International Energy Agency

Energy Policies of IEA Countries

CANADA

2009 Review

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Canada, with its diverse and balanced portfolio of energy resources, is one of the largest producers and exporters of energy among IEA member countries. The energy sector plays an increasingly important role for the Canadian economy and for global energy security, as its abundant resource base has the potential to deliver even greater volumes of energy.

The federal, provincial and territorial governments of Canada are all strongly committed to the sustainable development of the country's natural resources and have a long-standing and informed awareness of the need for each to contribute to the development of the energy sector. Furthermore, the government of Canada seeks to achieve a balance between the environmentally responsible production and use of energy, the growth and competitiveness of the economy, and secure and competitively priced energy and infrastructure. Nonetheless, the long-term sustainability of the sector remains a challenge. Due to climatic, geographic and other factors, Canada is one of the highest per-capita CO_2 emitters in the OECD and has higher energy intensity than any IEA member country. A comprehensive national energy efficiency strategy, coupled with a coordinated climate change policy targeted at the key emitting sectors, is needed.

Carbon capture and storage (CCS) is a priority for the federal government and presents Canada with an opportunity to develop a new technology that can reduce greenhouse gas emissions on a large scale. The IEA recommends that Canada provide international leadership in the development of CCS technology.

This review analyses the energy challenges facing Canada and provides sectoral critiques and recommendations for further policy improvements. It is intended to help guide Canada towards a more sustainable energy future.

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INTERNATIONAL ENERGY AGENCY

The International Energy Agency (IEA), an autonomous agency, was established in November 1974. Its mandate is two-fold: to promote energy security amongst its member countries through collective response to physical disruptions in oil supply and to advise member countries on sound energy policy.

The IEA carries out a comprehensive programme of energy co-operation among 28 advanced economies, each of which is obliged to hold oil stocks equivalent to 90 days of its net imports. The Agency aims to:

- Secure member countries' access to reliable and ample supplies of all forms of energy; in particular, through maintaining effective emergency response capabilities in case of oil supply disruptions.
- Promote sustainable energy policies that spur economic growth and environmental protection in a global context – particularly in terms of reducing greenhouse-gas emissions that contribute to climate change.
- Improve transparency of international markets through collection and analysis of energy data.
- Support global collaboration on energy technology to secure future energy supplies and mitigate their environmental impact, including through improved energy efficiency and development and deployment of low-carbon technologies.
- Find solutions to global energy challenges through engagement and dialogue with non-member countries, industry, international organisations and other stakeholders.

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United Kingdom
United States

The European Commission also participates in the work of the IEA.

International Energy Agency

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EXECUTIVE SUMMARY AND KEY RECOMMENDATIONS

EXECUTIVE SUMMARY

Canada enjoys the advantage of a diverse and balanced portfolio of energy resources and is one of IEA's largest producers and exporters of energy. The importance of the energy sector for the Canadian economy, and for global energy security, has grown steadily over the last decade. The country's abundant resource base has the potential to deliver even greater volumes of energy. Nonetheless, like other energy-producing economies, Canada faces a number of challenges. The most significant of these relates to sustainability; Canada is one of the highest per-capita emitters in the OECD and has higher energy intensity, adjusted for purchasing power parity, than any IEA country, largely the result of its size, climate (*i.e.* energy demands), and resource-based economy. Conversely, the Canadian power sector is one of OECD's lowest emitting generation portfolios, producing over three-quarters of its electricity from renewable energy sources and nuclear energy combined.

POLICY FRAMEWORK

An understanding of the roles of Canada's provinces and territories, and their ability to influence and shape energy policy formation and implementation, is an important feature of Canadian energy policy analysis. Respect for jurisdictional authority and the role of the provinces form an important pillar of energy policy.

A key feature of the Canadian context is that provinces, jurisdictions that receive their power and authority directly from the Constitution Act of 1867, are owners of their ground resources apart from those located in aboriginal lands and some federal lands. Provincial governments are the direct managers of most of Canada's resources and have primary responsibility for shaping policies implemented in their jurisdictions. Unlike the provinces, the territories of Canada have no inherent jurisdiction. They do not own their ground resources, but have some management responsibility. Policy co-ordination between the federal and the provincial governments takes place through formal high-level committees and informal contacts and consultations.

Three key underlying principles of Canadian energy policy are: market orientation; respect for jurisdictional authority and the role of the provinces; and, where necessary, intervention in markets to achieve specific policy objectives. Canadian energy policy relies on competitive markets to determine supply, demand, prices, and trade, and is guided by a drive for cleaner production and use of energy. The government of Canada seeks to achieve a balance between the environmentally responsible production and use of energy, the growth and competitiveness of the economy, and secure and competitively priced energy and infrastructure.

SOUND RESOURCE POLICIES

The federal, provincial and territorial governments of Canada share a strong commitment to the sustainable development of the country's natural resources and have a long-standing and informed awareness of the dangers posed by climate change and the need for each to contribute to the development of a long-term solution.

In many parts of Canada, the regulatory framework in potential natural gas- and oil-producing regions appears complex. This is further complicated by the requirement to negotiate and settle aboriginal land claims. A repeated criticism is that the environmental outcomes of the energy project approval process are unpredictable and untimely. The establishment of the Major Projects Management Office is a helpful step towards a more predictable and timely review process. As a general principle, the aim should be that environmental evaluation by all regulatory bodies should be carried out on the basis of a single environmental assessment.

One of the greatest challenges facing Canada is its ability to continue to develop its vast unconventional oil resources in a sustainable manner. In this regard, the forecast increase in production from the Alberta oil-sands poses the greatest test. Canada must take care to develop this resource without a disproportionate increase in emissions and incurrence of excessive emissions penalties while at the same time managing the broader environmental impacts of new energy developments such as water management, post-mining reclamation and tailing ponds.

There are a number of strategic investment issues facing the upstream oil and gas industry, one of which is exploring the possibility of expanding international markets beyond the United States, the only significant market for Canada's oil and natural gas exports at present. Policy makers and industry must therefore start to focus on identifying new export markets and on the infrastructure needed to access these markets. The federal government should continue to support this process and keep under review the impact that taxation and regulatory policies may have on the outcome. Furthermore, it should also maintain its broad policy approach in which investment decisions are left to the private sector.

Canada's coal reserves are abundant, constituting by far the largest hydrocarbon reserves in a resource-rich country. Accounting for just over 10% of global coking coal exports, Canada's coal exports add an important element of competition to what is otherwise a relatively concentrated market by providing an alternate source of coking coal for consumers around the world.

In the electricity industry, a major challenge facing the sector is the federal government's commitment to ensure that 90% of electricity needs come from non-emitting sources by 2020. This is an increase of 15% on present levels; therefore, approximately 110 TWh of carbon-emitting output must be displaced. At present, renewable energy accounts for 61% of Canada's electricity output, mostly hydropower, while nuclear energy proves a further 15%. To bridge this potential long-term capacity shortfall, the federal government will have to: work very closely with provincial and territorial authorities in co-ordinating the planning and authorising new generation facilities; commit to long-term, effective and predictable support mechanisms for renewable energy; and proceed with the restructuring of the nuclear industry

CLIMATE CHANGE

The government of Canada was unable to meet its obligations under the Kyoto Protocol, and thus developed an alternative approach to climate change policy, the *Turning the Corner* framework, which was published in 2007. Since then, a number of factors, such as the global economic downturn and a change of government, have led the federal government to place its previous climate change policies, including the *Turning the Corner*, under review, albeit while continuing to pursue the regulation of GHG-emitting industrial facilities.

We strongly encourage the federal government to maintain its very close dialogue with the United States and to commit to participate in any agreed international solution. The announcement, in February 2009, of the commencement of a Clean Energy Dialogue between Canada and the United States with the intention of developing a possible future cap-and-trade system and the development and deployment of clean energy technologies was a very welcome step. The government should build on this momentum and seek further opportunities for engagement and climate change policy co-ordination while continuing to develop its own initiatives.

Furthermore, on 30 January 2010, Canada announced the submission of its 2020 emissions reduction target under the Copenhagen Accord. Canada's 2020 target, an economy-wide 17% reduction from 2005 emissions levels, is aligned with the United States target, and is subject to adjustment to remain consistent with the United States target.

CARBON CAPTURE AND STORAGE

Carbon capture and storage (CCS) is a priority for the federal government and presents Canada with an opportunity to develop a technology that can reduce greenhouse gas (GHG) emissions on a large scale. Western Canada in particular represents a world-class opportunity to advance CCS, with a concentration of large final emitters (*e.g.* oil-sands and coal-based power generation) in close proximity to excellent storage sites. Given the high costs and uncertainties associated with CCS, GHG policies and/or carbon prices alone will not advance this technology. Canada, therefore, needs to develop an integrated long-term policy that brings the technology from large-scale demonstration to commercialisation via economic and/or regulatory incentives.

Various measures to encourage or mandate GHG mitigation, including CCS, exist or are being developed at provincial level. As with other aspects of climate change policy, further work will need to be undertaken by the federal and provincial governments to ensure consistency and compatibility of any CCS-related obligations on industrial entities. Commendably, the federal government and several provinces are taking steps to promote CCS technology and the government of Canada has committed over CAD 1 billion in funding for CCS towards large-scale CCS demonstration projects through various programmes.

Canada should continue to maintain its high profile and leadership in international efforts to promote and implement CCS and then take the next important step: to commit funding to the implementation of projects and advance their construction.

ENERGY EFFICIENCY

Canada has higher energy intensity, adjusted for purchasing power parity (PPP), than any other IEA country. Final energy consumption has grown continuously over the past decade, though at a lower rate than the economy as a whole. Energy intensity levels, although improving, are largely related to Canada's high concentration of output in energy-intensive sectors, its relatively cold climate, large distances travelled and a high standard of living, with minimal constraints on space occupation.

Canada is committed to working to improve and increase energy efficiency. In August 2008, the provinces and territories collectively committed to achieving a 20% increase in energy efficiency by 2020, largely through improvements to building codes, broader regulation of energy-consuming products, green building policies for new government-funded facilities, and home energy audits and retrofit assistance. In addition, federal and provincial or territorial governments are collaborating in different ways to achieve combined energy efficiency objectives.

Across sectors, co-operation between provincial and federal energy ministers on developing a national energy efficiency action plan could be further strengthened. National targets and/or harmonised measurements and timeframes to maximise opportunities for energy savings, with a particular emphasis on road transport and buildings, should be an important feature of this plan.

KEY RECOMMENDATIONS

The government of Canada should:

- *Develop a co-ordinated climate change policy targeted on the key emitting sectors, including specific cap-and-trade proposals, and actively participate in any forthcoming international agreement.*
- *Implement a comprehensive national energy efficiency strategy, focused on reducing energy intensity, with an explicit emphasis on policies in the road transport sector and buildings sector.*
- *Maintain Canada's high profile and leadership in CCS efforts internationally and prepare a national strategy for the implementation of CCS, including the construction of full-scale demonstration facilities as soon as possible.*
- *Continue to streamline upstream oil and natural gas environmental regulatory processes, develop new natural gas- and oil-export markets and the infrastructure needed to facilitate supply and access to these markets.*

SOMMAIRE ET RECOMMANDATIONS*

Le Canada bénéficie d'un portefeuille de ressources énergétiques diversifié et équilibré et est un des principaux producteurs et exportateurs d'énergie des pays membres de l'Agence internationale de l'énergie (AIE). L'importance du secteur de l'énergie pour l'économie canadienne et pour la sécurité énergétique mondiale s'est accrue de façon constante au cours de la dernière décennie. L'abondance des ressources du pays permettra de fournir des volumes encore plus grands d'énergie. Néanmoins, comme d'autres pays producteurs d'énergie, le Canada fait face à un certain nombre de défis dont le plus important est celui de la durabilité; le Canada est un des plus gros émetteurs de gaz à effet de serre (GES) par habitant au sein de l'OCDE, et son intensité énergétique, en parité de pouvoir d'achat, est supérieure à celle de tout autre pays membre de l'AIE, principalement en raison de sa taille, de son climat (c'est-à-dire de sa demande en énergie) et de son économie fondée sur les ressources nationales. À l'inverse, le secteur de l'énergie du Canada est l'un des portefeuilles de production d'énergie dont les émissions sont les plus faibles de tous les pays de l'OCDE. Il produit plus des trois quarts de son électricité à partir de sources à la fois d'énergie renouvelable et d'énergie nucléaire.

