and Figure 60 in Annexes.

Figure 35. Offshore oil production in Newfoundland and Labrador



4.3.2 Scenarios on pipeline capacities

4.3.2.1 Pipeline capacities for international exports from the WCSB

In all scenarios, the international export capacity as defined in the model illustrates the situation where all new pipeline projects would take place (as in Table 8). A set of assumptions was described in Vaillancourt et al. (2015) to define the real availability of pipelines for international exportation from the WCSB. These assumptions take into account the portion of each pipeline not available due to their current use for domestic exports or due to the competition with the oil entering pipelines on the other side of the USA border (CAPP, 2014b). Given these assumptions, the remaining available capacity is 4,858 PJ and is expected to be doubled by 2020 with an additional 4,986 PJ of capacity (Table 13).

A breakdown by type of destinations gives a better illustration of the saturation levels and potential for increases. Most of the existing capacity (97%) is used to export oil to Southern markets, while only a marginal portion (15%) is sent to Western markets. The addition of new capacity will allow current exportation levels to the Southern markets to increase by 1.79 times and to the Western markets by 65 times.

Table 13. Available pipeline capacity for international oil exports by destination

	Existing capacity	New capacity	Total capacity	Exports in 2011	% of capacity in 2011
	PJ	PJ	PJ	PJ	%
Southern markets	4,679	3,448	8,127	4,546	97%
Western markets	179	1,538	1,717	27	15%
Total international	4,858	4,987	9,844	4,573	

The objective of a previous study (Vaillancourt et al., 2015) was to analyze scenarios with different assumptions about the pipeline capacity available to supply the WCSB oil on various markets: for example with and without the most important projects such as TransCanada Keystone XL (1,876 PJ of additional capacity for international trade) and/or the Enbridge Northern Gateway (1,187 PJ of additional capacity for international trade). These scenarios were tested in order to view the impacts on the Canadian oil production levels and trade movements both within and outside Canada. The impacts was shown on the oil sector specifically and on the overall energy system in general. However, this work build on that baseline assuming that all projects would be available to export WCSB oil to international markets.

4.3.2.2 Pipeline capacities for domestic exports

The objective of the current study is to analyze four scenarios with different assumptions about the pipeline capacity available to supply the WCSB oil to Eastern provinces, Newfoundland and Labrador in particular:

S1: This scenario represents the reference situation where all new pipeline projects would take place allowing WCSB oil to reach refineries in Central and Eastern Canada: Enbridge Line 9 reverse (PJ up to Ontario and Quebec) and TransCanada Energy East (2,486 PJ up to Quebec and New Brunswick and then up to Newfoundland and Labrador via marine tankers or barges). The NATEM model will optimize Western oil imports for Eastern refineries as all as for further international exports from Eastern provinces.

S2: This scenario represents a situation where the TransCanada Energy East pipeline would reach the province of Quebec, New Brunswick and Nova Scotia for uses in refineries and further direct exports to international markets. Consequently, Newfoundland and Labrador would not have access to the oil coming from the WCSB.

S3: This scenario represents a situation where the TransCanada Energy East pipeline would reach Quebec, New Brunswick and Nova Scotia refineries, but would not include further direct export options to international markets. Consequently, Newfoundland and Labrador would have more access to the oil coming from the WCSB.

S4: This scenario represents a situation where the TransCanada Energy East pipeline project would be cancelled, which would preclude WCSB oil from reaching either refineries in Central and Eastern Canada or international markets from Eastern provinces.

In summary, there are three baseline scenarios (CENTRAL, HIGH, LOW) and four pipeline capacity scenarios for exporting oil West to East (S1, S2, S3, S4). Scenario S1 is a complete flexible scenario where the model optimizes the investment options in TransCanada Energy East pipeline as well as the energy flows between Western Canada and Eastern Canada. Scenario S2 aims at showing the impacts of not having this pipeline option for Newfoundland and Labrador. Scenarios 3 and 4 are more extreme cases, created mainly to test the methodology. See Table 14 for maximal pipeline capacities in Eastern Canada.

Table 14. Available maximal pipeline capacity for domestic oil exports

	QC, NB, NS	**NL**
S1	Full capacity: 2,486 PJ	Full capacity minus the portion exported to USA and ROW: 2,486 PJ - X PJ
S2	Full capacity: 2,486 PJ	No link up to NL: 0 PJ
S3	Full capacity: 2,486 PJ	Full capacity that remain available up to NL: 2,486 PJ
S4	No pipeline: 0 PJ	No pipeline: 0 PJ

4.4 Results

4.4.1 Baseline scenarios

From the end-use demands for energy services up to 2050 and using the reference scenario S1 for pipeline capacity, the NATEM model computes the optimal solution satisfying the final energy demand in each of the three baseline scenarios: CENTRAL, HIGH and LOW. Below, details are provided on the corresponding energy consumption and production pathways required to meet the projected end-use demands. Results are reported on a national and provincial basis, i.e. for Newfoundland and Labrador essentially and compared with Canadian averages when relevant.

4.4.1.1 Final energy consumption

Figure 36 shows the breakdown of final energy consumption by end-use sector in the three baseline scenarios in Canada. The total Canadian final energy demand is expected to increase by 23% in the CENTRAL scenario on the 2050 horizon, with 50% of the additional demand coming from the central region (Quebec and Ontario) and another 35% coming from Western provinces (mainly British Colombia and Alberta). One third of the final energy is consumed by transportation (32%), which also account for 20% of the additional demand in 2050. Important growth is also coming from the commercial and industrial sectors, which accounts for 30% and 32% of the additional demand and represent 49% of the final demand in 2050.

Regarding the breakdown of final energy consumption by fuel type (Figure 37), fossil fuels and oil products in particular will continue to dominate the markets on the long term. In 2050, the fuel mix is characterized by 39% of oil products and 25% of natural gas in the CENTRAL scenario. However, the highest growth is observed for electricity due to the higher growth in the end-use sectors relying on these fuels (e.g., commercial) and the large variety of options available for electricity generation in Canada. Electricity accounts for 52% of the additional energy demand up to 2050. The shares of biomass in the total energy consumption remains small (8% in 2050).

Figure 36. Final energy consumption by end-use sector in Canada

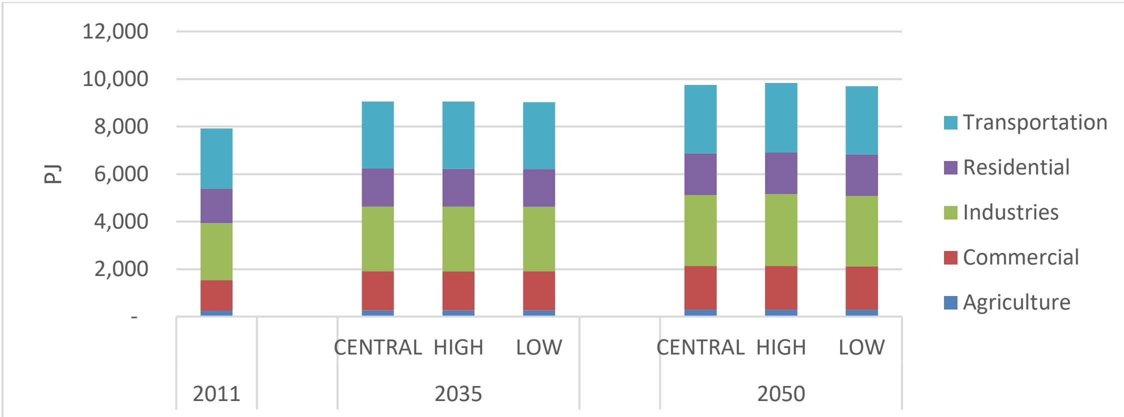
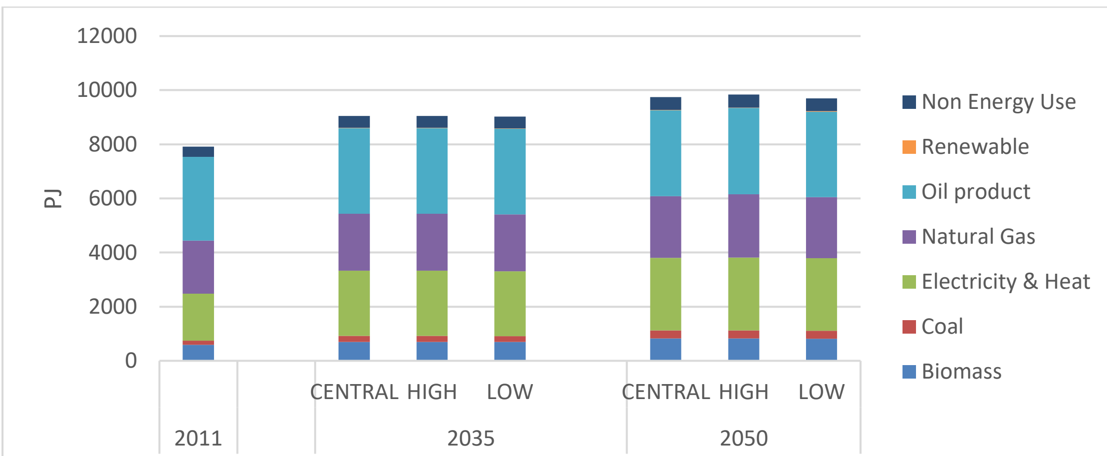


Figure 37. Final energy consumption by fuel type in Canada



For Newfoundland and Labrador specifically, Figure 38 shows the breakdown of final energy demand by end-use sector in the three baseline scenarios. The total final energy demand is expected to increase by 12% through 2050 in the CENTRAL scenario, a growth that is lower than the Canadian average (23%). Regarding the relative proportion of each sector in the total final energy demand, there are structural difference when comparing Newfoundland and Labrador to the national average. Specifically, the transportation sector represents a higher share for Newfoundland and Labrador (46% in 2011 compared with 32% for Canada), while industries represent a much lower proportion in Newfoundland and Labrador then in Canada as a whole (17% in 2011 compared with 30% for Canada). However, higher growth in the industrial sector minimizes these differences toward 2050, where industries account for 28% of the final energy demand in Newfoundland and Labrador.

The breakdown of final energy consumption by fuel type in the three baseline scenarios as illustrated in Figure 39 indicates that fossil fuels will continue to dominate the markets on the 2050 horizon as in Canada generally. However, there is a decreasing trend for oil products (from 63% in 2011 to 48% in 2050) in favour of electricity (from 28% to 37% on the same period). As for the national average, the use of biomass remains flat through 2050 (below 8%).