LE CADRE STRATÉGIQUE

La compréhension du rôle des provinces et des territoires du Canada, ainsi que de leur aptitude à influer sur l'élaboration et la mise en œuvre des politiques énergétiques, est un aspect important de l'analyse des politiques énergétiques du Canada. Le respect des compétences et du rôle des provinces constitue un pilier important de la politique énergétique.

Une caractéristique essentielle du contexte canadien est le fait que les provinces, dont les pouvoirs et les compétences découlent directement de la *Loi constitutionnelle de 1867*, sont propriétaires de leurs propres ressources terrestres, à l'exception de celles qui se trouvent sur des terres autochtones et certaines terres fédérales. Les gouvernements provinciaux sont les gestionnaires directs de la plupart des ressources du Canada et sont les principaux responsables de l'élaboration des politiques mises en œuvre sur leur territoire. Contrairement aux provinces, les territoires du Canada n'ont aucune compétence inhérente. Ils ne sont pas propriétaires de leurs ressources terrestres, mais ils sont en partie responsables de leur gestion. La coordination stratégique entre les gouvernements fédéral et provinciaux est assurée par le biais de comités officiels de haut niveau ainsi que de rencontres et consultations informelles.

* This translation was provided to the IEA by the government of Canada.

La politique énergétique du Canada compte trois grands principes sous-jacents : l'orientation des marchés, le respect de l'autorité compétente et du rôle des provinces et, au besoin, l'intervention dans les marchés afin d'atteindre des objectifs stratégiques précis. La politique énergétique du Canada compte sur les marchés concurrentiels pour déterminer l'offre, la demande, les prix et les échanges commerciaux. Son orientation est fondée sur la production et l'utilisation écologiques de l'énergie. Le gouvernement du Canada cherche à assurer un équilibre entre la production et l'utilisation d'énergie d'une manière respectueuse de l'environnement, la croissance et la compétitivité de l'économie, une énergie et une infrastructure fiables et à des prix concurrentiels.

POLITIQUES JUDICIEUSES EN MATIÈRE DE RESSOURCES

Le gouvernement fédéral, celui des provinces et territoires du Canada partagent un engagement solide à l'égard du développement durable des ressources naturelles du pays. Ils sont conscients des dangers que présentent les changements climatiques et l'obligation de chaque gouvernement de contribuer à l'élaboration d'une solution à long terme.

Dans de nombreuses parties du Canada, le cadre réglementaire semble complexe dans les régions qui ont un potentiel de production de pétrole et de gaz naturel. Il est compliqué d'autant par l'exigence de négociations et d'accords relatifs aux revendications territoriales des autochtones. Le fait que les résultats environnementaux du processus d'approbation de projets énergétiques sont imprévisibles et inopportuns fait l'objet de critiques répétées. La création du Bureau de gestion des grands projets est une étape utile vers des processus d'examen prévisibles et opportuns. De façon générale, il faudrait que les différentes évaluations environnementales menées par tous les organismes de réglementation soient réduites à une seule et unique évaluation environnementale.

Un des principaux défis que doit relever le Canada est sa capacité de poursuivre la mise en valeur de ses vastes ressources pétrolières originales d'une manière durable. À cet égard, la prévision d'une hausse de la production tirée de l'exploitation des sables bitumineux de l'Alberta présente le plus grand défi. Le Canada doit s'attacher à mettre cette ressource en valeur sans accroître ses émissions de façon démesurée et sans encourir de pénalités pour émissions excessives, tout en gérant les effets environnementaux cumulés des nouveaux projets énergétiques, comme la gestion des eaux, la remise en état des terrains après les travaux d'exploitation minière et les bassins à résidus.

Le secteur amont de l'industrie pétrolière et gazière fait face à un certain nombre de problèmes liés aux investissements stratégiques, notamment celui de l'exploration des possibilités d'élargir les marchés internationaux au-delà des États Unis, le seul marché important pour le pétrole et le gaz naturel du Canada à l'heure actuelle. Les décideurs et l'industrie doivent donc dès maintenant se concentrer sur la détermination de nouveaux marchés d'exportation et sur l'infrastructure nécessaire pour y avoir accès. Le gouvernement fédéral devrait continuer de soutenir ce processus et surveiller l'incidence des politiques fiscales et réglementaires sur les résultats. De plus, le gouvernement fédéral devrait maintenir son approche stratégique générale dans le cadre de laquelle les décisions en matière d'investissement relèvent du secteur privé.

Les réserves de charbon du Canada sont abondantes et constituent les réserves d'hydrocarbures les plus importantes dans un pays riche en ressources. Les exportations de charbon du Canada, qui comptent pour un peu plus de 10 % des exportations mondiales de charbon cokéfiable, ajoutent un élément concurrentiel important à ce qui est autrement un marché relativement concentré, en fournissant une nouvelle source de charbon cokéfiable pour les consommateurs du monde entier.

Dans l'industrie de l'électricité, un défi important à relever est celui de l'engagement du gouvernement fédéral de satisfaire les besoins en électricité à hauteur de 90 % à partir de sources sans émission d'ici 2020. Cet objectif correspond à une hausse de 15 % par rapport au niveau actuel. Par conséquent, environ 110 TWh de production avec émissions doivent être remplacés. À l'heure actuelle, l'énergie renouvelable compte pour 61 % de l'électricité produite au Canada, principalement sous forme d'hydroélectricité, tandis que l'énergie nucléaire en fournit environ 15 %. Pour combler ce possible déficit de capacité à long terme, le gouvernement fédéral devra collaborer étroitement avec les provinces et les territoires pour coordonner la planification et l'autorisation de nouvelles installations de production, s'engager à prendre les mesures de soutien attendues, efficaces et à long terme en ce qui concerne les énergies renouvelables et veiller à la restructuration de l'industrie nucléaire.

CHANGEMENTS CLIMATIQUES

Le gouvernement du Canada n'ayant pu respecter ses engagements à l'égard du Protocole de Kyoto, il a donc élaboré une nouvelle approche pour la politique de lutte contre les changements climatiques : le plan *Prendre le virage* publié en 2007. Depuis, un certain nombre de facteurs, comme la crise économique mondiale et un changement de gouvernement, ont amené le gouvernement fédéral à revoir ses politiques relatives aux changements climatiques, y compris le plan *Prendre le virage*, tout en poursuivant la réglementation des installations industrielles qui émettent des GES.

Nous encourageons vivement le gouvernement fédéral à entretenir un dialogue étroit avec les États-Unis et à s'engager à participer à toute solution acceptée à l'échelle internationale. L'annonce, en février 2009, de l'ouverture du dialogue sur l'énergie propre entre le Canada et les États-Unis, dans le but d'élaborer un système possible de plafonnement et d'échange ainsi que d'élaborer et déployer des technologies d'énergie propre, est un pas dans la bonne direction. Le gouvernement devrait poursuivre sur cette lancée et rechercher d'autres occasions de participation et de coordination des politiques de lutte contre les changements climatiques tout en continuant à élaborer ses propres initiatives.

Le 30 janvier 2010, le Canada annonçait son objectif de réduction des gaz à effet de serre conformément à l'accord conclu lors du Sommet de Copenhague. L'objectif à l'horizon 2020 – une réduction globale de 17% par rapport aux émissions de 2005 – s'aligne sur l'objectif visé par les Etats-Unis. Il est susceptible d'être corrigé pour rester conforme à l'objectif des Etats-Unis.

CAPTAGE ET STOCKAGE DU CARBONE

Le captage et stockage du carbone (CSC) est une priorité pour le gouvernement fédéral. Il offre au Canada une occasion d'élaborer une technologie qui peut réduire les émissions de GES à grande échelle. L'Ouest canadien, en particulier, offre une occasion unique à l'échelle mondiale de promouvoir le CSC, compte tenu de la concentration de grands émetteurs finaux (par exemple les producteurs d'électricité à partir des sables bitumineux et du charbon) à proximité d'excellents sites de stockage. Compte tenu des incertitudes et des coûts élevés liés au CSC, les politiques en matière de gaz à effet de serre ou les prix du carbone ne suffiront pas à faire progresser cette technologie. Le Canada doit donc élaborer une politique intégrée à long terme qui fasse passer la technologie du stade de démonstration à grande échelle au stade de commercialisation par le biais d'incitatifs économiques et réglementaires.

Diverses mesures visant à encourager ou à imposer l'atténuation des GES, y compris le CSC, existent déjà ou sont en voie d'élaboration au niveau provincial. Comme pour d'autres aspects de la politique sur les changements climatiques, les gouvernements fédéral et provinciaux devront engager d'autres travaux pour assurer l'uniformité et la compatibilité de toute mesure imposée aux entités industrielles en matière de CSC. Le gouvernement fédéral et plusieurs provinces prennent des mesures pour promouvoir la technologie de CSC. Il faut les en féliciter. Le gouvernement fédéral a versé plus d'un milliard de dollars canadiens pour le financement de projets de démonstration à grande échelle du CSC dans le cadre de divers programmes.

Le Canada devrait maintenir son rôle très visible et son leadership dans les efforts internationaux visant à promouvoir et mettre en œuvre le CSC. Il devrait ensuite passer à la prochaine étape importante: financer la réalisation de projets et faire progresser les travaux de construction.

EFFICACITÉ ÉNERGÉTIQUE

L'intensité énergétique du Canada, ajustée en fonction de la parité du pouvoir d'achat, est supérieure à celle de tout autre pays membre de l'AIE. La consommation finale d'énergie a augmenté de façon continue au cours de la dernière décennie, mais moins vite que l'économie en général. Les niveaux d'intensité énergétique, bien qu'en voie d'amélioration, dépendent grandement de la forte concentration d'industries dans les secteurs à forte intensité d'énergie, du climat relativement froid du pays, des grandes distances à parcourir et du haut niveau de vie avec des contraintes minimales en termes d'espace.

Le Canada est déterminé à améliorer et à accroître son efficacité énergétique. En août 2008, les provinces et les territoires se sont collectivement engagés à augmenter de 20 % leur efficacité énergétique d'ici 2020, principalement par le biais d'améliorations aux codes du bâtiment, d'une réglementation plus générale des produits énergivores, de politiques de construction vertes pour les nouveaux bâtiments financés par le gouvernement, d'audits de consommation d'énergie par habitation et d'une aide à la rénovation. De plus, les gouvernements fédéral, provinciaux et territoriaux collaborent de différentes façons pour atteindre des objectifs communs en matière d'efficacité énergétique.

Dans tous les secteurs, la coopération entre les ministres de l'Énergie aux niveaux fédéral et provincial dans l'élaboration d'un plan d'action national pour l'efficacité énergétique pourrait être renforcée. Des objectifs nationaux ou des mesures et échéanciers harmonisés visant à maximiser les possibilités d'économies en énergie, avec un accent particulier sur le transport routier et les bâtiments, devraient constituer un élément important de ce plan.

RECOMMANDATIONS

Le gouvernement du Canada devrait prendre les mesures suivantes:

- *Élaborer une politique coordonnée de lutte contre les changements climatiques ciblée sur les principaux secteurs émetteurs, y compris des propositions spécifiques de plafonnement et d'échange, et participer activement à tout accord international futur.*

- *Mettre en œuvre une stratégie nationale générale en matière d'efficacité énergétique, centrée sur la réduction de l'intensité énergétique, en accordant une attention particulière aux politiques dans les secteurs du transport routier et des bâtiments.*

- *Maintenir le rôle très visible du Canada et son leadership en matière de captage et stockage du carbone à l'échelle internationale, et préparer une stratégie nationale pour la mise en œuvre du CSC, y compris le lancement des travaux de construction d'installations de démonstration à dimensions réelles dès que possible.*

- *Poursuivre la rationalisation des processus de réglementation environnementale du secteur amont de l'industrie pétrolière et gazière, exploiter de nouveaux marchés d'exportation pour le pétrole et le gaz naturel, et construire l'infrastructure nécessaire pour faciliter l'approvisionnement de ces marchés et l'accès à ceux-ci.*

PART I

POLICY ANALYSIS

Figure 1
Map of Canada

The boundaries and names shown and the designations used on maps included in this publication do not imply official endorsement or acceptance by the IEA.

GENERAL ENERGY POLICY

COUNTRY OVERVIEW

Canada, a parliamentary democracy and constitutional monarchy, is a federation of ten provinces and three territories. The Parliament of Canada, located in the capital Ottawa, consists of an elected House of Commons and an appointed Senate. Canada has two official languages, French and English.

Canada is the world's second-largest country by total area and shares land borders with the United States to the south and north-west. The fifth-largest energy producer in the world, Canada is resource-rich; energy plays a significant role in the economy and in trade. The country is one of the OECD's largest producers and exporters of natural gas, oil and uranium.

The population of Canada is approximately 33.5 million people. Canada experienced a higher rate of population growth (5.4%) than any other G8 country between 2001 and 2006, mostly owing to international migration. The vast majority of the Canadian population, nearly 25 million people, is concentrated in urban areas. According to the 2009 United Nations Human Development Index, Canada has the fourth-highest standard of living in the world.

THE ECONOMY

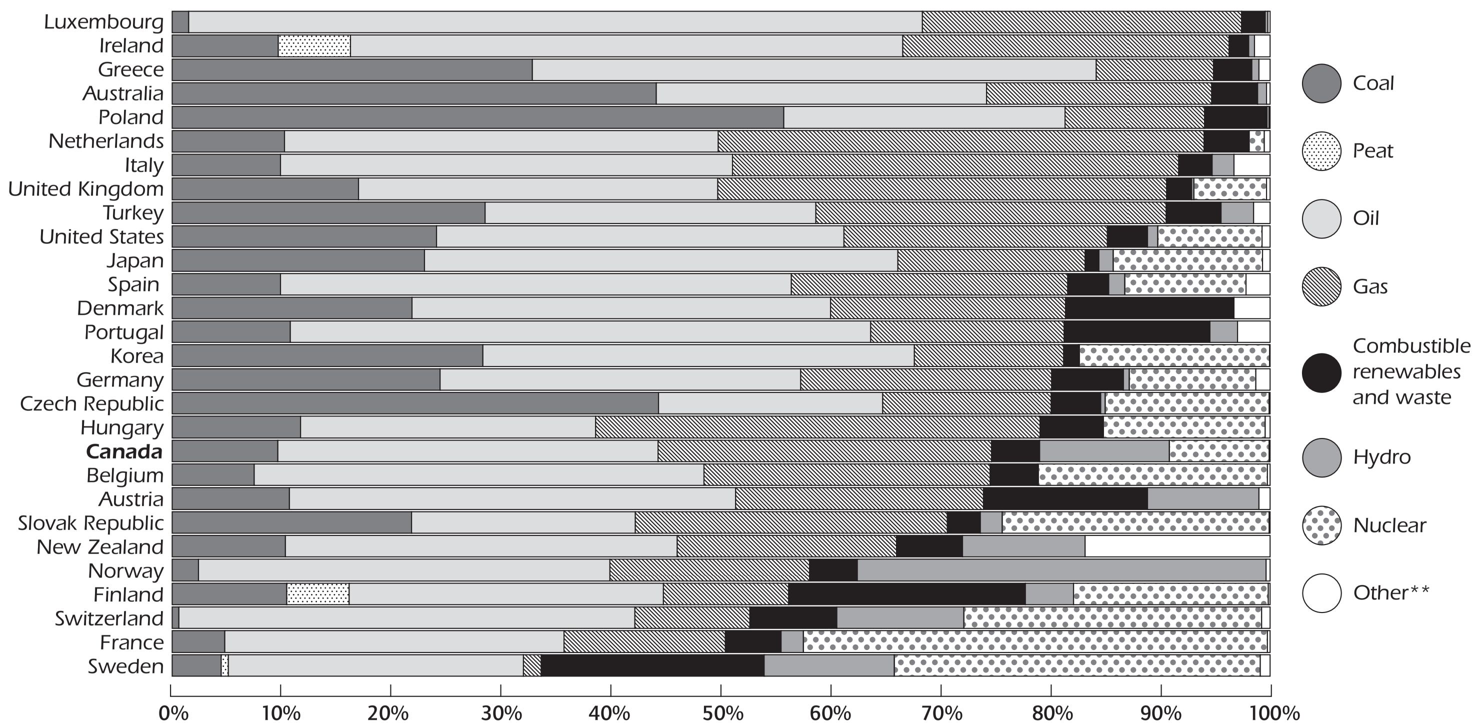
Canada is one of the largest OECD economies. In the period 2004-2007, real gross domestic product (GDP) grew by almost 21%.[1] The energy sector makes a significant contribution to the economy. It accounted for approximately 6.8% of GDP and the direct employment of 360 000 people or 2% of the Canadian workforce in 2008.[2]

Recognising the challenges faced by the present economic climate, Canada's 2009 Budget introduced an Economic Action Plan to provide almost CAD 30 billion in support to the economy. The stimulus package seeks to encourage economic growth and to help Canadians who are most affected by the global recession.[3] Though a fiscal deficit is projected for the next two years, it is expected that the economy will return to surplus and that Canada will lead the G8 in terms of economic growth in 2010.

1. In United States dollars, current prices and purchasing power parities.
2. *Canadian Energy Overview 2008, An Energy Market Assessment*, May 2009, National Energy Board.
3. *OECD Economic Outlook No. 85 – Canada*, 24 June 2009.

Figure 2

Total Primary Energy Supply in IEA Member Countries, 2008*



* estimates.

** includes geothermal, solar, wind, and ambient heat production.

Source: *Energy Balances of OECD Countries*, IEA/OECD Paris, 2009.

ENERGY SUPPLY AND DEMAND

SUPPLY

Canada has a diversified and balanced portfolio of energy resources, with great potential for further supply development. Total primary energy supply (TPES) in 2008 was 272.7 million tonnes of oil equivalent (Mtoe). This represents a slight fall from 2007 (269.4 Mtoe) and 2006 (269.2) levels. Canada relies on fossil fuels (85%) for almost all of its energy supply. The country is among the world's largest producers of oil, natural gas, hydroelectricity and uranium and is a net exporter of oil, natural gas, coal and uranium.

Production of oil has increased by almost 70% since 1990 largely on the back of increased exports to the United States. Proven Canadian oil reserves are estimated at 175.2 billion barrels; the vast majority of these reserves come from unconventional sources.[4] Remaining marketable natural gas reserves are estimated at 1 754 billion cubic metres (bcm).

Canada is one of the world's largest exporters of coking coal, mainly to Japan, and is the world's leading producer of uranium, accounting for roughly one-third of total global output. Exports of uranium are chiefly to the United States, the European Union and Japan.

Canada also produces large volumes of electricity from hydropower; in 2008 it produced 372 TWh of power or 58% of total gross electricity output. Electricity production from wind power was just 3 TWh in 2008, roughly the same as the previous year but a tenfold increase since 2000. In general, non-hydro renewable energies play a small but increasing role in the energy mix.

DEMAND

Total final consumption (TFC) of energy in 2008 was 207 Mtoe, a slight increase from the previous year (205 Mtoe). Energy demand has increased by 35% between 1990 and 2007 and is predicted to increase by 25% between 2007 and 2020. Demand is increasing in most sectors, with the strongest growth in the industrial sector.

Canadians improved the efficiency of their energy use by nearly 16% between 1990 and 2005. Nevertheless, overall energy use rose by almost 22% over the same period, and energy use per capita, or per unit of GDP, remains high relative to other countries. Canada's aggregate energy intensity decreased by around 1.8% per year from 1990 to 2006 and most of this decrease can be attributed to increases in energy efficiency rather than to changes in economic activity or structure.

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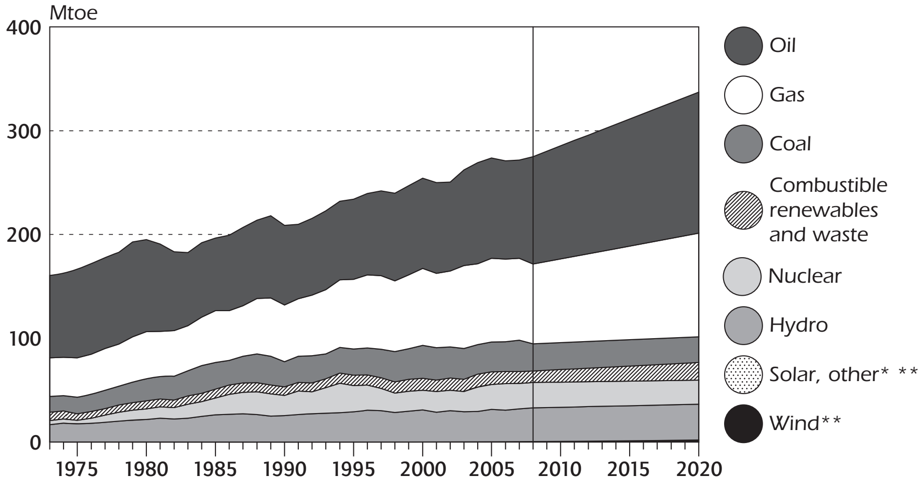
4. Proven oil reserves are calculated as follows: the total *in situ* and minable remaining established reserves for crude bitumen is 170.4 billion barrels (Source: *Alberta Energy Resources Conservation Board, Alberta's Energy Reserves 2008 and Supply/Demand Outlook 2009-2018*, June 2009) and conventional oil reserves are estimated as 4.8 billion barrels (Source: Statistical Handbook for Canada's Upstream Petroleum Industry, Canadian Association of Petroleum Producers, November 2009).

The road transport sector is the largest single energy consuming sector, followed by the residential and commercial and public services sector. Energy consumption in the transport sector was 4% higher in 2007 than in 2008.

Figure 3

Total Primary Energy Supply, 1973 to 2020



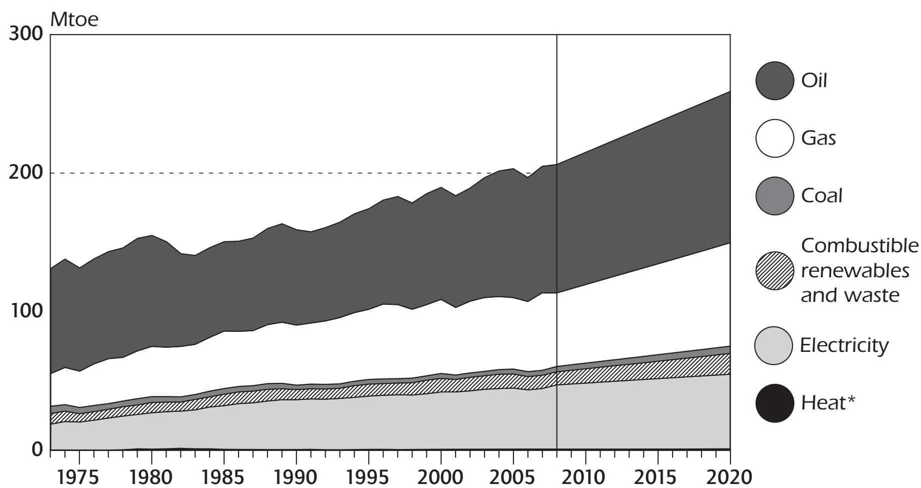
* other includes tide and wave.