Figure 38. Final energy demand by end-use sector in Newfoundland and Labrador

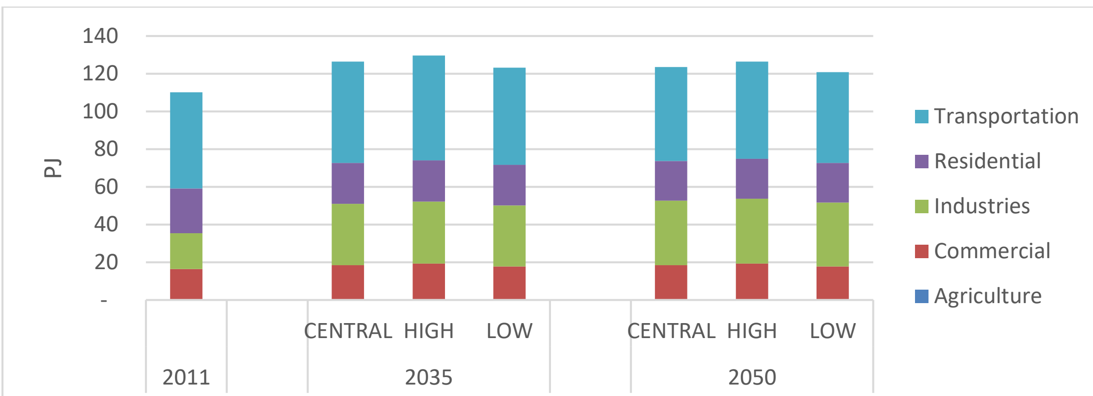
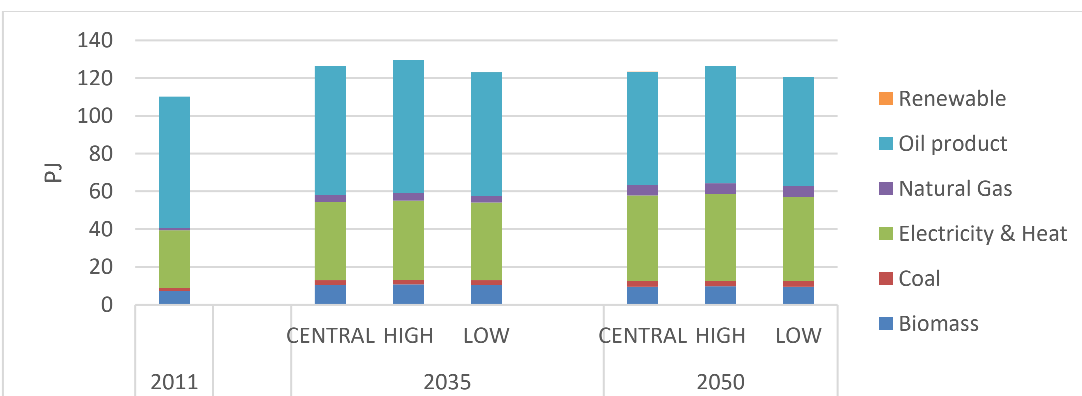


Figure 39. Final energy demand by fuel type in Newfoundland and Labrador



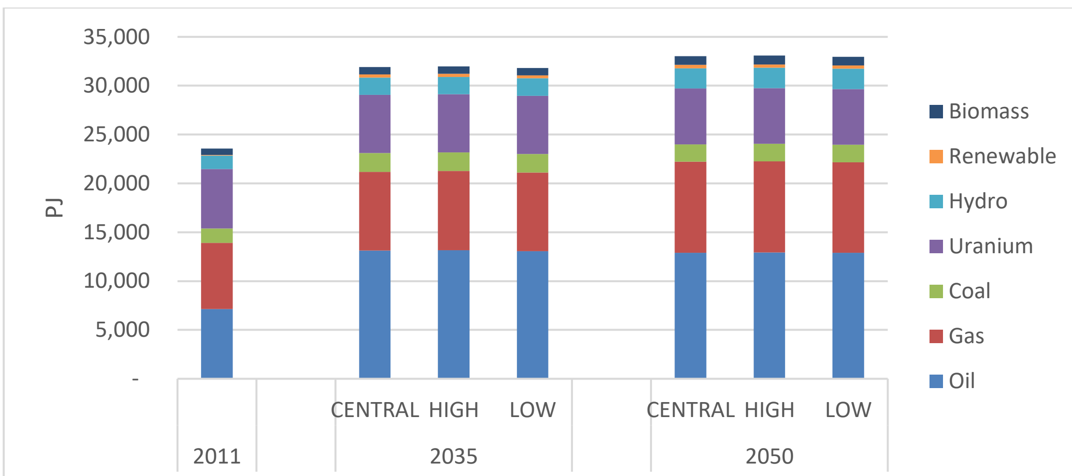
The variation of results across the different baselines is consistent with the NEB (2013) assumptions regarding the evolution of socio-economic trends. In some provinces, the final energy demand is increasing faster in the LOW scenario compared with the CENTRAL case and vice versa for the HIGH scenario due to the fact that higher oil prices put higher pressure on the final energy demand growth. However, in oil producing provinces, this trend is offset by the fact that the oil and gas sector is increasing with oil prices, which create more GDP and leads to higher growth in final energy demand. For instance, in Newfoundland and Labrador, the HIGH scenario leads to only a more significant growth in the final energy demand (14.8%) compared to the CENTRAL scenario (12.0%), while the LOW scenario leads to a lower growth (9.5%) by 2050. This range in the final energy consumption will be useful to analyse the impact of the pipeline capacity scenarios on oil prices in Newfoundland and Labrador.

4.4.1.2 Primary energy supply

This section presents more details regarding the optimal energy production paths required to meet the final energy demand, both for domestic consumption and for international exports. Figure 40 shows the energy production by type in the three baseline scenarios. In the CENTRAL scenario, most of the growth in oil production (84%) is occurring between 2011 and 2035, before slowing down between 2035 and 2050 (-2%). Gas production grows by 38% in the 2050 horizon due to its significant reserves, with a larger penetration of unconventional gas compensating for the decline in conventional gas production. Conventional gas sources are mainly concentrated in the Western region (76% in Alberta). The production starts decreasing with the extra supplies of unconventional gas on the markets and continues to decline on the long term due to the lower well production rates (NEB, 2013). With technological progress for unconventional gas extraction (i.e., horizontal drilling and hydraulic fracturing) as well as conventional gas reserve depletion, the production from unconventional gas wells is becoming more profitable and allows the overall gas production to increase again from 2020 after a decline in the total gas extraction activities. Most of the unconventional gas production (mainly tight and shale gas, but also coalbed methane) is located in British Colombia and Alberta. Frontier gas reserves from the Northern and the offshore Eastern regions are not included in the model.

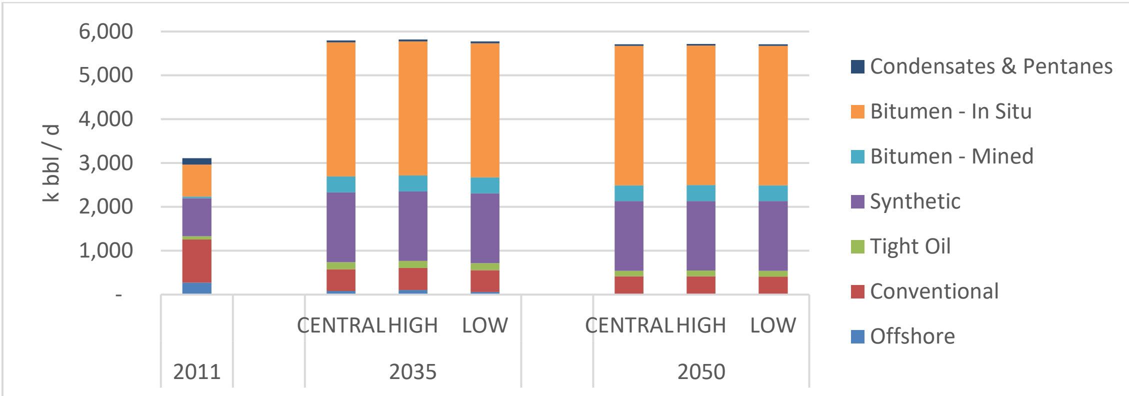
Due to coal power phase out in many provinces, coal production grows by only 20% for domestic uses in industries and international exports. Uranium extraction follows a decreasing trend (-6% between 2011 and 2050) following nuclear plant closures. Hydro follows a constant increase representing a 50% growth between 2011 and 2050. Finally, although other renewable production increase by a factor 7, its proportion in the overall production mix remains around 1%. Overall, the primary energy production remains between 39.8% and 40.3% for the three baseline scenarios.

Figure 40. Primary energy production by type in Canada



In particular, Figure 41 compares the breakdown of crude oil production by type in the three baseline scenarios. The large majority of the oil production is exported on international markets and the international demand for Canadian crude is the main driver for oil production levels. In this work, we have assumed that the international demand for Canadian crude is constant across scenarios both for simplification reasons and for the minor expected effect on domestic consumption. More precisely, the international demand for Canadian crude is limited in a way that the oil production levels do not excess those forecasted by the NEB (2013) as shown in Figure 42. After the limit on the pipeline capacity to exports crude from the WCSB is reached (Section 4.3.2.1), additional exports can occurred from the Eastern provinces, since the TransCanada East pipeline capacity exceeds the capacity needed to supply refineries in Quebec and Atlantic provinces. The maximum production levels as taken from the NEB (2013) are reached in all scenarios.

Figure 41. Oil production by type in Canada



In relation to the stability of the domestic demand for oil across the different baseline scenarios, it is not surprizing to see in Figure 41 that domestic economic trends have very little impact on oil production levels. Oil production increases by 1.8 time from 2011 level and is expected to reach 5,710k bbl/d in 2050. The production shows constant increase with the highest growth rates being between 2013 and 2025, when most of the new pipeline capacities are becoming available.

Most of the oil production is coming from the WCSB, with conventional oil representing only 10% of the total production in Canada in 2050. The WCSB is a mature basin, where conventional oil production declines at significant faster rates between 2025 and 2050. The 19% increase between 2011 and 2020 is due to the availability of enhanced oil recovery options, extending the life of some wells and the extraction of tight oil. The two sources of new project developments come from Western oil sands and Newfoundland offshore production. While oil sands (mined and in situ extraction, plus synthetic production from both types) represented already half of the total oil production in 2011, it is expected to represent 90% of the production in 2050. The proportion of oil sands extracted via in situ techniques is expected to represent 58% of the overall production in 2050, as the mined activities for oil sands extraction should increase only slightly (from 28% to 32% in 2050). A significant portion of this oil sands production via mined or in situ techniques is converted to synthetic oil. Synthetic oil production from oil sands upgrading is expected to provide 28% of the total production in 2050.

Figure 42. Oil production by type in Canada compared with the NEB (2013) forecasts

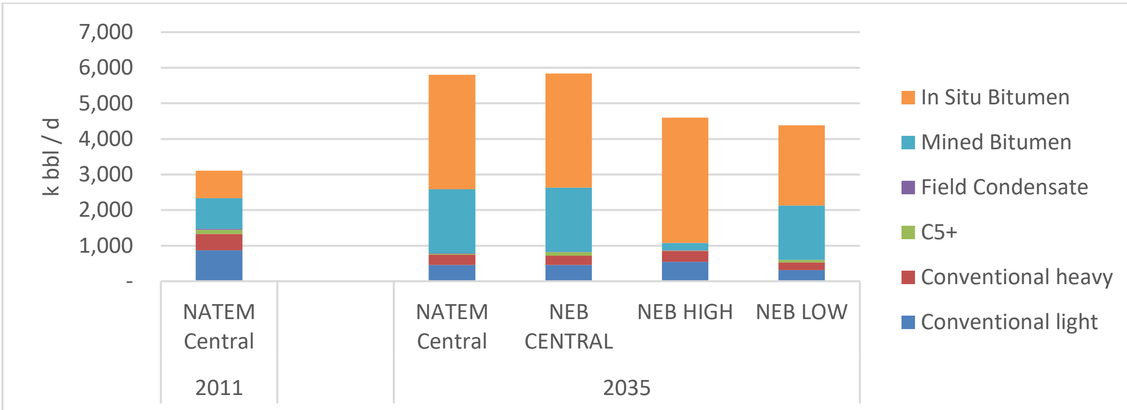
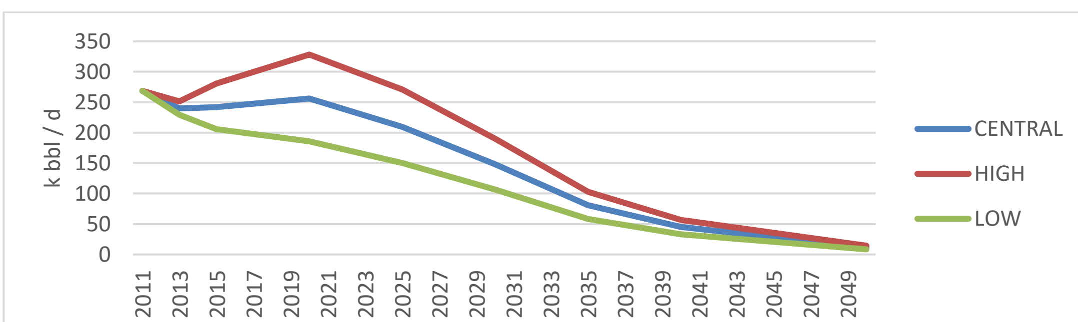


Figure 43 show the evolution of the total offshore oil production in Newfoundland and Labrador through 2050 to meet both the domestic demands and international exports in the three baseline scenarios. The outcomes of the forecasting model for the three different oil price scenarios (Figure 32) are used as fixed production levels in NATEM. Note, however, that NATEM uses longer time period than the forecasting model which is annual. Oil production peaks around 2020 (328 kbbl/d in the HIGH scenario) before starting to decline.

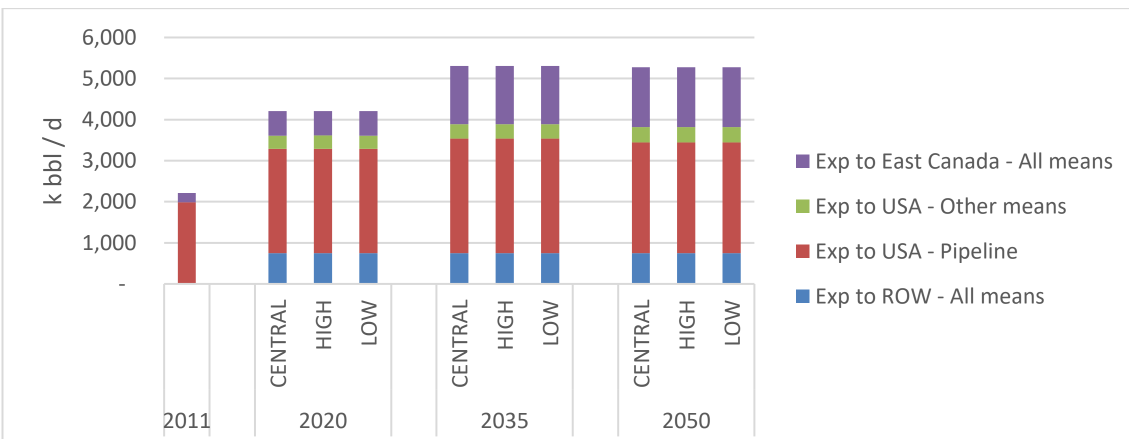
Figure 43. Oil production in Newfoundland and Labrador– original from the forecasting model



4.4.1.3 International and domestic exports from WCSB

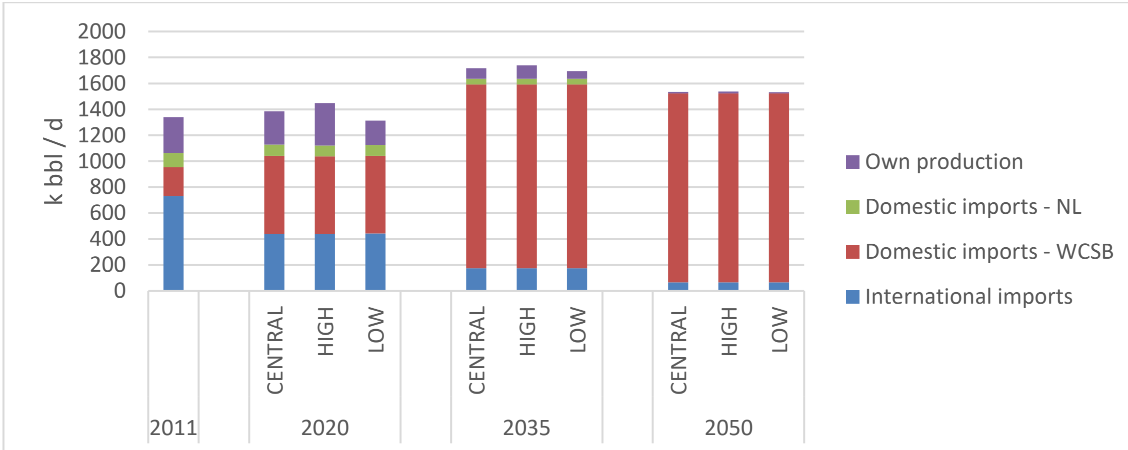
Before analyzing the supply-demand dynamics in Eastern Canada for the different pipeline capacity scenarios, it is relevant to have a look at the supply-demand dynamics in Canada as a whole. Figure 44 shows the oil exports by destination from Western Canada, while Figure 45 shows the oil imports by origin in Eastern Canada. Oil exports are almost exclusively oriented to USA markets by pipeline in 2011 (98%), but they start to be diversified both in terms of transportation means and other destinations in the rest of the world due to higher oil prices (Table 11). In addition, Western provinces start to move synthetic oil to Eastern provinces via the TransCanada East pipeline from 2020 and the pipeline is used at full capacity from 2030. It is important to note that an important portion of that oil is further exported to international markets and that not all is used in Eastern refineries. Trading movements from the WCSB to Ontario through the existing Enbridge pipeline are also included in the domestic export numbers.

Figure 44. Oil exports by destination from Western Canada



As for the origin of the oil supply in Eastern Canada, it is apparent that imports through the TransCanada East pipeline represent the majority of the mix when this option becomes available. Since the oil production in Newfoundland and Labrador is decreasing to almost zero in 2050 (assuming no new field will be discovered and developed), all refineries in Eastern Canada will need to rely on domestic imports from the WCSB and on international imports in a lesser manner. The next section presents more details on the origin of imports and the use of crude oil by province.

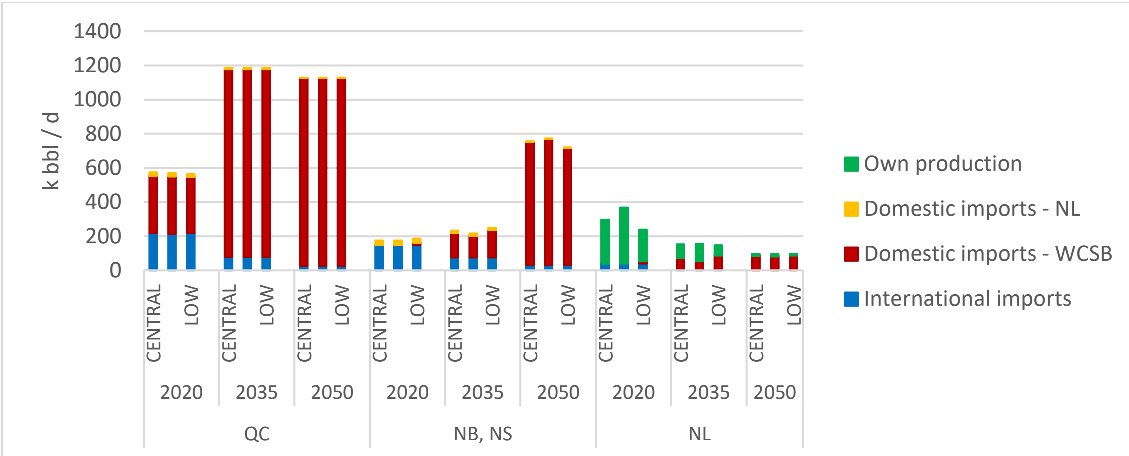
Figure 45. Oil imports by origin in Eastern Canada



4.4.2 Pipeline capacity scenarios

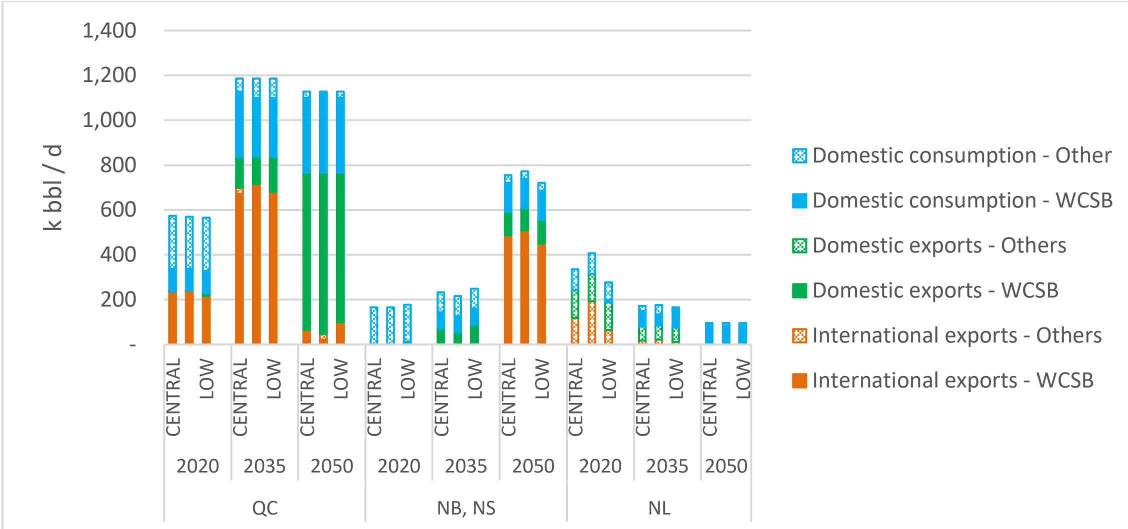
This section looks at the supply-demand dynamics in Eastern provinces in particular for the different pipeline capacity scenarios. Figure 46 shows the same type of information as in Figure 45 for the three baseline scenarios, albeit at a provincial level, in order to better understand the trade movements in Eastern Canada. As mentioned earlier, oil imports from the WCSB start as soon as the TransCanada pipeline becomes available in 2020 and reach its maximum capacity (1100 k bbl/d) around 2030. Quebec, New Brunswick and Nova Scotia have access to synthetic oil from the WCSB for use in domestic refineries or exports to USA and/or Rest of the World. In Newfoundland and Labrador, the synthetic oil from the WCSB is used solely in the refinery since there are no option assumed in the model for further exports of synthetic oil to international markets. Synthetic oil is assumed to replace the offshore oil as its production decreases over time.