** negligible.

Sources: *Energy Balances of OECD Countries*, IEA/OECD Paris, 2009 and country submission.

Figure 4

Total Final Consumption by Source, 1973 to 2020



* negligible.

Sources: *Energy Balances of OECD Countries*, IEA/OECD Paris, 2009 and country submission.

ENERGY ADMINISTRATION AND INSTITUTIONS

OVERVIEW

Canada has a federal government, ten provincial governments and three territorial governments. An understanding of the roles of each and their ability to influence and shape energy policy formation and implementation is critical to any analysis of Canadian energy policy.

There is no overall federal legislative framework for sector regulation. A key feature of the Canadian context is that provinces are owners of their ground resources apart from resources located in aboriginal lands and some federal lands such as national parks. The provinces have primary responsibility for shaping policies implemented in their jurisdictions. Territories do not own their ground resources, but do have some management responsibility, especially in the Yukon. In most cases, offshore areas are also considered federal jurisdiction, but the federal government shares management responsibility with Newfoundland and Labrador, and Nova Scotia.

Policy co-ordination between federal and the provincial governments takes place through formal high-level committees and informal contacts and consultations. At the highest level, the Council of Energy Ministers, comprising all provincial, territorial and federal energy ministers, meets annually to assemble and discuss the challenges and opportunities that face the energy sector.

The Constitution of Canada grants the federal government authority over international trade and commerce. This includes the construction and operation of international transmission lines and exports of electricity.

Federal energy policy is shared between Natural Resources Canada and the National Energy Board. The nuclear industry is regulated by the Canadian Nuclear Safety Commission. Jurisdiction relating to aboriginal peoples or First Nations, Inuit, Métis and northern communities, rests with the federal government.

NATURAL RESOURCES CANADA

Natural Resources Canada (NRCan) was created by an Act of Parliament in 1994 and is the lead agency on energy policy for the government of Canada. NRCan seeks to enhance the responsible development and use of Canada's natural resources and the competitiveness of Canada's natural resources products. NRCan employs about 4 200 people and has a budget of approximately CAD 1.1 billion (2009/10). It is one of the largest science-based departments in the federal government, specialising in the sustainable development and use of natural resources – energy, minerals and metals, forests – and in earth sciences.

The Energy Sector at NRCan is the lead on overall energy policy for the government of Canada. It is comprised of five branches: the Electricity Resources Branch (ERB), the Energy Policy Branch (EPB), the Petroleum Resources Branch (PRB), the Office of Energy Efficiency (OEE) and the Office of Energy Research and Development (OERD). The clean energy research and technology development agency, CanmetENERGY, also falls under the aegis of NRCan and is part of the Energy Technology and Programs sector.

NATIONAL ENERGY BOARD

The National Energy Board (NEB) is an independent federal agency established in 1959 by the Parliament of Canada. It regulates the international and interprovincial features of the oil, gas and electric utility industries.

The NEB regulates interprovincial and international oil and gas pipelines, as well as the construction and operation of international power lines and certain designated interprovincial lines deemed to fall under federal jurisdiction. The NEB plays a role in health and safety standards and is engaged in environmental protection, ensuring that environmental issues are managed during the planning, construction, operation and abandonment of energy projects within its jurisdiction.

ENVIRONMENT CANADA

Environment Canada is the lead department for the government's Clean Air Agenda and is responsible for the direct regulation of green house gas (GHG) and air pollutant emissions (*e.g.* from industrial and transportation sources). Environment Canada's mandate also includes the preservation and enhancement of the quality of the natural environment; conservation of Canada's renewable resources; conservation and protection of Canada's water resources; forecasting weather and environmental change; enforcement of rules relating to boundary waters; and co-ordinating environmental policies and programmes for the federal government.

CANADIAN NUCLEAR SAFETY COMMISSION

The Canadian Nuclear Safety Commission (CNSC) was established in 2000 under the Nuclear Safety and Control Act and reports to Parliament through the Minister of Natural Resources. CNSC was created to replace the former Atomic Energy Control Board (AECB), which was founded in 1946. It is the nuclear energy and materials watchdog in Canada. The CNSC regulates nuclear power plants, nuclear research facilities and the numerous other uses of nuclear material such as uranium mines and mills for fuel and radioisotopes for pharmaceuticals. The CNSC is almost exclusively concerned with safety standards in the nuclear industry and rarely addresses market issues or environmental concerns beyond public safety needs.

COUNCIL OF ENERGY MINISTERS

The Council of Energy Ministers (CEM) is a forum for Canadian energy ministers, from the federal government, provinces and territories, to assemble and discuss the challenges and opportunities that face the energy sector. On environmental matters, work with provinces and territories is conducted by means of the Canadian Council for Ministers of the Environment (CCME), which comprises the federal Environment Minister and the thirteen provincial and territorial Environment Ministers.

NATIONAL ROUND TABLE ON THE ENVIRONMENT AND ECONOMY

The National Round Table on the Environment and Economy (NRTEE) was created by the federal government in October 1988. Its independent role and mandate were established by the National Round Table on the Environment and Economy Act. In the second half of 2006, the federal government asked the NRTEE to examine matters related to national long-term climate change and air pollution policies. Specifically, the NRTEE was asked to provide advice on how Canada could significantly reduce its GHG and air pollutant emissions by 2050.

MAJOR PROJECTS MANAGEMENT OFFICE

The Major Projects Management Office (MPMO) was established by the federal government to facilitate improvements to the regulatory process of major resource projects. Its role is to provide overarching project management and accountability for major resource projects in the federal regulatory review process, and to facilitate improvements to the regulatory system for major resource projects.

CANADA-NOVA SCOTIA OFFSHORE PETROLEUM BOARD

The Canada-Nova Scotia Offshore Petroleum Board (C-NSOPB) is an independent joint agency of the governments of Canada and Nova Scotia. It is responsible for the regulation of petroleum activities offshore Nova Scotia. It was established in 1990 pursuant to the Canada-Nova Scotia Offshore Petroleum Accord Implementation Acts (Accord Acts). The board reports to the federal Minister of Natural Resources Canada and to the provincial Minister of Energy in Halifax, Nova Scotia.

CANADA-NEWFOUNDLAND AND LABRADOR OFFSHORE PETROLEUM BOARD

The Canada-Newfoundland and Labrador Offshore Petroleum Board (C-NLOPB) was created in 1985 by means of the Atlantic Accord for the purposes of regulating the oil and gas industry offshore Newfoundland and Labrador. It is also an independent joint agency of the governments of Canada and Newfoundland. The mandate of the C-NLOPB is to interpret and apply the provisions of the Atlantic Accord and the Atlantic Accord Implementation Acts to all activities of operators in the Newfoundland and Labrador Offshore Area and to oversee operator compliance with those statutory provisions.

INDIAN AND NORTHERN AFFAIRS CANADA

Indian and Northern Affairs Canada (INAC) is the agency responsible for the management of oil and gas resources in the Northwest Territories and Nunavut. Under a process of devolution, the Yukon Territory now has similar jurisdiction to all provinces in the federation regulating management of onshore resources. Negotiations are currently under way to devolve responsibility for energy matters to the Northwest Territories.

THE PROVINCES AND TERRITORIES

Energy administration takes place both federally and provincially. The Canadian Constitution provides that legislative authority, which has an influence on energy use, is divided between provincial and federal levels of government, both geographically and functionally.

Several driving forces shape energy policy at the provincial and territorial levels:

- Provinces and territories have significantly different primary resource endowments.
- Provinces are owners of their ground resources (apart from resources located in aboriginal lands and some small pockets of federal land) and have primary responsibilities in shaping policies implemented in their jurisdictions.
- Energy plays a large role in the creation of wealth for some provinces and territories (*e.g.* Alberta, Québec, Saskatchewan, Nova Scotia and Newfoundland and Labrador).
- For most provinces, the share of external energy trade they carry out with bordering American states is often larger than with Canadian neighbouring provinces and territories.

Table 1

Provincial and Federal Resources Administration

Provincial governments	*Federal government*
• Development and management of resources within provincial boundaries. • Property and civil rights within the province, *i.e.* environmental, health, safety, land use, consumer protection, etc. • Regulation and legislative framework for electricity and natural gas, including in many cases ownership of Crown corporations engaged in these activities. • Securing appropriate economic rent as resource owner from Crown mineral rights and hydraulic forces. • Policies in the provincial interests, such as economic development, and energy science and technology. • Intraprovincial trade	• Resource management on non-Accord Frontier Lands*. • Uranium/nuclear power. • Interprovincial/international trade and commerce. • Interprovincial works and undertakings. • Trans-boundary environmental impacts. • Policies in the national interest (economic development, energy security, federal energy R&D).

* Canada's frontier lands are those lands over which the government of Canada has the right to dispose of or exploit mineral resources, including oil and gas. Frontier lands include all of Canada's offshore areas not within a province, the Northwest Territories, Nunavut and Sable Island, and cover an area of approximately 10.2 million square kilometres.

Electricity is almost exclusively regulated by the provincial and territorial governments, except international electricity lines that transport power from Canada to the United States and certain designated interprovincial power lines (representing less than 1% of the total high-voltage transmission lines in Canada). Each province has a separate sectoral regulator. Provincial regulators in some cases operate at arms-length from the federal government but are in other cases part of the policy arms of their respective government.

ENERGY POLICY

Canadian energy policy relies on competitive markets for determining supply, demand, prices and trade, and is guided by a drive for cleaner energy, in both production and use of energy across the country. The three key underlying principles of Canadian energy policy are:

- *Market orientation:* Markets are the most efficient means of determining supply, demand, prices and trade while ensuring an efficient, competitive and innovative energy system that is responsive to Canada's energy needs.

- *Respect for jurisdictional authority and the role of the provinces:* Provincial governments are the direct managers of most of Canada's resources and have responsibility for resource management within their borders.
- Where necessary, *targeted intervention in the market process to achieve specific policy objectives* through regulation or other means: These policy objectives include issues of health and safety (*e.g.* pipeline regulation) and environmental sustainability.

The government of Canada seeks to achieve a balance between the environmentally responsible production and use of energy, the growth and competitiveness of the Canadian economy, secure and competitively priced energy, and the protection of infrastructure. Canada is an energy-intensive nation, but current energy policy focuses on developing clean energy technologies and increasing energy efficiency with the adoption of advanced energy-efficient technologies and practices. Canada's energy policy has been framed by a number of agreements and accords, including the Western Accord, the Agreement on Natural Gas Markets and Prices, the Atlantic Accords and the North American Free Trade Agreement (NAFTA, which was preceded by the Canada-US Free Trade Agreement). NAFTA is a cornerstone of Canadian energy policy with regard to trade with the United States. It emphasises the importance of competitive market behaviour and encourages investment in Canadian energy markets.

Over time, numerous federal decisions have also contributed to Canada's energy policy, including the establishment of the National Energy Board, the Canadian Nuclear Safety Commission and Atomic Energy of Canada Limited.

Previously, the federal government committed to reducing Canada's total greenhouse gas emissions by 20% below 2006 levels by 2020 and by 60% to 70% by 2050. It has also committed to a goal of having 90% of Canada's electricity provided by non-carbon emitting sources by 2020. In April 2007, the federal government developed an aggressive strategy document, *Turning the Corner*, to tackle climate change.[5] A number of factors, such as the global economic downturn and change of government in the United States, have led the federal government to review its current approach to climate change.

On 30 January 2010, Canada announced the submission of its 2020 emissions reduction target under the Copenhagen Accord. Canada's 2020 target, an economy-wide 17% reduction from 2005 levels, is aligned with the United States target, and is subject to adjustment to remain consistent with the U.S. target. Canada continues to support the G8 partners' goal of reducing global emissions by at least 50% by 2050, as well as the goal of developed

5. *Turning the Corner: Regulatory Framework for Industrial Greenhouse Gas Emissions*, Environment Canada, 2007

countries reducing emissions of greenhouse gases in aggregate by 80% or more by 2050.