Figure 46. Oil imports by origin and by province in Eastern Canada



More details are given in Figure 47 regarding the different uses of the WCSB synthetic oil as well as other types of crude oil that reach or is being produced in Eastern provinces. Synthetic oil is replacing a significant portion of the imported crude oil used in Quebec's refineries: between 75-82% in 2035 and 92% in 2050. The remaining portion represents the imported light oil from Africa, the North Sea and the Middle East. It is important to note, however, that this crude mix is strongly dependent on the assumptions about the imported light oil prices and quantities. Since the needs of the province are small compared with the size of the TransCanada East pipeline, the vast majority of the synthetic oil coming through is exported to the USA toward 2035. An interesting change occurring between 2035 and 2050 is related to the destination of the WCSB oil: direct exports from Quebec to USA toward 2035 are decreasing to the profit of domestic exports to New Brunswick and Nova Scotia for international exports to Rest of the World – East where the oil prices are expected to be higher (Table 6). In Newfoundland and Labrador, the WCSB oil is replacing the majority of the offshore oil in the refinery (between 90% and 98% by 2050). The offshore production is mainly exported on international markets.

Figure 47. Oil demand by province in Eastern Canada



The remaining part of the section looks at the effects of the different pipeline capacity scenarios on the supply and demand dynamics of each province. The oil imports by origin and by province in Eastern Canada as shown in Figure 46 and the oil demand by province in Eastern Canada as shown in Figure 47 represent the reference situation in terms of pipeline capacity (S1); the same complete results are shown in Annexes for oil imports in S2 (Figure 60), S3 (Figure 61) and S4 (Figure 62) as well as for oil demand in S2 (Figure 63), S3 (Figure 64) and S4 (Figure 65).

Since the different assumptions underlying the three baseline scenarios do not affect the results in a significant manner, the comparison analysis focuses on the central scenario for each pipeline capacity scenarios. The variations in oil import patterns according to the different pipeline capacity scenarios are illustrated subsequently for Quebec (Figure 48), New Brunswick/Nova Scotia (Figure 49) and for Newfoundland and Labrador (Figure 50). The S2 does not have a significant effect on the oil supply mixes in Quebec and New Brunswick/Nova Scotia for their own use. However, since it assumes that the WCSB oil will not reach Newfoundland and Labrador, less synthetic oil is imported through New Brunswick in 2035 to reach Newfoundland and Labrador.

Figure 48. Oil imports by origin in Quebec in the pipeline scenarios

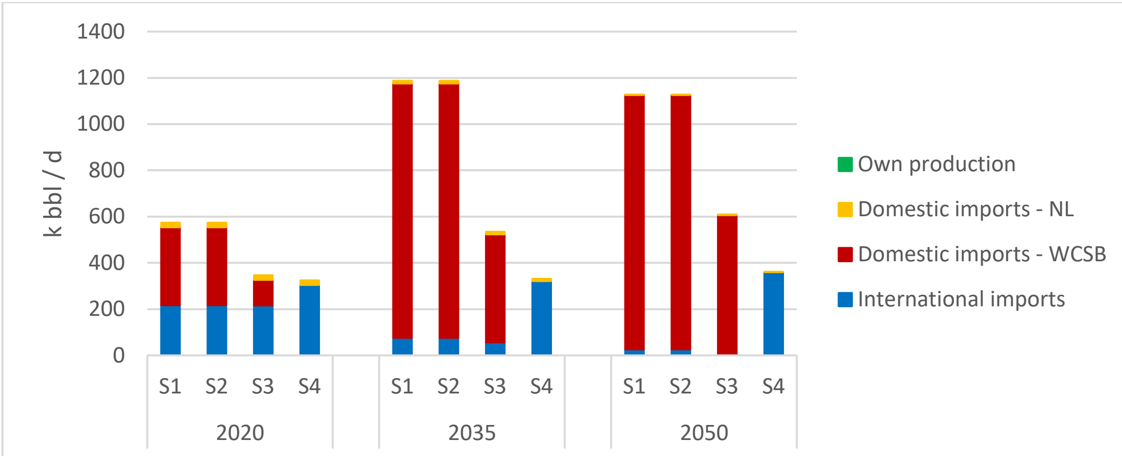


Figure 49. Oil imports by origin in New Brunswick/Nova Scotia in the pipeline scenarios

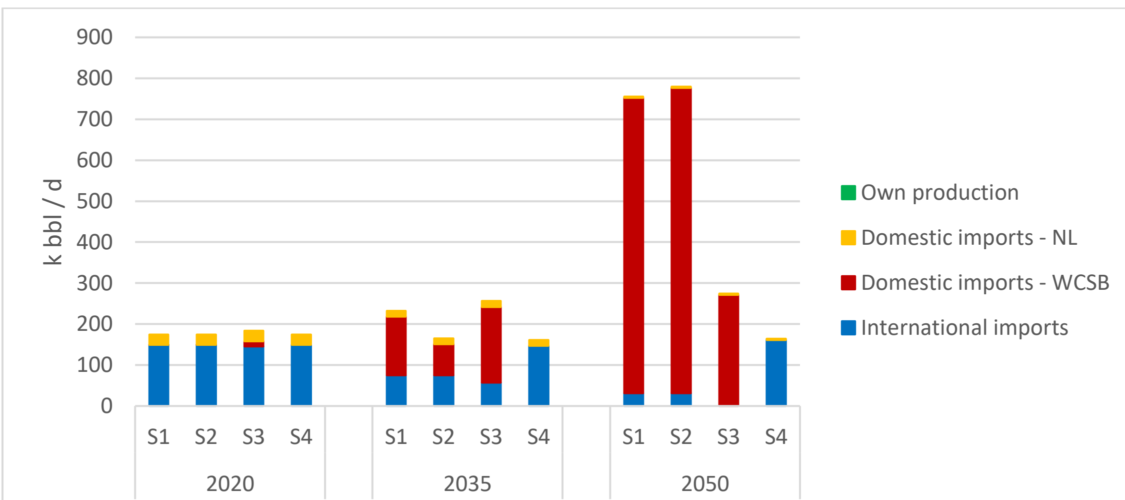
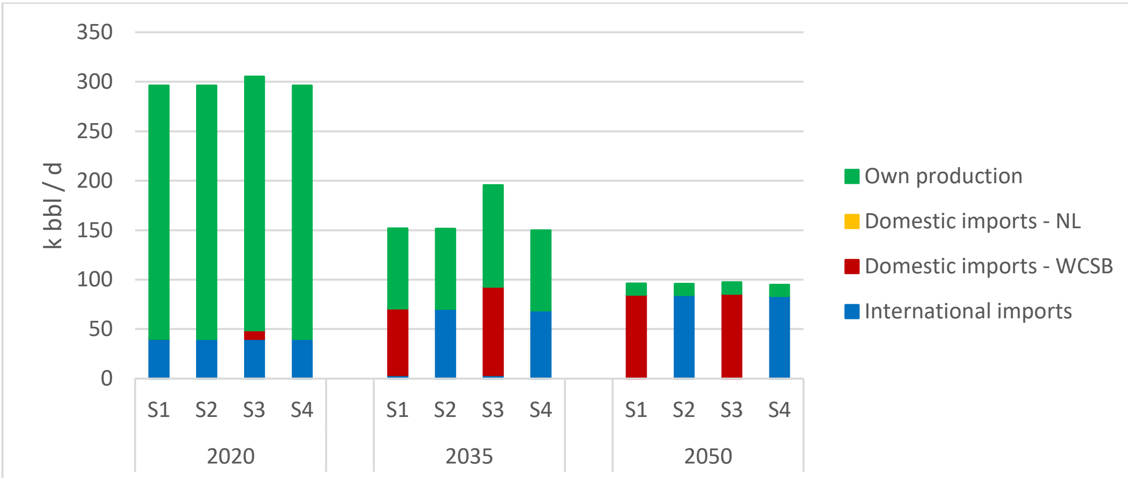


Figure 50. Oil imports by origin in Newfoundland and Labrador in the pipeline scenarios



As for S3, which assumes that there will be no international exports from Quebec and New Brunswick/Nova Scotia, it affects the oil supply mixes in a more significant manner in all provinces. As a larger proportion of the WCSB oil imported in Eastern Canada is for international exports, the trading flows between Western and Eastern Canada in general are much reduced. However, Quebec can reduce its imports from international markets and this leaves larger amount of the WCSB oil available for exports to Newfoundland and Labrador. Finally, there are no access at all to WCSB oil for Quebec and Atlantic provinces in S4. This situation requires some provinces to import more oil from other markets (international as well as from Newfoundland and Labrador) although the changes are minor. The biggest impacts are on the demand side.

The variations in oil demand patterns according to the different pipeline capacity scenarios are illustrated subsequently for Quebec (Figure 51), New Brunswick/Nova Scotia (Figure 52) and for Newfoundland and Labrador (Figure 53). In S2, when Newfoundland and Labrador does not have access to synthetic oil, more of this oil is available for domestic use in Quebec and New Brunswick. The impact results in Newfoundland and Labrador being a greater user of its own domestic production for refining to the detriment of international exports. The limitation of international exports in Quebec and New Brunswick in S3, promotes a larger use of synthetic oil in domestic refineries in all provinces. Newfoundland and Labrador can increase its refining activities, its exports of refined products as well as international exports of its offshore oil. However, this has much less effect on the trade movement between Western and Eastern Canada than the international demand for WCSB oil.