The government of Canada supports an approach to climate change that achieves real environmental and economic benefits for all Canadians. Furthermore, Canada has indicated that it will work actively with its international partners to implement the Copenhagen Accord as the basis for a new, legally binding post-2012 climate change agreement.

The federal government's economic response to the global economic downturn, Canada's Economic Action Plan, includes more than CAD 2 billion[6] of investments in programmes designed to protect the environment, stimulate the economy and transform energy technologies. The government has also committed CAD 1 billion over five years for clean energy research and demonstration projects, including CAD 650 million for large-scale carbon capture and storage (CCS) projects, and CAD 1 billion for a Green Infrastructure Fund that will support modern development of energy transmission lines and sustainable energy projects.[6] Canada is taking a leadership role in the development of new, clean technologies by helping found the Global Carbon Capture and Storage Institute, a new global partnership to advance CCS technologies.

MARKET REFORM

Electricity markets fall under the aegis of the provincial governments and the structure of electricity market varies from province to province. Currently, none of the provinces have announced plans to enact major changes to their electricity power sector (in terms of regulatory structure). The province of New Brunswick announced a review of the structure of the province's electricity market in 2008.

From a petroleum exploration and production perspective, the possibility of opening some areas now closed for exploration and production is not a concern at present. In the case of George's Bank (offshore Nova Scotia), the federal Minister of Natural Resources and his/her provincial counterpart must decide in 2010 whether to conduct a public review of the moratorium. Following the review, the two governments would consider the results and take a decision. As it stands now, the moratorium is in effect until 31 December 2012.

In relation to transportation of oil and natural gas, the National Energy Board (NEB) has streamlined the application process for small, interprovincial pipelines in 2008. The streamlined process is online, and automated to assess each project on the basis of transparent risk criteria.

6. On average in 2009, CAD 1 = USD 0.876.

Oil

Canada is a significant net exporter of oil. Nonetheless, the country is not immune to the risks of a supply disruption. Despite increases in nearby offshore production, refiners in the country's eastern provinces rely on imported crude oil. Some central provinces have also experienced oil product disruptions in recent years, due to their relative geographic isolation from alternative sources of supply. Moreover, with an extensive system of pipelines moving large volumes of oil from the west towards domestic and United States markets across the continent, a significant disruption to any of these pipelines could pose a serious challenge to emergency response for refined oil products. The Emergency Supplies Allocation Board (ESAB) has the authority to regulate building, storage and disposal of stocks, including industry stocks, during a declared national emergency (see Chapter 9 on Oil). The federal government has stated that it is currently studying the possibility of creating a Strategic Petroleum Reserve.

Natural Gas

Canada is a net gas exporter, as well as the main supplier of natural gas to the United States. The natural gas market in Canada is resource-rich, efficient, competitive and diversified, and the present structure of the natural gas market provides a high degree of energy security. In the case of a disruption, the federal government has considerable powers to control natural gas flows in the event of a national emergency under the Emergencies Act. If a national emergency is not declared, however, natural gas flows fall under provincial jurisdiction. Generally, in Canada, the risk is not a disruption in supplies, but rather that prices may be higher than expected. There are no government-imposed requirements for any market participant to hold a minimum level of stocks.

Electricity

Canada and the United States share a highly integrated electricity transmission network. In general, responsibility for regulatory oversight of the electricity supply industry rests with the provincial governments and their respective regulatory agencies. The federal government considers reliability issues when developing electricity policy and regulations for interprovincial and international trade. For interconnected bulk power systems, the North American Electric Reliability Council (NERC) and its regional councils, of which most Canadian electric utilities/system operators are members, have assumed the main responsibilities for setting reliability standards and operating policies. Membership in NERC is voluntary, with standards and policies compliance enforced mainly through peer pressure. (Most provinces have legislation or contractual arrangements with NERC that effectively make NERC standards mandatory in their jurisdiction. The regulation of NERC standards remains with the province or territory.)

Critical infrastructure and emergency management

Canada has also strengthened policies to protect critical energy infrastructure, through its National Strategy for Critical Infrastructure Protection and supporting Action Plan. The purpose of the strategy is to strengthen the resiliency of critical infrastructure, including energy infrastructure, in Canada against current and emerging hazards. This will be achieved through building trusted and sustainable partnerships, implementing an all-hazards risk management approach, and advancing the timely sharing and protection of information among partners.

Canada has also updated and amended the Emergency Management Act with the aim to strengthen the government's readiness to respond to all types of major emergencies and set a clear direction for emergency management and critical infrastructure protection. Canada is also working to strengthen North American energy collaboration through the Security and Prosperity Partnership, which includes protection of critical infrastructure.

ENERGY PRICES AND TAXES

PRICES AND SUBSIDIES

There are minimal energy commodity price controls in Canada. Unleaded gasoline prices, including taxes, are among the lowest in the OECD. Nonetheless, some price controls remain in place in Newfoundland and Labrador, Nova Scotia, New Brunswick, Prince Edward Island and Québec. The IEA does not collect data in relation to natural gas or electricity prices in Canada but they are published by NRCan and details may be found on their website.[7]

Canadian electricity consumers are understood to benefit from some of the lowest electricity prices in North America. Electricity prices are regulated in most provinces on a cost-of-service basis, reflecting the costs of generation, transmission and distribution. These costs and, therefore, electricity prices vary from province to province. The lowest electricity prices are found in the hydro-dominant provinces of British Columbia, Manitoba and Québec. While electricity prices in other provinces are higher, they are still low when compared to many IEA member countries.

TAXES

Tax treatment of the oil and gas sectors in Canada has been undergoing fundamental reforms. Royalties are now fully deductible, and the resource allowance, a special deduction permitted in lieu of royalty deductibility, has been phased out. Also, corporate tax rates for the oil and gas sectors, which

7. http://nrcan.gc.ca/eneene/sources/natnat/hishis-eng.php (last accessed 31 December 2009).

had been higher than those for other industries, have been brought into line with the general corporate rate. Finally, the accelerated capital cost allowance (CCA) for oil-sands mining and *in situ* projects (which permitted companies a fast write-off of certain kinds of assets) will be phased out, as announced in Budget 2007.

In Budget 2009, the Canadian government announced that it would consult with stakeholders to identify specific assets used in carbon capture and storage with a view to providing accelerated CCA in respect of such investments. A deferment of taxation would provide an incentive to invest in this clean energy technology.

Federal excise taxes are imposed on leaded and unleaded gasoline and aviation gasoline, as well as on diesel and aviation fuels.

Since April 2008, renewable fuels are subject to federal excise taxation as motive fuels in accordance with the definitions of gasoline and diesel fuel. This means, for example, that the alcohol portion of gasoline-alcohol blends and biodiesel or the biodiesel portion of diesel-biodiesel blends are subject to federal excise tax at the applicable rate for gasoline or diesel fuel, respectively. Current excise tax rates are set out in Table 2.

Table 2

Excise Tax Rates 2009

CAD 0.10 per litre	Unleaded gasoline and unleaded aviation gasoline
CAD 0.11 per litre	Leaded gasoline and leaded aviation gasoline
CAD 0.04 per litre	Diesel fuel and aviation fuel (other than aviation gasoline)

Source: NRCan.

Diesel fuel that is used as heating oil is exempt. Diesel fuel that is used in the generation of electricity is also exempt, except where the electricity so generated is used primarily in the operation of a vehicle.

There are two main tax measures to support investments in the production of electricity from renewable sources. First, under the Federal Income Tax Act, equipment that is designed to produce energy from renewable sources is eligible for an accelerated capital cost allowance at 50% on a declining basis. Secondly, for projects using these renewable energy technologies, many start-up expenses qualify as Canadian Renewable and Conservation Expenses (CRCE) that may be deducted in full in the year incurred, carried forward indefinitely for deduction in later years or transferred to investors using flow-through shares.

Canada has provided support to northern communities to assist with pressures caused by remote and seasonal issues, including access to energy supply. Support has been provided to First Nations communities in northern Ontario to upgrade infrastructure for power generation and alleviate the impact of high diesel fuel costs on generating and distributing electricity.

CRITIQUE

Canada is one of the largest energy producers in the OECD and its largest exporter of energy.[8] Energy accounted for 6.8% of GDP, 24% of investment and 27% of export earnings in 2008. The importance of the energy sector for the Canadian economy has grown steadily over the last decade and its abundant and diverse resource base has the potential to deliver even greater volumes of energy.

The Canadian government fully understands the role its energy sector plays in the greater economy and its potential contribution to meeting global energy demand and security. Witness to this are several government actions, such as: implicit support of the commendable provincial resources management policies (and its direct, partly shared, resource management in the offshore and North); the government's active participation in numerous international energy partnerships and initiatives; and the recognition that its rich fossil resources endowment entails a particular effort to contributing to the cleaner use of fossil energy, especially by reducing the environmental impact of oil-sands and deploying carbon capture and storage (CCS). Indeed, large-scale deployment of CCS is one of the key components of Canada's long-term energy future. The government is to be lauded for this position.

A sizeable portion of energy supply growth in recent years, particularly in the oil and gas sectors, is attributable to foreign investment as a consequence of the 1990 government decision to open investment in the upstream oil and gas sectors to non-Canadian firms. The government is to be commended for contributing – jointly with the provincial governments – to shaping a favourable investment framework. This framework has demonstrated its ability to change and evolve as circumstances demand; for example, by amending royalty regimes in response to change in the global investment climate.

The federal government's overall energy policy is guided by the primacy of free-market principles and regard for the jurisdictional authority of the provinces. The Constitution provides that the government may use targeted intervention in the marketplace to achieve specific policy objectives, for example in relation to environmental sustainability. The existence of multiple authorities

8. *Energy Balances of OECD Countries*, IEA/OECD Paris, 2009.

at differing levels of government, however, has led to increased complexity and sometimes unnecessary delay for industry in obtaining relevant project development approvals.

In response, the Major Projects Management Office (MPMO) has been established, which aims to provide industry with overarching management and accountability for streamlining major resource projects within the federal regulatory review process. The government is to be commended for this notable initiative. It could go further, and establish a firmer legislative mandate for the MPMO. The potential investments that would occur as a result of streamlined regulatory approval could be significant.

The introduction of the Northern Regulatory Improvement Initiative (NRII) by Indian and Northern Affairs Canada (INAC) is another positive step towards improving regulatory processes in the North, mainly focused on the Northwest Territories and Nunavut. The federal government should build on the recommendations contained in this report and increase its focus on improving the regulatory regimes in the North, for example by simplifying regulatory processes and reduce the number of regulatory bodies involved.

The establishment of federal bodies, regulations and programmes attests to the evolutionary nature of the division of jurisdictional authority between the federal government and the provinces. While the Canadian Constitution confers extensive rights to the provinces with regard to energy resources and systems, the federal government may have to decidedly clarify certain interfaces between federal and provincial energy policies in the light of current global energy and especially climate developments. The federal government is responsible for promoting the overall economic development of Canada, but must do so by working in partnership with provinces and territories. Overlaps and possibly gaps between provincial and federal policies may need to be addressed through greater policy co-ordination; efforts to develop such policies are progressing. In this regard, both the Council of Energy Ministers (CEM) and the Canadian Council for Ministers of the Environment (CCME) are good examples of the potential role of the federal government in co-ordinating federal-provincial-territorial communication on matters relating to national energy and climate change.

The Council of Energy Ministers is a forum for Canadian energy ministers from the government of Canada, provinces and territories, to assemble and discuss the challenges and opportunities that face the energy sector. On environmental matters, work with provinces and territories is conducted by means of the Canadian Council for Ministers of the Environment (CCME), which comprises the federal Environment Minister and the thirteen provincial and territorial Environment Ministers. These councils provide the federal government with a platform to constructively engage with provincial and territorial governments and to offer a regular opportunity to discuss greater levels of intergovernmental co-ordination.