Figure 51. Oil demand in Quebec in the pipeline scenarios

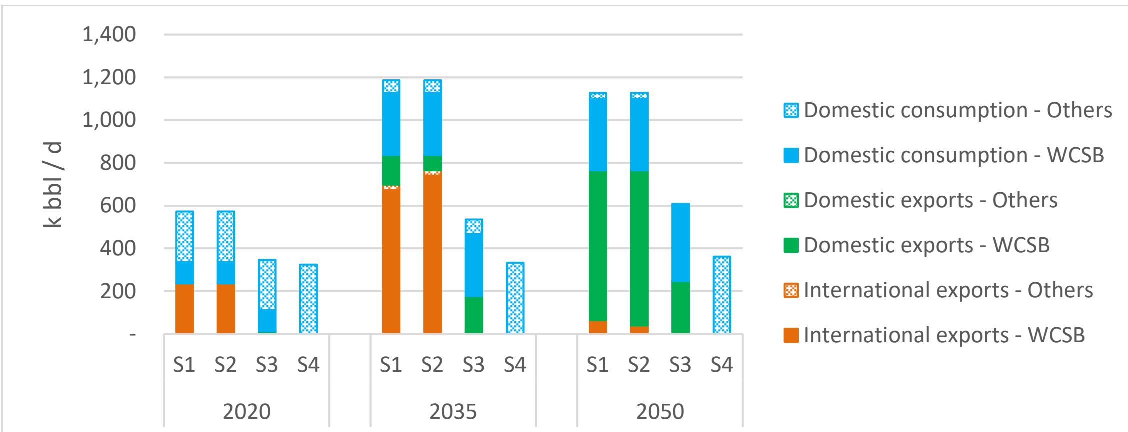
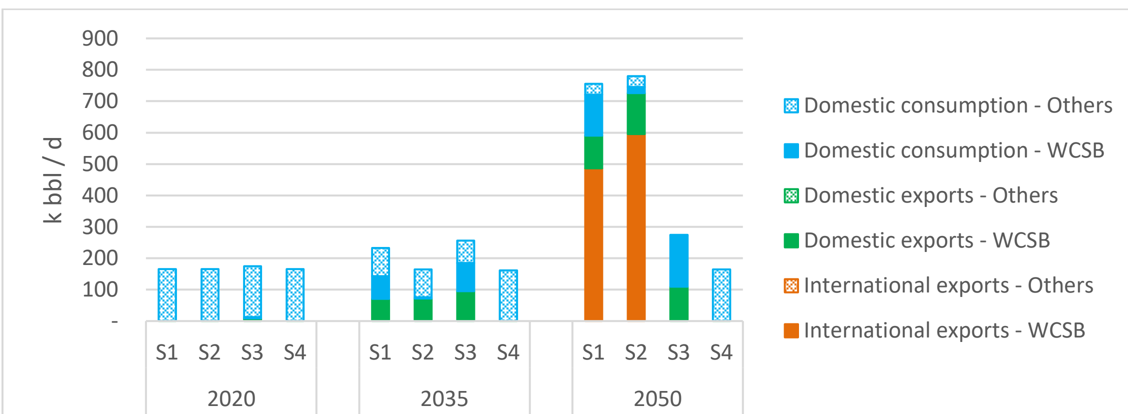
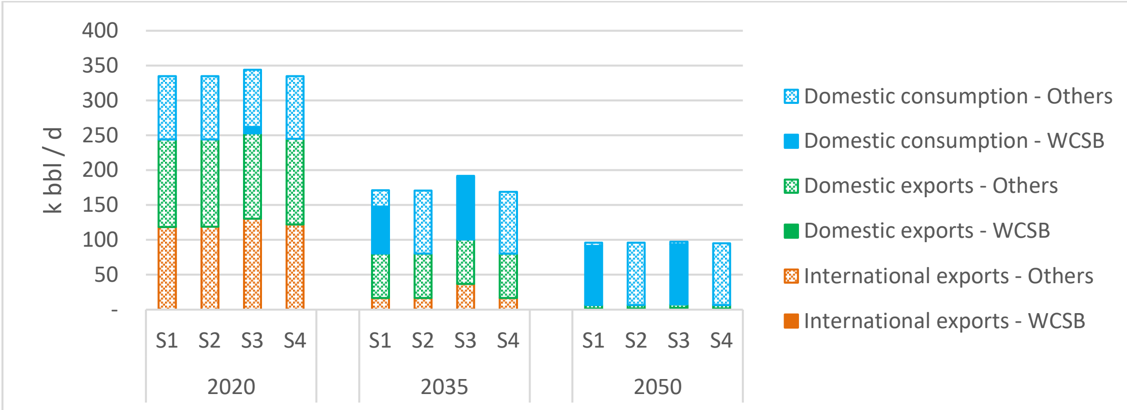


Figure 52. Oil demand in New Brunswick/Nova Scotia in the pipeline scenarios



The effects of having less access to WCSB oil in Eastern Canada in S4 is clearly a decrease in activities both domestically and internationally. Interestingly, the impacts on the total production levels in the WCSB is light as more synthetic is exported directly to the USA.

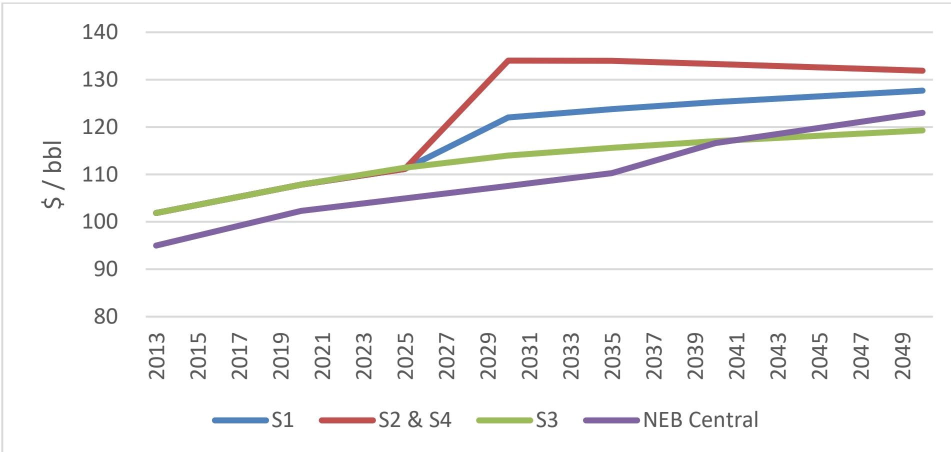
Figure 53. Oil demand in Newfoundland and Labrador in the pipeline scenarios



4.4.3 Impact on oil prices and production levels

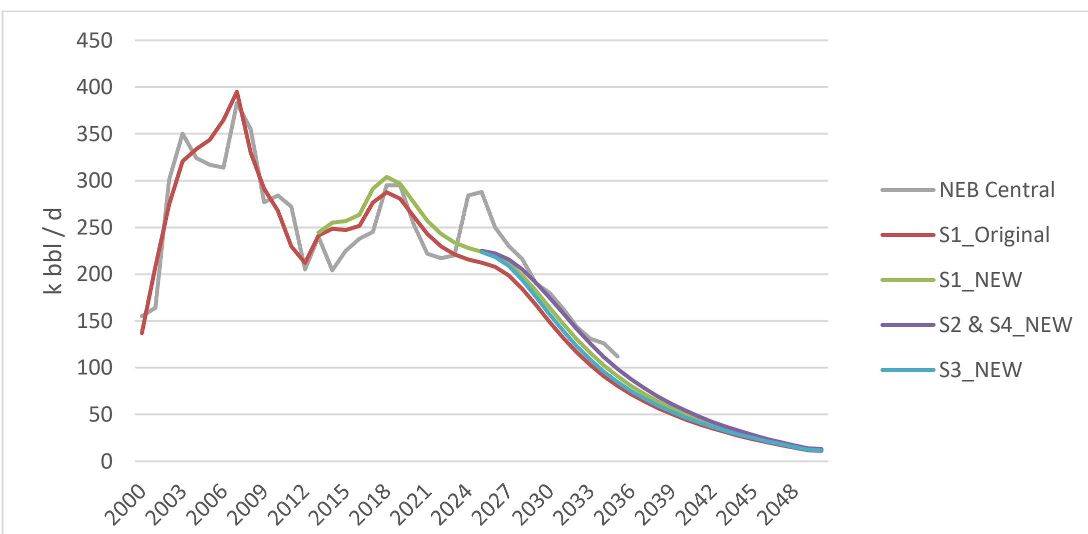
This section shows the effects of the pipeline capacity and the access to WCSB oil on the offshore oil commodity prices and production in Newfoundland and Labrador (Figure 54), using the first iteration between the forecasting model and NATEM. When the model can optimize the quantities of synthetic oil coming from the WCSB up to the maximum TransCanada East pipeline capacity, such as in S1, there is more competition between different crude types. This allows prices to converge at 128$/bbl by 2050 in all three baselines. Blocking the access to WCSB oil in Newfoundland and Labrador, such as in S2, brings the offshore oil price up by 10$/bbl in 2035 and 4$/bbl in 2050. As for the other two scenarios, there are more extreme and perhaps less realistic, but they illustrates well the utility of the proposed framework to analyse supply-demand dynamics in Eastern Canada. In S3, the prices are going down further with an excess of WCSB oil coming to Newfoundland and Labrador, while they remain high in S4, when the whole pipeline project is cancelled (this scenario has impacts on the oil prices in other Eastern provinces). The comparison of these prices with those of the NEB (2013) in their central scenario shows that their assumptions on the availability of crude oil on all Canadian markets are optimistic.

Figure 54. Marginal oil commodity prices in Newfoundland and Labrador in the pipeline scenarios



Finally, the forecasting model is also used to show the impacts of new oil prices in our optimal scenario (S1) compared with a situation where Newfoundland and Labrador would have more or less access to synthetic oil from WCSB (S2, S3 and S4) on oil production levels (Figure 55).

Figure 55. Oil production in Newfoundland and Labrador after an iteration with the forecasting model



The oil production is higher in the new production profile (S1_NEW) than in the original profile (S1_Original) due to higher marginal prices in the NATEM scenarios than in the central case of the NEB (Figure 54). The oil production difference peaks in 2036, showing a 13% higher level than in the NEB. Considering the average increase between 2013 and 2050, S1 is about 9% higher levels than the central case of the NEB overall. If we consider the reserves available in 2013, S1 shows 8% more reserves than in the NEB case due to the incentive of higher oil prices. Indeed, this new pattern in higher oil prices creates an incentive to drill more wells when the field oil production profile is higher compared to the original case. The impact is more significant up to 2030, since the contribution of each well is higher when the field is younger. Afterwards, the contribution is much less significant as the field is maturing and the contribution of each new well becomes smaller.

At first sight, it seems there is not much differences in the oil production profiles between the different pipeline capacity scenarios as the impacts of having more or less access to the TransCanada East pipeline is only possible beyond 2020. However, after looking more closely to the different production profiles, it becomes apparent that the differences are meaningful and require some considerations. The S2 scenario leads to the biggest benefits in terms of offshore production since there is no competition with Western oil. For this case, the oil production difference peaks in 2034, showing up to a 23% increase in production compared with the central case of the NEB. The average increase between 2013 and 2050 is about 14%. Regarding the available reserves in 2013, S2 shows 10% more reserves than the NEB. For S3, the highest difference occurs in 2032, at 6% higher than the NEB. The average increase between 2013 and 2050 is 5% and the available reserves are 6% higher.

In summary, the access to Western oil would allow the Eastern provinces to maintain crude oil prices at lower level than if they would need to import crude oil for international markets.

4.8 Conclusion

This report focuses specifically on the impact of the TransCanada pipeline on the oil and gas industry in Newfoundland and Labrador. A soft-linking model framework was presented and applied to a specific case study to generate insights on: 1) the domestic oil supply-demand dynamic in Canada under different economic growth scenarios; and 2) the impacts of different pipeline projects on the oil supply-demand dynamic in Eastern provinces, Newfoundland and Labrador especially. The NATEM model database was presented into more details for the oil sector. The results discussed in the report illustrate well the potential of the model framework to analyse such supply-demand dynamics and to provide insights on market trends. This should be seen as a first step toward a broader and deeper analysis. Indeed, these are complex issues that would require more works in order to bring robust conclusions.

Future works will allow to improve this analysis from several point of view: extend the methodology to cover more aspects of the problem, refine data and assumptions to bring the definition of the problem closer to the reality and consider multiple scenarios to analyse the problem in all its dimensions.