The federal government has clearly stated its commitment to avoiding duplication of regulatory measures and its interest in entering into equivalency agreements with interested provinces, as long as those provinces set enforceable provincial emission standards that are at least as stringent as the federal standards. Should it subsequently be determined that the two regimes are equivalent, and subject to an assessment of legal and policy risks, a formal equivalency agreement could be concluded.

The Canadian Environmental Protection Act, 1999 provides that the Minister of the Environment can enter into an equivalency agreement with a provincial, territorial or aboriginal government. An equivalency agreement may cover all provisions or only specified provisions, as deemed appropriate. In particular, the agreement could just focus on certain sectors. Under such an agreement, the minister can recommend that some or all of the provisions of the federal regulations do not apply in an area that is under the jurisdiction of that other government.

A number of provinces are implementing noteworthy and progressive energy policies. Notable examples include Ontario's feed-in tariffs for renewable electricity, British Columbia and Québec's carbon taxes, Alberta's CAD 2 billion CCS Fund and Prince Edward Island's renewable targets and strengthened integration with its neighbouring provinces. One of the goals of the CEM and CCME has been to promote best practices, although both are now moving towards outcome-oriented activities. The federal government could take a more proactive role in encouraging provinces to emulate best practices and policies that have been successfully adopted elsewhere.

Federal-provincial-territorial government co-operation is particularly imperative in the field of climate policy for several reasons; emissions targets are binding under international law (*i.e.* the Kyoto Protocol, which Canada has ratified) and are likely to continue to be so under a post-Kyoto regime. The government will need to ensure that federal and provincial policies will deliver emissions reductions commensurate with the binding targets it has entered or will enter into under international law.

The federal government, however, has for the moment placed its climate policies (*Turning the Corner*) under review. In many sectors, in particular in the unconventional oil and natural gas industries, uncertainty as to future regulation is becoming a major barrier to investment. The federal government urgently needs to address these concerns to regain the initiative, both nationally and internationally, in matters related to climate change. This will require careful negotiation with provincial and territorial governments. Furthermore, while the federal government's intention to link its climate policy with the emerging cap-and-trade system in the United States is both understandable and commendable, Canada should remain vigilant and not lose its climate policy initiative.

Given the competitiveness impacts of climate policies, the government could play a role which is not dissimilar to its role in general economic and fiscal policies. It should contribute to fostering the economic efficiency of climate policies by creating the largest possible carbon market. In this regard, the October 2009 announcement of a Clean Energy Dialogue Report and Action Plan by the governments of Canada and the United States is welcome. The plan identifies specific initiatives the United States and Canada have agreed to undertake as areas for enhanced co-operation. With respect to climate change, they reaffirmed their commitment to co-operate closely as they develop their respective approaches.

Recent moves by the federal government to promote energy efficiency and renewable energy through the introduction and tightening of efficiency standards and programme launches are commendable. The alignment of regulation with United States regulation is understandable given the close economic ties but, in many instances, Canada should, at least in the medium term, strive to meet efficiency levels which are comparable to best international practices. At present, Canada uses performance-based standards, not prescriptive standards as found in many other OECD member countries. The level of regulation and the often limited duration of present initiatives often do not provide investor confidence. Total federal government spending on sustainable energy programmes, in terms of costs and revenues (*e.g.* accelerated capital cost allowances), is commendable but insufficient to encourage the necessary large-scale investment in world-class energy efficiency programmes or low-carbon facilities.

RECOMMENDATIONS

The government of Canada should:

- *Take a leadership role, by working with the relevant provincial and territorial governments to achieve a clear Canadian climate change policy including the implementation of a Canadian carbon capture and storage strategy.*
- *Continue steps to provide clearer delineation of federal and provincial authority over sectoral regulatory policies and use existing forums and mechanisms to facilitate co-ordination between the provinces and within the territories.*
- *Develop, with the provinces and territories, codes and regulations for higher energy efficiency standards with a specific focus on the road transport sector and the buildings sector.*

OVERVIEW

The Kyoto Protocol was signed by Canada in April 1998, and formally ratified by the government of Canada in December 2002. In February 2005, a number of countries, representing a sufficient percentage of 1990 greenhouse gas emissions, had ratified the Kyoto Protocol for it to enter into force. Canada committed to reduce greenhouse gas (GHG) emissions to 6% below 1990 levels during the commitment period 2008-2012. Canada's total base year (1990) greenhouse gas emissions were 592 million tonnes of CO_2-equivalent. According to the most recent GHG inventory report, total GHG emissions in Canada in 2007 were 747 Mt CO_2-eq.

In 2007, the government of Canada committed to reduce its greenhouse gas emissions to 20% below 2006 levels by 2020 and to 60%-70% below 2006 levels by 2050. Canada has also committed to ensuring that 90% of Canada's electricity needs are provided by non-emitting sources such as hydro, nuclear, clean coal or wind power by 2020.

Canada published a climate change policy document, *Turning the Corner*, in 2007. However, given the level of integration of the North American economy, the federal government believes that it would be prudent to work to harmonise and align a range of principles, policies, regulations and standards with the United States. The federal government is examining its approach to climate change in light of the re-engagement of the United States in the effort to combat climate change.

The government of Canada has committed to work with the provincial and territorial governments and its partners to develop and implement a North American-wide cap-and-trade system for greenhouse gases. In addition, Canada is working with the United States towards a single North American standard for greenhouse gas emissions and fuel economy from passenger vehicles. Canada has published a *Notice of Intent* to regulate greenhouse gas emissions from new cars and light-duty trucks, under the Canadian Environmental Protection Act (CEPA) to take effect with the 2011 model year.

In early 2010, Canada announced the submission of its 2020 emissions reduction target under the Copenhagen Accord. Canada's 2020 target, an economy-wide 17% emissions reduction below 2005 levels, is aligned with the United States target, and will be subject to adjustment to remain consistent with the United States target. Canada will continue to support the G8 partners' goal of reducing global emissions by at least 50% by 2050, as well as the goal of developed countries reducing emissions of greenhouse gases in aggregate by 80% or more by 2050.

Furthermore, Canada has indicated that it will work actively with its international partners to implement the Copenhagen Accord as the basis for a new, legally binding post-2012 climate change agreement.

In June 2009, the government published new guidelines for Canada's Offset System for Greenhouse Gases. The domestic Offset System is an important step in the creation of a carbon market in Canada, establishing tradable credits for GHG reductions and encouraging cost-effective domestic emissions reductions in areas that will not be covered by planned federal regulations (*e.g.* forestry and agriculture). The Offset System is designed to reduce greenhouse gas emissions and generate real emissions reduction opportunities across the economy. Offset projects will achieve real, incremental, verifiable reductions in greenhouse gas emissions.

The government has also invested in a series of ecoACTION programmes intended to promote the development and deployment of new technologies to improve energy efficiency and reduce greenhouse gas emissions. These initiatives are oriented to a wide range of sectors, including transport, agriculture, construction and energy. Collectively, they promote the use of biofuels, renewable power and a variety of energy-efficient technologies.

The CEPA is the legislative authority for Environment Canada to establish the national inventory system and to designate Environment Canada's Greenhouse Gas Division as the single national entity with responsibility for the preparation and submission of the national inventory to the United Nations Framework Convention on Climate Change (UNFCCC). Provinces and territories are also actively pursuing climate change initiatives.

DOMESTIC EMISSIONS PROFILE

While Canada contributes only about 2% of total global GHG emissions, it is one of the highest per-capita emitters, largely the result of its size, climate (energy demands), and resource-based economy. Canada's CO_2 emissions-intensity, when measured against GDP using purchasing power parities, is among the highest in the OECD, the second-highest after Australia. Total GHG emissions in 2007 were 747 Mt CO_2-eq, an increase of 4% over 2006 levels, and 0.8% higher than 2004 levels. Notably, emissions from mining and oil and gas extraction alone increased by 56.7% between 2004 and 2007 owing to increased activity in the Albertan oil-sands. However, these emissions represent less that 4% of total Canadian GHG emissions in 2007.

Overall, the long-term trend indicates that emissions in 2007 were about 26% above the 1990 total of 592 Mt CO_2-eq. This trend shows a level 33.8% above

Canada's target of 557 Mt CO_2-eq[9] under the first commitment period of the Kyoto Protocol. CO_2 is the largest contributor to Canada's GHG emissions.

In 2007, the highest contribution to Canada's CO_2 emissions came from oil and natural gas while the largest emitting sector is transportation (200 Mt CO_2-eq or 27%) followed by electricity and heat generation (126 Mt CO_2-eq or 17%). CO_2 emissions from the transport sector have increased by 37.5% since 1990 while emissions from the electricity sector have increased by 32%. With the exception of the Industrial processes and land-use/land-use change and forestry (LULUCF) sectors, CO_2 emissions across all sectors and fuels have increased since 1990.

Canada's GHG emissions vary from province to province, largely owing to the distribution of natural resources, population and industry within the country. For example, oil and gas development is a substantial basis of Alberta's and increasingly Saskatchewan's economy. Ontario is industrial (manufacturing centre) while British Columbia and Québec have significant hydro resources. Ontario, Québec and British Columbia are the most populous provinces while the North (the Yukon, Northwest Territories and Nunavut) is a large but sparsely populated region. The highest emitting provinces are Alberta, Ontario, Québec, Saskatchewan and British Columbia. Alberta and Ontario reported the highest emission levels, accounting for 33% (234 Mt) and 27% (190 Mt) of national emissions, respectively, in 2006. While GHG emissions per unit of economic activity have fallen from 1990 to 2006, total emissions for most provinces increased over the same period. Québec, Nova Scotia, and Newfoundland and Labrador produced minimal change (less than 5%) while the territories showed moderate decreases in emissions over this period.[10]

In March 2004, the government of Canada established the Greenhouse Gas Emissions Reporting Program under section 46(1) of CEPA 1999. The programme specifically targets large-scale industrial GHG emitters in Canada, those that emit 100 kt CO_2-eq or more annually. Voluntary submissions from facilities with GHG emissions below the reporting threshold are also encouraged. The federal programme became law in 2005 and required reporting for 2004. Alberta's mandatory reporting programme (same threshold) became law in 2004 and required reporting for 2003. In 2006, a total of 343 facilities reported emissions accounting for 273 Mt of GHGs. The majority of reported emissions are CO_2, at approximately 94% of emissions. Methane (CH_4) accounted for 3%, nitrous oxide (N_2O) represented around 2% and hydrofluorocarbons (HFCs), perfluorocarbons (PFCs) and sulphur hexafluoride (SF_6) combined accounted for the remaining 1%. Reported facility emissions represent just over one-third (~38%) of Canada's total emissions.

9. *Information on Greenhouse Gas Sources and Sinks, Canada's 2007 Greenhouse Gas Inventory – A Summary of Trends*, Environment Canada, 2007.
10. *The National Inventory Report 1990–2006: Greenhouse Gas Sources and Sinks in Canada*, Environment Canada, 2008.

Table 3

Facility-Reported GHG Emissions by Gas, 2006

GHG	*Total emissions (kt CO_2-eq)*	*Percentage of total*
Carbon dioxide, CO_2	256 306	94
Methane, CH_4	8 521	3
Nitrous oxide, N_2O	4 418	2
Hydrofluorocarbons, HFCs	41	0.02
Perfluorocarbons, PFCs	2 626	1
Sulphur hexafluoride, SF_6	1 246	0.5
Total	**273 158**	**100**

Source: *The National Inventory Report 1990–2006: Greenhouse Gas Sources and Sinks in Canada*, Environment Canada, 2008.