From a methodological perspective, the next step would be to complete the loop by looking at the impact of oil prices changes on socio-economic growth forecasts in Newfoundland and Labrador using the NALEM model. This requires the collaboration of the Department of Finance – Government of Newfoundland and Labrador. We also think that the study would benefit from using a fiscal model to analyze the impact of marginal prices due to changes in pipeline capacities (or other changes in the oil sector) on GDP, taxes and profits per barrel (price-cost). In addition, the following improvements are considered to improve the representation of the oil sector in the NATEM optimization model:

- Give more flexibility to the model in order to optimize investments between 1) upgrading activities in the WCSB for synthetic oil exports in Eastern Canada, and 2) exports of diluted bitumen directly from the WCSB with additional upgrading activities in Eastern refineries (and, further diluted bitumen to USA and ROW).

- Increase the level of details in terms of transportation options as well as for international markets for different crude oil types and refined products.

- Refine the representation of refineries taking into account crude quality, blending options and corresponding output mix options.

- Add other sources of crude oil that can compete with Canadian crude such as the shale oil from North Dakota (USA), the new Statoil oil discovery in Newfoundland that could yield up to 600 million barrels of additional reserves.

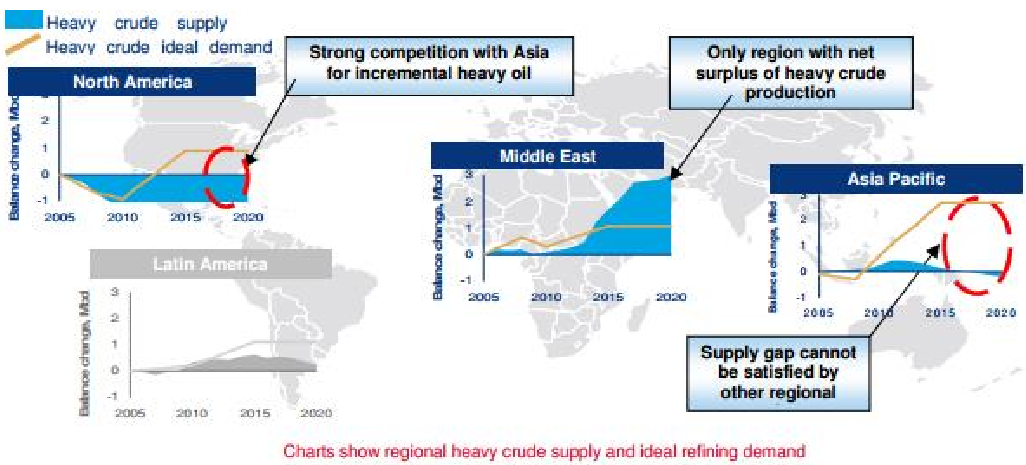
On the data, assumptions and scenario analysis aspects, it would be important to update the cost data as the information becomes available in the literature and to validate the most uncertain values with key players in the industry. Moreover, sensitivity analysis on the most critical factors is necessary to bring more robustness to the study such as transportation costs between different provinces. Finally, numerous additional scenarios would be relevant to address the most significant uncertainties impacting the evolution of the Canadian oil sector, namely:

- Scenarios with variations to demands for different types of crude oil in North American refineries: This is to study the future evolution of the refining sector with the possibility of both Valero and Irving building new refineries in North East America and Europe or facing possible refinery closures as the US refineries are becoming more competitive thanks to their access to cheaper oil supply.

- Scenarios with variations to the Brent over WTI differential: This differential is a relative new phenomenon due to the oversupply of North American crude oil and the limitations to access international markets. As more pipeline projects are concluded and political constraints are eliminated (e.g. the Jones Act) such limitations will decreased giving North American crude oil access to new markets willing to pay higher international prices.

- Scenarios with variations to the oil price assumptions by transportation route: the original assumption of a higher netback for the East (ROWE) route than for the West (ROWW) route needs to be challenged as other regions in the world evolve to produce and process heavy oil. As it can be seen on Figure 56, the Canadian bitumen is starting to have more competition from the heavy crude coming from Middle East. On the other side, Asian demand will also increase, giving more advantage to the West route as time approaches 2020.

Figure 56. Heavy crude oil supply change versus heavy crude oil ideal demand change



Source: Wood Makenzie (2011).

To conclude, we expect that this extended framework will shade lights with a greater level of robustness on uncertainties around:

- The availability of resources, capital cost of projects and planning process by companies as well as policy design by governments.

- Increasing oil price volatility.

- Connections and evolution of exploitation, transportation and refining under different oil prices and pipeline capacity scenarios.

- Geographical issues specific to the Canadian oil sector: imports and offshore production in Eastern Canada versus exports and oil sands production in Western Canada.

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Appendix

Table 15. Projection of end-use demands for energy services in Newfoundland and Labrador

Demand	Unit	2011	2013	2015	2020	2025	2030	2035	2040	2050
Beef	Mt	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Dairy	Mt	0.05	0.05	0.06	0.06	0.06	0.06	0.06	0.06	0.06
Eggs	Mt	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Fruit	Mt	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Grains and Oilseeds	Mt	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Hog	Mt	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other	PJ	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08
Poultry	Mt	-	-	-	-	-	-	-	-	-
Vegetables	Mt	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Auxiliary Equipment	PJ	3.11	3.31	3.48	3.55	3.63	3.64	3.65	3.70	3.80
Auxiliary Motors	PJ	1.24	1.32	1.39	1.42	1.45	1.45	1.46	1.48	1.52
Lighting	PJ	6.89	7.35	7.73	7.87	8.06	8.07	8.09	8.21	8.42
Other Services	PJ	4.26	4.76	5.09	5.78	6.19	6.54	6.86	7.03	7.19
Space Cooling	PJ	0.25	0.27	0.28	0.29	0.29	0.29	0.29	0.30	0.31
Space heating	PJ	4.00	4.27	4.49	4.57	4.68	4.69	4.70	4.77	4.89
Street lighting	PJ	0.25	0.27	0.28	0.28	0.29	0.29	0.29	0.30	0.30
Water heating	PJ	0.60	0.64	0.68	0.69	0.71	0.71	0.71	0.72	0.74
Ammonia	Mt	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Chlorine	Mt	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Other chemicals	Mt	-	-	-	-	-	-	-	-	-
Iron and steel	Mt	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Cement	Mt	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Other mining	PJ	2.59	2.66	2.72	2.73	2.85	2.85	2.86	2.92	3.02
Aluminium	Mt	-	-	-	-	-	-	-	-	-
Copper	Mt	-	-	-	-	-	-	-	-	-
Other non-ferrous metals	Mt	-	-	-	-	-	-	-	-	-
Other manufacturing industries	PJ	2.11	2.21	2.27	2.38	2.69	2.93	3.16	3.27	3.37
Other industries	PJ	6.01	6.29	6.46	6.78	7.65	8.35	8.99	9.32	9.61
High quality paper	Mt	0.56	0.57	0.58	0.59	0.61	0.61	0.61	0.62	0.65
Low quality paper	Mt	0.56	0.57	0.58	0.59	0.61	0.61	0.61	0.62	0.65
Space cooling - Attached Houses	PJ	-	-	-	-	-	-	-	-	-
Space cooling - Apartments	PJ	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Space cooling - Detached Houses	PJ	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cloth drying	PJ	0.66	0.71	0.73	0.79	0.83	0.88	0.93	0.96	0.98
Space cooling - Mobile Homes	PJ	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cooking	PJ	0.49	0.50	0.50	0.49	0.49	0.50	0.50	0.50	0.50

Demand	Unit	2011	2013	2015	2020	2025	2030	2035	2040	2050
Cloth washing	PJ	0.06	0.06	0.07	0.07	0.08	0.08	0.08	0.09	0.09
Dish washing	PJ	0.04	0.05	0.05	0.05	0.05	0.06	0.06	0.06	0.06
Freezing	PJ	0.24	0.26	0.27	0.29	0.30	0.32	0.34	0.35	0.36
Space heating - Attached Houses	PJ	0.97	0.98	0.99	1.00	1.00	1.00	1.00	1.00	1.00
Space heating - Apartments	PJ	0.81	0.82	0.83	0.84	0.84	0.84	0.84	0.84	0.83
Space heating - Detached Houses	PJ	11.66	11.82	11.96	12.03	12.07	12.06	12.04	12.03	12.00
Space heating - Mobile Homes	PJ	0.19	0.19	0.20	0.20	0.20	0.20	0.20	0.20	0.20
Lighting	PJ	1.68	1.75	1.80	1.82	1.88	1.88	1.89	1.91	1.96
Other electric equipements	PJ	1.29	1.38	1.44	1.55	1.62	1.73	1.83	1.88	1.93
Refrigeration	PJ	0.48	0.51	0.53	0.58	0.60	0.64	0.68	0.70	0.71
Water heating - Attached Houses	PJ	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27
Water heating - Apartments	PJ	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29
Water heating - Detached Houses	PJ	2.46	2.47	2.47	2.46	2.46	2.47	2.47	2.47	2.48
Water heating - Mobile Homes	PJ	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Air, Freight, All	MTKms	16.35	17.86	18.84	20.86	22.31	23.57	24.75	25.37	25.94
Air, Passenger, Domestic	MPKms	2,184.83	2,299.06	2,390.78	2,427.02	2,486.02	2,488.38	2,493.31	2,529.77	2,596.43
Air, Passenger, International	MPKms	2,283.78	2,494.99	2,631.41	2,914.16	3,117.17	3,293.44	3,457.83	3,544.53	3,623.67
Marine, generic	PJ	4.58	5.01	5.28	5.85	6.26	6.61	6.94	7.11	7.27
Road, Freight, Heavy Trucks	MTKms	4,548.04	4,968.64	5,240.32	5,803.41	6,207.70	6,558.72	6,886.11	7,058.76	7,216.36
Road, Freight, Medium Trucks	MTKms	150.47	164.39	173.38	192.01	205.38	217.00	227.83	233.54	238.75
Road, Freight, Light Trucks	MTKms	414.75	453.11	477.88	529.23	566.10	598.11	627.97	643.71	658.08
Road, Passenger, School Buses	MPKms	449.65	473.16	492.04	499.50	511.64	512.13	513.14	520.65	534.36
Road, Passenger, Intercity Buses	MPKms	100.13	105.36	109.57	111.23	113.93	114.04	114.27	115.94	118.99
Road, Passenger, Large Cars, Long distance	MPKms	623.11	655.69	681.85	692.19	709.01	709.69	711.09	721.49	740.50
Road, Passenger, Large Cars, Short distance	MPKms	761.58	801.40	833.37	846.01	866.57	867.39	869.11	881.82	905.06
Road, Passenger, Motorcycles	MPKms	67.97	71.52	74.38	75.50	77.34	77.41	77.56	78.70	80.77
Road, Passenger, Off road vehicles	PJ	3.07	3.23	3.36	3.41	3.50	3.50	3.51	3.56	3.65
Road, Passenger, Small Cars, Long distance	MPKms	1,875.39	1,973.44	2,052.17	2,083.28	2,133.92	2,135.95	2,140.18	2,171.48	2,228.69
Road, Passenger, Small Cars, Short distance	MPKms	2,292.14	2,411.98	2,508.21	2,546.23	2,608.12	2,610.60	2,615.77	2,654.03	2,723.96
Road, Passenger, Light Trucks	MPKms	4,411.72	4,642.38	4,827.58	4,900.76	5,019.89	5,024.66	5,034.61	5,108.24	5,242.83
Road, Passenger, Urban Buses	MPKms	284.68	299.57	311.52	316.24	323.93	324.24	324.88	329.63	338.31
Road, Passenger, Subways	MPKms	-	-	-	-	-	-	-	-	-
Rail, Freight	MTKms	-	-	-	-	-	-	-	-	-
Rail, Passenger	MPKms	-	-	-	-	-	-	-	-	-