Table 4

Facility-Reported GHG Emissions by Province/Territory, 2006

Province/territory	*Number of reporting facilities*	*Total reported emissions (kt CO_2-eq)*	*Percentage of total*
Alberta	103	115 421	42
Ontario	86	71 709	26
Québec	52	22 307	8
Saskatchewan	23	22 522	8
British Columbia	38	12 316	5
New Brunswick	14	10 191	4
Nova Scotia	8	10 880	4
Newfoundland and Labrador	8	4 953	2
Manitoba	8	2 438	1
Northwest Territories	2	319	0
Prince Edward Island	1	100	0
Nunavut	NA	0	0
Yukon	NA	0	0
Total	**343**	**273 156**	**100**

Source: *The National Inventory Report 1990–2006: Greenhouse Gas Sources and Sinks in Canada*, Environment Canada, 2008.

EMISSIONS OUTLOOK

In 2006, Natural Resources Canada released *Canada's Energy Outlook: The Reference Case 2006*.[11] Energy-related emissions were projected to increase by almost 1.1% per year during the projection period to 2020. A much higher emissions profile was projected over the period to 2010 driven by a large increase in emissions from the upstream and refining sectors. In March 2008, Environment Canada released an updated baseline to incorporate the revised estimation methodology and the most recent available information on economic growth as well as energy demand and supply into the future.[12] This report found that emissions in 2006 were 22% higher than in 1990 and that they peaked in 2004 at 743 Mt CO_2-eq and then declined by 3% from 2004 to 2006.

More recent emissions data suggest that between 1990 and 2007, the net increase in Canada's annual greenhouse gas emissions totalled about 155 Mt CO_2-eq. Over the same period, emissions from the energy industries (fossil fuel production and electric power) and transportation increased by about 139 Mt CO_2-eq, accounting for most of the overall increase.

At present, Canada is in the process of updating its emissions forecast for 2020 to reflect most recent data as well as policy developments at the federal and provincial levels.

Table 5

Greenhouse Gas Emissions in Canada, 2006 to 2020

	2006	*2010*	*2015*	*2020*
	Mt CO_2	*Mt CO_2*	*Mt CO_2*	*Mt CO_2*
Residential	39.8	43.9	48.3	51.9
Commercial	37.7	43.1	51.1	58.4
Transportation	162.4	170.8	197.7	217.3
Industrial: non-regulated	41.6	42.8	47.9	52.4
Industrial: regulated	343.6	370.7	389	396.9
Agriculture, wastes and others	96.0	100.9	112.1	123.1
Total	**721.1**	**772.3**	**846.1**	**900.0**

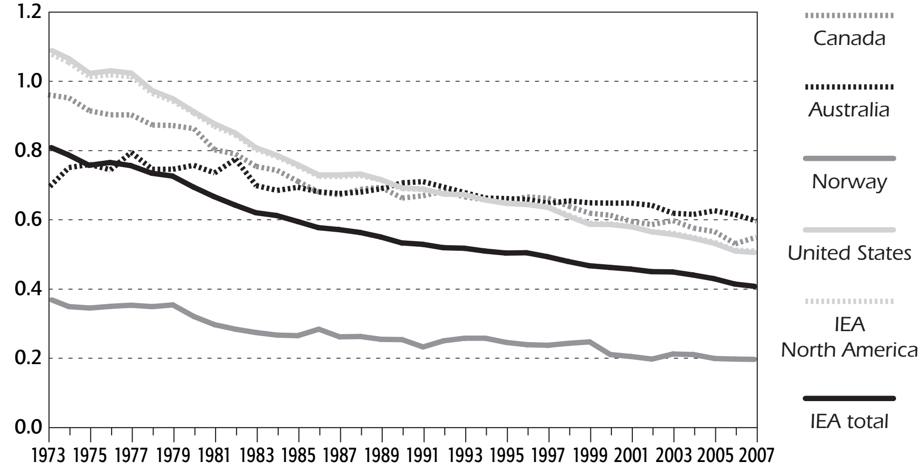
Source: Environment Canada.

11. *Canada's Energy Outlook: the Reference Case 2006*, Environment Canada, 2006.
12. *Canadian Environmental Sustainability Indicators 2008*, Environment Canada, 2008.

Figure 5

Energy-Related CO_2 Emissions per GDP in Canada and in Other Selected IEA Member Countries, 1973 to 2007

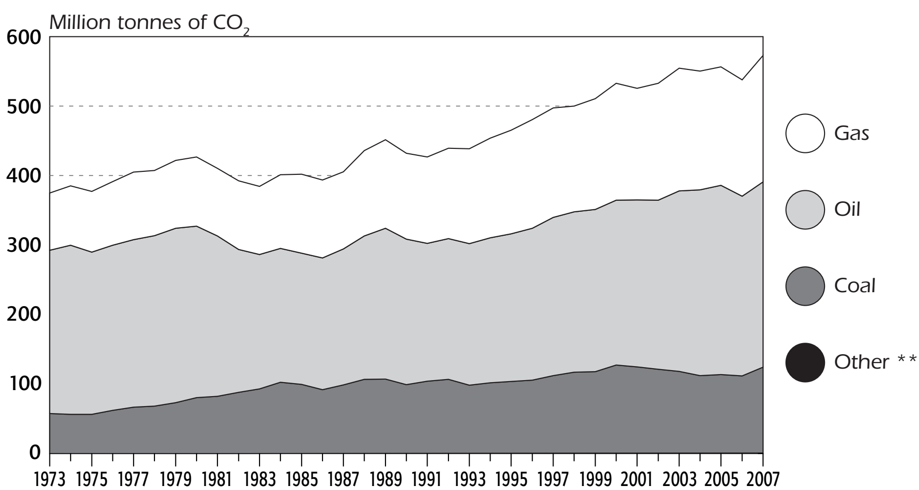
(tonnes of CO_2 emissions per thousand USD/GDP using 2000 prices and purchasing power parities)



Sources: *Energy Balances of OECD Countries, IEA/OECD Paris, 2009 and National Accounts of OECD Countries*, OECD Paris, 2009.

Figure 6

CO_2 Emissions by Fuel*, 1973 to 2007



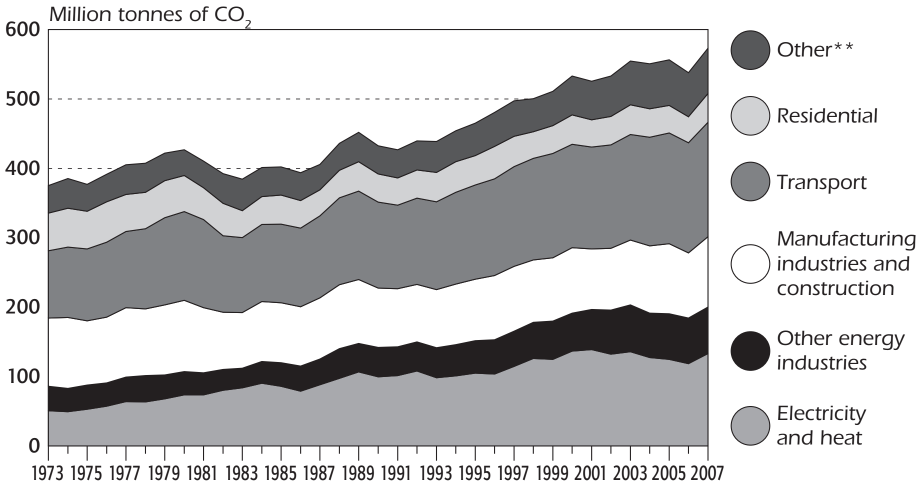
* estimated using the IPCC Sectoral Approach.

** includes industrial waste and non-renewable municipal waste (negligible).

Source: *CO_2 Emissions from Fuel Combustion*, IEA/OECD Paris, 2009.

Figure 7

CO_2 Emissions by Sector*, 1973 to 2007



* estimated using the IPCC Sectoral Approach.

** includes emissions from commercial and public services, agriculture, forestry and fishing.

Source: *CO_2 Emissions from Fuel Combustion*, IEA/OECD Paris, 2009.

INSTITUTIONS

ENVIRONMENT CANADA (EC) – EC is the lead department with responsibility for the delivery of the government's Clean Air Agenda. As such, EC is responsible for the development and implementation of the industrial GHG regulations and a number of complementary programme measures to address those areas that are not effectively covered by the regulatory framework. In addition, EC is the main department for the development of Canadian positions on international climate change and leads Canadian delegations to international climate change discussions and negotiations.

NATURAL RESOURCES CANADA (NRCan) – NRCan seeks to enhance the responsible development and use of Canada's natural resources and the competitiveness of Canada's natural resources products. NRCan sets energy policy and administers many of the federal ecoENERGY, clean energy supply, and energy demand reduction programmes, as well as provides expertise on climate change impacts and adaptation and on clean energy technology. The Canadian Forest Service within NRCan provides climate change mitigation expertise in the forestry sector. NRCan is also involved in the development of policy options on international climate change, particularly on technology, land-use and deforestation. NRCan also contributes its expertise to the Asia-Pacific Partnership on Clean Development and Climate (APP) with a specific focus on energy- and technology-related matters.

TRANSPORT CANADA – Transport Canada is the lead department for Clean Transportation and contributes to the Clean Air Agenda through work towards improved management of sustainable transportation infrastructure in communities; improved efficiency and reduced emissions of air pollutants and greenhouse gases from the movement of goods; and improved fuel efficiency and reduced emissions from the personal vehicle fleet. In relation to environmental policy, Transport Canada is responsible for policy development and decision making by preparing regulations and measures, including information and financial incentives.

FOREIGN AFFAIRS AND INTERNATIONAL TRADE (DFAIT) – DFAIT contributes to the Clean Air Agenda through work in international obligations, participation and negotiations. It engages in strategic international climate change discussions and negotiations on behalf of the Canadian government and previously undertook actions related to compliance with existing treaty obligations under the United Nations Framework Convention on Climate Change and the Kyoto Protocol. Alongside Natural Resources Canada (NRCan), DFAIT works on energy-related issues bilaterally with key countries such as the United States and China, and in multilateral forums.

INDUSTRY CANADA (IC) – IC contributes to the Clean Air Agenda through its work with Environment Canada and Natural Resources Canada on the Asia-Pacific Partnership on Clean Development and Climate, which is an innovative new effort to accelerate the development and deployment of clean energy technologies. IC also analyses the economic and industrial impacts of proposed regulatory GHG reduction initiatives.

INDIAN AND NORTHERN AFFAIRS CANADA (INAC) - Indian and Northern Affairs Canada plays a role in addressing emissions in the North by providing incentives to develop renewable energy and energy efficiency projects in aboriginal and northern communities.

POLICIES

In October 2006, the federal government issued a *Notice of Intent* which proposed an integrated, nationally consistent approach to the regulation of greenhouse gas and air pollutant emissions. The federal government committed to develop and implement an integrated, nationally consistent approach to the regulation of industrial air emissions. Throughout 2006 and early 2007, extensive consultations were undertaken with the provinces and territories, industry, aboriginal groups, and health and environmental groups on elements of the proposed approach and the development of the regulatory framework.

Subsequently, in April 2007, the federal government published its long-term climate change policy document – *Turning the Corner: Regulatory Framework for Industrial Greenhouse Gas Emissions*. This policy document contained a series of very specific actions to achieve reductions of both air pollutant and GHG emissions in the short term. The federal government previously committed to reducing greenhouse gas emissions relative to 2006 levels by 20% by 2020 (equivalent to 3% below 1990 levels), and 60% to 70% by 2050. The federal government has also committed that 90% of domestic electricity would be provided by non-emitting sources by 2020 from around 78% in 2008. More recently, Canada announced the submission of its 2020 emissions reduction target under the Copenhagen Accord. Canada's 2020 target, an economy-wide 17% emissions reduction below 2005 levels, is aligned with the United States target. Canada continues to support the G8 partners' goal of reducing global emissions by at least 50% by 2050, as well as the goal of developed countries reducing emissions of greenhouse gases in aggregate by 80% or more by 2050.