Figure 57. Comparison of oil production levels in NL to the NEB forecast in the CENTRAL scenario

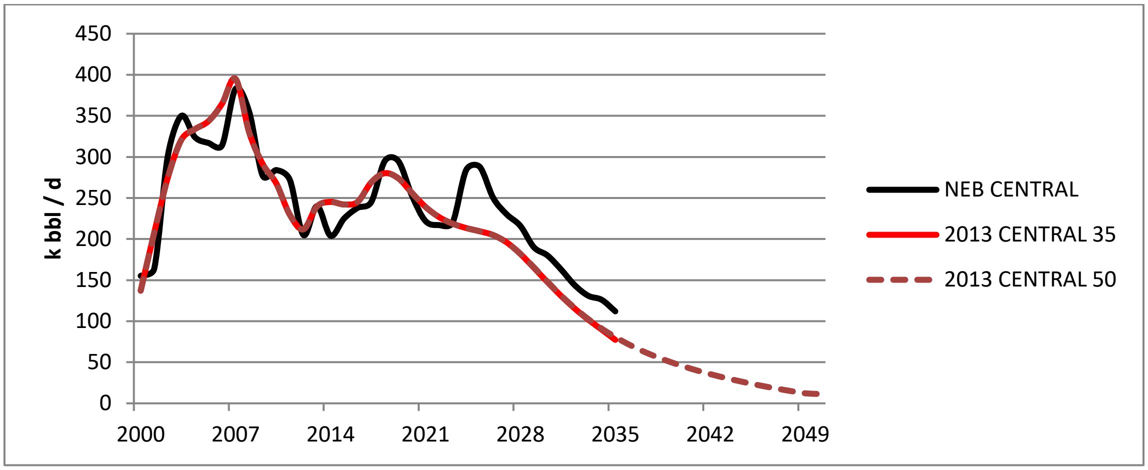


Figure 58. Comparison of oil production levels in NL to the NEB forecast in the HIGH scenario

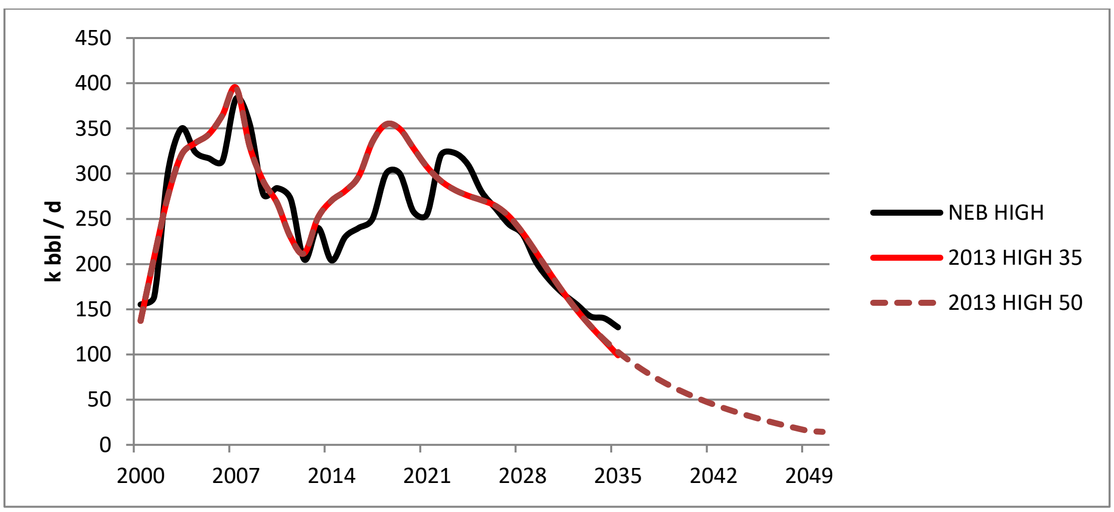


Figure 59. Comparison of oil production levels in NL to the NEB forecast in the LOW scenario

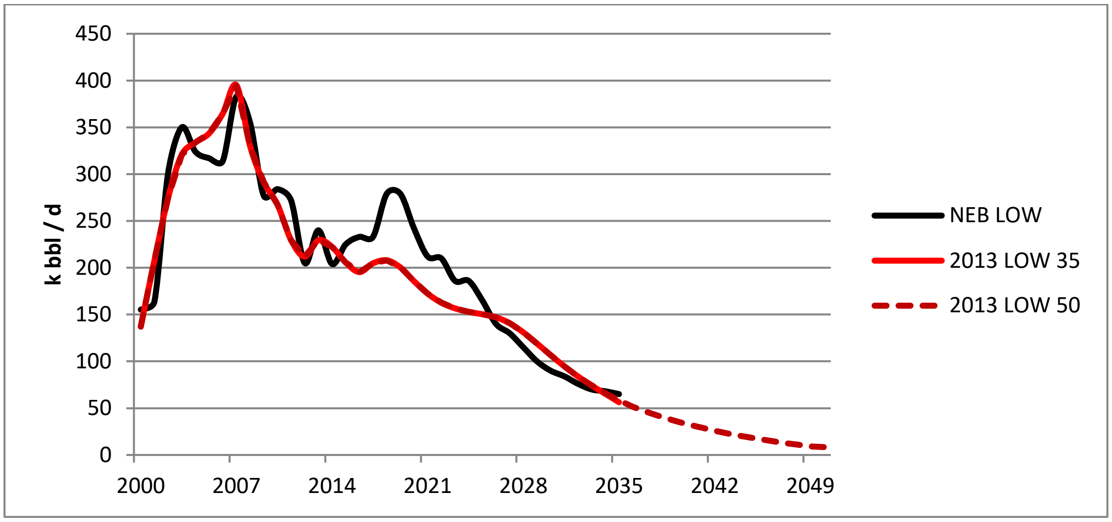


Figure 60. Oil imports by origin and by province in Eastern Canada in S2

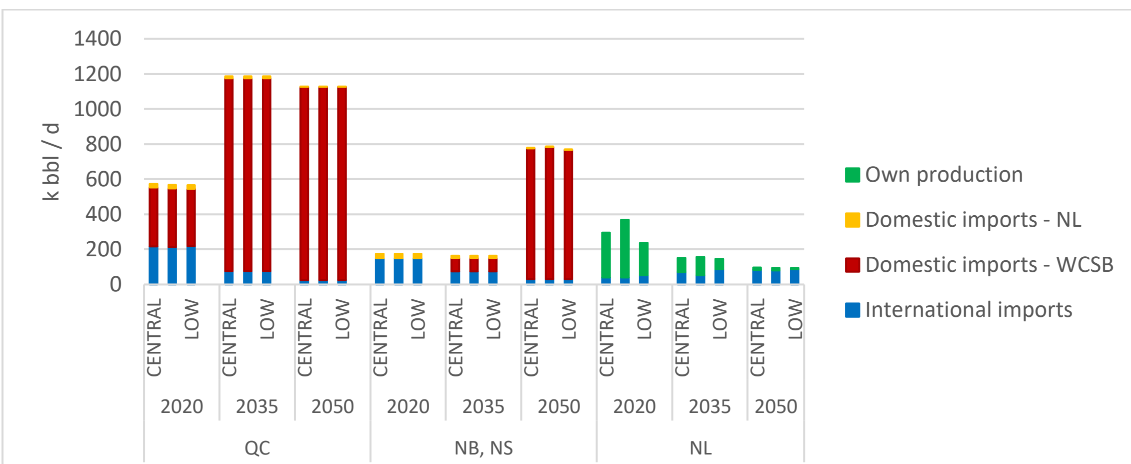


Figure 61. Oil imports by origin and by province in Eastern Canada in S3

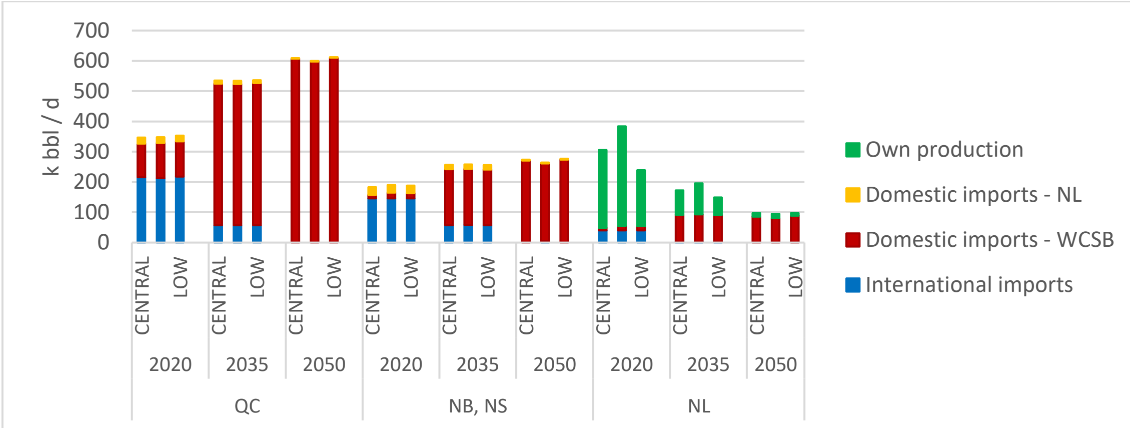


Figure 62. Oil imports by origin and by province in Eastern Canada in S4

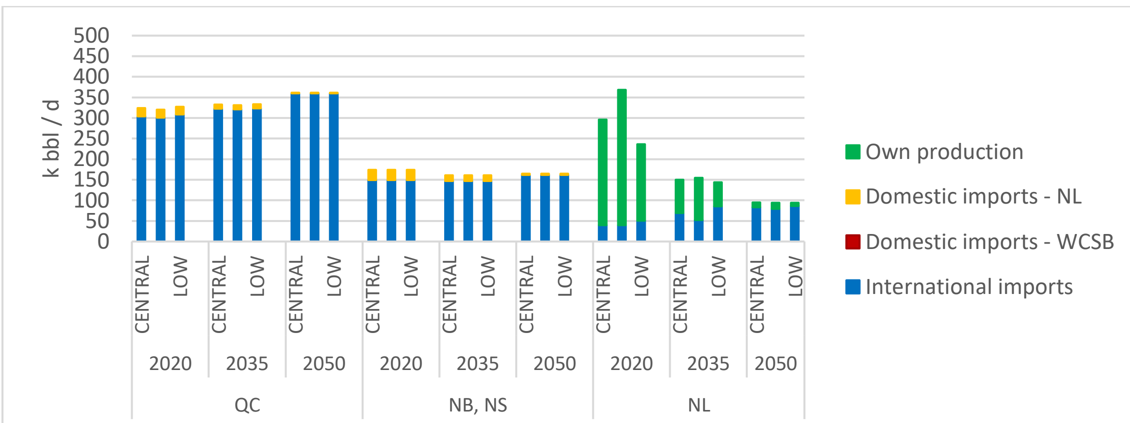


Figure 63. Oil demand by province in Eastern Canada in S2

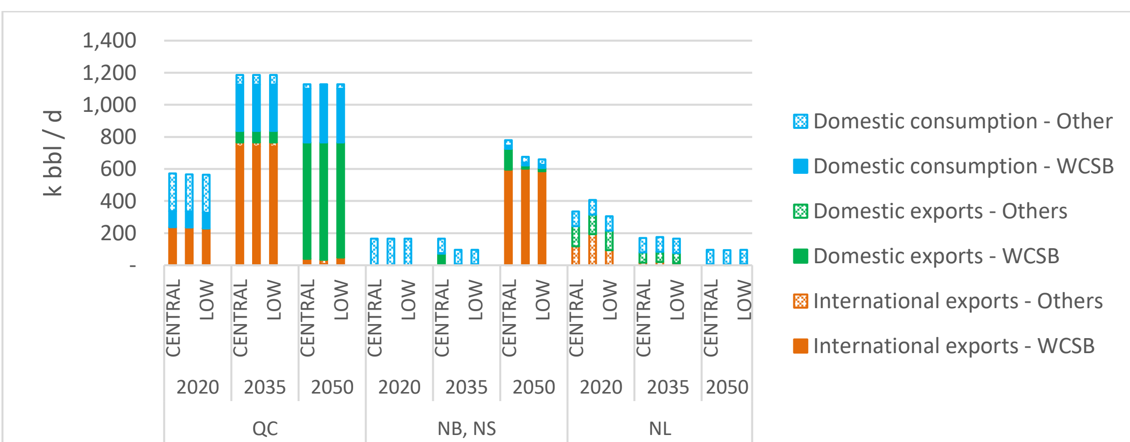


Figure 64. Oil demand by province in Eastern Canada in S3

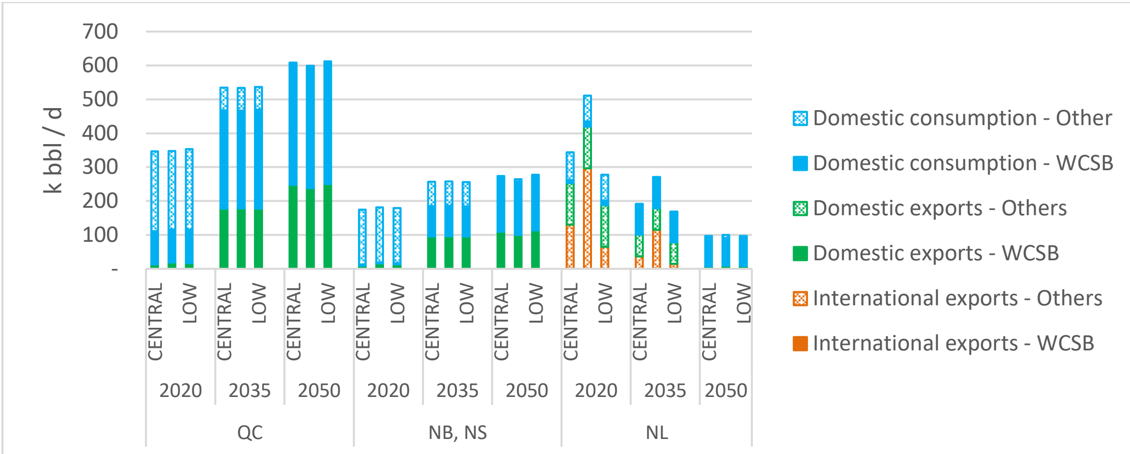
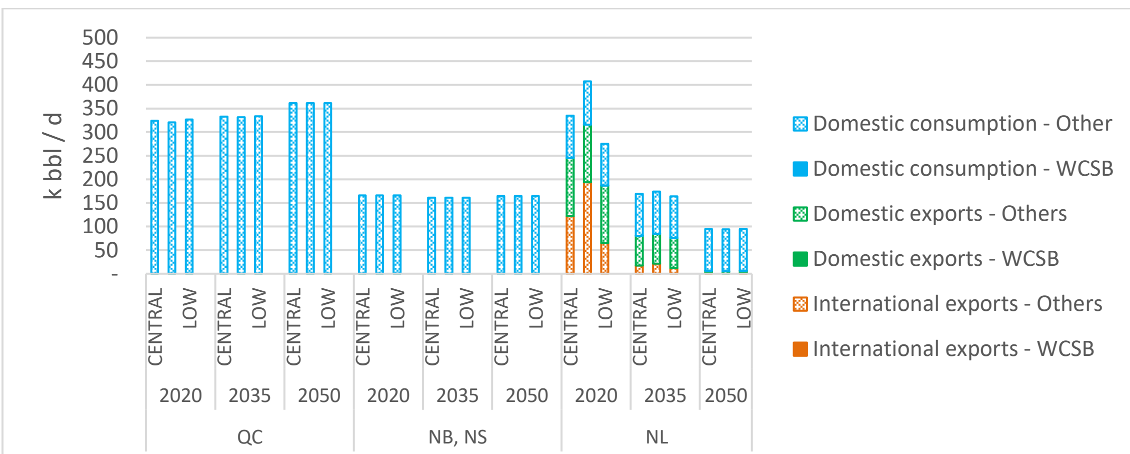


Figure 65. Oil demand by province in Eastern Canada in S4



General conclusion

We successfully developed a new framework that models the Canadian energy sector, with particular focus on the oil sector, looking to the details of the different types of conventional and unconventional oil production trends levels and reserves. We also analysed different trends of possible scenarios up to 2050. The analysis was done in detail at provincial level, considering how primary and secondary energy sources are generated, consumed, transformed and traded. A detailed study of quantity, price and emissions was also included. Our approach combined forecasting, linear programing and the use of macroeconomic information in a holistic approach, thanks to the use of a soft-link methodology that allows the integration, in one model, of economic and physical variables under a resource-constrained platform. Considering all the supply chain, (oil supply, consumption, distribution, extraction, and refining) this new framework combines diverse and specific modeling approaches with a solid integration of economic and physical variables. These advantages, combined with the use of macroeconomic information, are essential to improve the planning process and help with the investment decisions. We profited from the TIMES model for long-term energy and environmental policy analysis and from the forecasting model for short-term analysis.

More specifically, the use of the forecasting model was proposed to define oil production profiles by establishing a link between well count, oil price, and oil production. This approach combined the implementation of the Hubbert logistic function that takes into account the impact of the age of the producing wells. The model was also used to estimate the reserves, considering economic variables. We have applied our model to forecast a production profile for the Canadian oil sector to 2050, distinguishing between conventional and unconventional sources. According to our model, Canadian production will reach a peak around 2030 and Western oil sands will be the most important source. The model forecasts peak production of offshore developments in 2020, indicating that this could be another significant trend in Canadian oil production. We were able to determine interesting conclusions from the different data sets applied to determine the parameters such as the loss of the contribution from oil price. This observation can lead to further analysis such as the study of offshore investments in Newfoundland and how these investments should be in relation to the observed changes in oil prices.

We also show the importance of the development of TIMES model for Canada to define and analyze possible futures for the Canadian integrated energy system on the 2050 horizon, under different baselines corresponding to different oil prices and socio-economic growth trends. We have shown that the total Canadian final energy consumption is expected to increase by 43% on the 2050 horizon in the Reference scenario. The increase of the total final energy demand for 2050 varies from a 21% increase in the Fast scenario to a 8% decline in the Slow scenario, both compared to the Reference scenario. The effects on the fuel mix were also analysed. In all scenarios, oil products will continue to dominate the markets on the long term due to the transportation sector, although in a decreasing proportion over time in favour of electricity. Regarding the optimal energy production path we see a gradual replacement of onshore conventional oil & gas sources by unconventional and offshore sources through 2050 and a significant penetration of renewables in the electricity mix after 2035, due to increases in oil import prices and decreases in renewable technology costs.

More details and analysis was presented on the oil sector with the use of a TIMES model for Canada, under different exportation scenarios based on existing pipeline capacity expansion proposals and new pipeline projects to reach new local and international markets. Analysis of conventional and unconventional oil exports was done to understand the impacts on the crude oil production profiles and on final energy consumption mix. Results show that the exporting capacity will be an important driver for oil production levels in Canada. Outside the oil sector, impacts on the energy system are limited. In particular, final energy consumption patterns consider fossil fuels as the basis for the economy. Uncertainty about markets for oil producers impacts negatively the Canadian economy postponing major investments. Variations of oil prices on international markets have indeed major impacts on the Canadian oil sectors in addition to pipeline capacities.

Our research work concludes with the implementation of a soft-linking model framework, including a forecasting model and a TIMES model for Canada. This work was presented and applied to a specific case study to generate insights on: the domestic oil supply-demand dynamic in Canada under different economic growth scenarios and the impacts of different pipeline projects on the oil supply-demand dynamic in Eastern provinces, Newfoundland especially. The results of the optimization model suggest that the pipeline would be used at its maximum capacity starting around 2030 for both international exports and domestic uses. We also show the impact on production level. By blocking the access to Western Canadian oil in Newfoundland brings the offshore oil price up by 10$/bbl in 2035 and 4$/bbl in 2050. The results of the forecasting model show higher production levels between 5% and 14% on average for the 2013-2050 period using these oil prices compared with those of the National Energy Board. The results discussed in the report illustrate well the potential of the model framework to analyse such supply-demand dynamics and to provide insights on market trends. From the methodological side, this work takes the best from both optimization and forecasting models. From the forecasting approach we get the connection between price, quantity and infrastructure and the short-term insight to shape the business as usual case and the reserves related to economic variables. This approach is important for short-term analysis and strategic decisions. From optimization we get the connection between supply and demand, using a resource-constrained model and having more flexibility to handle different scenarios related to economic development. This approach is important to analyze competitive sources, strategies and medium and long-term analysis.

Our framework didn't work as expected when modeling the offshore production in Eastern Canada. More specifically we had issues obtaining the linear regressions to model well count, when using oil price and production as inputs. The main factor limiting the implementation was the scarce available data and the non-linear nature of the "average well". We also have limitations using the macroeconomic data, because we didn't have full direct access to the NALEM model and we needed to wait to obtain the requested results in order to perform each iteration.

The presented work should be seen as a first step toward a broader and deeper analysis to understand the economic implications of the evolution of the oil sector. Indeed, these are complex issues that would require more work in order to bring robust conclusions. Future work will allow improvement of this analysis from several points of view. In the case of the forecasting model, this could be improved by using a full time series approach as in Arpegis and implement it with well count instead of rig count. Then, extend the modifications to the Arpegis model, by adding the non-linear approach from our forecasting model that considers using the second calibration step and our aggregated logistic functions approach.

Additional improvements could come from extending the methodology to cover more aspects of the problem, refine data and assumptions to bring the definition of the problem closer to reality. Of interest will also be increasing the numbers of scenarios in order to analyse the problem in all its dimensions.

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