TURNING THE CORNER

The policy document articulated an action plan comprising several distinct components:

- a regulatory framework for industrial emissions of greenhouse gases and air pollutants;
- the development of mandatory fuel efficiency standards for automobiles from 2011 supplemented by other actions targeted on the remaining transport sector;
- new energy efficiency performance standards for electricity-consuming products;
- the development of measures to improve indoor air quality.

The plan identified a number of measures with the potential to have a significant impact on reducing GHG emissions and other air pollutants. The plan also included a set of mandatory and enforceable measures targeted across all emitting sectors. The policy framework is in turn supported by complementary measures in the renewable energy and technology sectors as well as by a variety of initiatives in the provinces and territories.

Regulations were to be introduced to mandate reductions in GHG emissions and air pollutants from the following industrial sectors:

- electricity generation produced by combustion;
- oil and gas;
- forest products;
- smelting and refining;
- iron and steel;

- iron ore pelletising; and
- potash, cement, lime and chemicals.

For GHGs, the framework set a 2010 implementation date for emission intensity reduction targets. For air pollutants, the framework set fixed emission caps that will enter into force as soon as possible between 2012 and 2015.

In 2010, facilities existing in 2006 would have been required to reduce emissions to meet GHG emissions targets. For these facilities, the emission intensity reduction target for each sector was based on an improvement of 6% each year from 2007 to 2010. This would have yielded an initial enforceable reduction of 18% in 2010 below 2006 emission intensity levels. Every year thereafter, a 2% continuous emission intensity improvement would have been required, resulting in an industrial emission intensity reduction of 26% by 2015.

Newer facilities using cleaner fuels and technologies were to have a three-year grace period. This grace period allowed new facilities to reach full production and to establish their initial emission levels. Targets for new facilities were to be established on the basis of cleaner fuel standards. These targets would have resulted in absolute reductions in GHG emissions from industry as early as 2010 and no later than 2012.

In order to provide flexibility and minimise the economic impact of the regulations, there were a number of options available to industry to meet its obligations. These options include:

- *in-house reductions:* companies can reduce their GHG emissions through a number of abatement actions, such as energy efficiency measures, improved energy management systems, or investments in carbon capture and storage or other emissions-reducing technologies;
- *contributions to a technology fund:* technological advancement and innovation are critical to achieving deep, long-term reductions in GHG emissions. Industry was to be able to meet part of their regulatory obligations by contributing to a technology fund that would have been used to develop and deploy technologies to reduce emissions now and in the future across industries and regions;
- *emissions trading:* companies whose emissions were below their target would receive credits that could have either been "banked" for future use, or sold to other companies who had not met their target;
- *offsets:* as part of the domestic emissions trading mechanism, companies could have acquired offset credits by purchasing emissions reductions from activities that were not regulated (*e.g.* emissions from agriculture);
- *access to Kyoto's clean development mechanism (CDM):* limited to 10% of each facility's reduction target. This would generate real reductions globally through emissions reductions from projects in developing countries.

Furthermore, companies that took verified action to reduce greenhouse gas emissions between 1992 and 2006 would have been eligible to receive a one-time credit that could be applied towards their regulatory obligations or traded. *Turning the Corner* limited credits for early action to a maximum of 15 Mt CO_2-eq across industry (limited to 5 Mt in any one year).

Despite its good intentions, the implementation of *Turning the Corner* framework has stalled recently. Conscious of the global economic environment and the possible emergence of a new framework in the United States, the Canadian government is re-evaluating its approach to climate change. Given the importance of the Canada-US trading relationship (In 2008 25% of Canadian GDP was attributed to goods and services trade with the United States), an important element of this new approach is the recognition of the need to harmonise regulations between Canada and the United States A major part of this new approach will be changing to absolute emissions reduction targets as part of a cap-and-trade system, not intensity-based targets put forward in *Turning the Corner*.

SECTOR POLICIES

The federal government has a range of ecoACTION programmes, which promote the development and deployment of new technologies that improve energy efficiency and reduce greenhouse gases.

TRANSPORTATION

Transportation is one of the largest sources of GHG and air pollutant emissions, accounting for about 27% of Canada's total GHG emissions in 2007. Gasoline-powered automobiles and light trucks contribute approximately 11% of total Canadian GHG emissions. Transport-related emissions increased by 38% between 1990 and 2007.

The Canadian Environmental Protection Act (CEPA), 1999 provides authority to establish federal regulations to limit GHG emissions from motor vehicles. In April 2009, a *Notice of Intent* was published by Environment Canada; it proposed regulations to limit emissions from new cars and light-duty goods vehicles that would take effect with 2011 model-year vehicles. Accordingly, GHG emission regulations will be established that are equivalent to United States fuel economy standards that were announced in March 2009.

The federal government is also developing a series of regulations to reduce air pollutant emissions from on-road and off-road vehicles and engines.

To reduce GHG emissions from rail, the federal government and the Railway Association of Canada signed a Memorandum of Understanding (MOU) in

May 2007 establishing GHG emission intensity standards for rail services such as freight and passenger transit. Once the MOU expires, the voluntary approach will be replaced with a regulatory regime. The Minister of Transport will implement new regulations, under the Railway Safety Act, to take effect in 2011. Transport Canada is also in the process of developing regulations, under the Rail Safety Act, for the purpose of aligning with the United States Environmental Protection Agency (EPA) locomotive emission standards. These regulations will take effect from 2012. The federal government is also working with international partners to reduce emissions from marine and aviation traffic through the International Maritime Organization and the International Civil Aviation Organization (ICAO) respectively.

The federal government's ecoACTION strategy to improve energy efficiency, curb greenhouse gases and air pollutants includes a range of transport initiatives. Examples include:

- The ecoMobility Program invests CAD 10 million over five years in financial support to municipalities and regional transportation authorities for transportation demand management (TDM) projects to promote public transit. It also includes complementary activities to build awareness through school TDM programmes, bike-sharing guide, etc.
- The ecoTechnology for Vehicles Program invests CAD 15 million over four years to accelerate adoption of advanced vehicle technologies that reduce GHG emissions and fuel consumption in light-duty vehicles.
- The ecoENERGY for Personal Vehicles Program invests CAD 21 million over four years to provide assistance with buying, driving and maintaining cars to reduce fuel consumption and GHG emissions (*Fuel Consumption Guide*). The programme is in its third year of operation; over 440 000 new drivers have already been trained using materials from Auto$mart fuel-efficient driving initiative.
- The ecoFreight Program invests CAD 65 million over four years in various initiatives to reduce environmental and health impacts of freight transport, including:
  - National Harmonization Initiative for Trucking Industry;
  - Freight Technology Demonstration Fund for new technologies;
  - Freight Technology Incentives initiative to help defer costs of new technologies.

DOMESTIC AND COMMERCIAL APPLIANCES

To reduce air pollutant emissions from consumer and commercial products, the federal government is developing and will implement regulations under the Energy Efficiency Act. The amendments will include new energy performance standards for 18 currently unregulated products such as commercial washing machines and commercial boilers; and more stringent requirements for ten currently regulated products, such as dishwashers and dehumidifiers. The federal government is also implementing minimum performance standards for stand-by power use for certain consumer electronic products in two stages, starting in 2010.

RENEWABLE FUELS

Environment Canada estimates that the introduction of new regulations on renewable fuels, combined with provincial regulations, could reduce GHG emissions by 4 Mt per year. This will be done by introducing a 5% minimum renewable content based on volume of gasoline by 2010 and a minimum 2% renewable content in diesel and heating oil by 2012. This second target is contingent on the successful demonstration of renewable diesel fuel use under the full range of Canadian conditions. The federal government also announced funding of CAD 345 million to bolster the development of biofuels and other bio-products.

CANADA'S ECONOMIC ACTION PLAN AND THE CLEAN ENERGY FUND

In January 2009, the government tabled a comprehensive CAD 62 billion budget plan to stimulate economic growth and restore confidence during the global economic downturn. Canada's Economic Action Plan will invest CAD 5.1 billion in science and technology initiatives, including those relating to energy. Launched in May 2009, the Clean Energy Fund will invest CAD 850 million in technology development and demonstration, of which CAD 650 million for large-scale carbon capture and storage (CCS) demonstration projects.

WORKING WITH THE PROVINCES

BACKGROUND

The Canadian government has committed to working with provincial and territorial governments and key stakeholders to develop and implement a North America-wide cap-and-trade system for greenhouse gases and an effective international protocol for the post-2012 period. This system would seek to integrate the regional initiatives such as the Regional Greenhouse Gas Initiative and the Western Climate Initiative. The federal government is collaborating with the provinces and territories in a range of related policy areas, including energy efficiency, building codes, biofuels, renewable energy and science and technology (such as carbon capture and storage). Intergovernmental engagement and collaboration will continue to be an important element of the federal approach to climate change. There is a strong recognition of the need to align Canada and the United States and regional efforts are under way in this regard – Western Climate Initiative, Regional Greenhouse Gas Initiative, and climate registry – but the key is to respect regional needs with continental coherence.

Established in 2007, the Western Climate Initiative (WCI) is a collaborative partnership between seven American states and four Canadian provinces to reduce GHG emissions to 15% below 2005 levels by 2020 through the implementation of a regional cap-and-trade system.[13] In September 2008, the WCI released the outline design of its system. When fully implemented in 2015, this comprehensive programme is estimated to cover nearly 90% of the GHG emissions in WCI states and provinces. Québec and Ontario participate as observers in the Regional Greenhouse Gas Initiative (RGGI), a co-operative effort by ten states in the United States to limit GHG emissions.

Manitoba is a member of the Midwestern Greenhouse Gas Accord (MGGA) and Ontario observes also. In June 2009, the MGGA Advisory Board recommended a target of 20% below 2005 levels by 2020.

Furthermore, in Budget 2007, the government established the CAD 1.5 billion Clean Air and Climate Change Trust Fund to provide direct support to provincial and territorial efforts to reduce GHG and air pollutant emissions.

PROVINCIAL INITIATIVES

Alberta

Alberta is Canada's largest provincial emitter of GHG gases, emitting 234 Mt CO_2-eq in 2006 and was the first jurisdiction in North America to regulate industrial GHG emissions. Approximately 62% of 2006 emissions came from the energy sector; this sector includes electricity production, petroleum and natural gas extraction and refining, and oil-sands extraction and upgrading. Mindful of its context, the Alberta government released its updated Climate Change Strategy in January 2008.[14] The new approach builds on the 2002 *Albertans and Climate Change: Taking Action* plan and is focused on combining three approaches; implementing carbon capture and storage; greening energy production; and conserving and using energy more efficiently.

13. Between the states of Arizona, California, Montana, New Mexico, Oregon, Utah, Washington, and the provinces of British Columbia, Manitoba, Ontario and Québec.
14. *Alberta's 2008 Climate Change Strategy: Responsibility/Leadership/Action*, Government of Alberta, 2008.

The plan targets an emissions reduction of 50% below business-as-usual level by 2050 and 14% below 2005 levels while maintaining economic growth. By 2010, a 20 Mt reduction is planned. A major driver in achieving this reduction is the requirement for large industrial emitters to reduce their emission intensity by 12%, which commenced in July 2007. By 2020, the plan aims to stabilise greenhouse gas emissions with the implementation of new technologies.

In the absence of action, emissions in Alberta are expected to reach almost 400 Mt CO_2-eq by 2050 (business-as-usual scenario). Successful implementation of the plan is expected to yield 200 Mt of savings; conservation and energy efficiency, 24 Mt; greener energy production, 37 Mt; and carbon capture and storage, 139 Mt. Emissions in 2050 are therefore planned to be 14% below 2005 levels.

Alberta forecasts that CCS technology will deliver 70% of targeted emissions reductions by 2050; the bulk of these savings will come from activities related to oil-sands production, particularly upgrading.

In March 2008, the Alberta government announced the Alberta Carbon Capture and Storage Development Council, a partnership between governments, industry and scientific researchers. In July 2009, the Council published its final report, *Accelerating Carbon Capture and Storage Implementation in Alberta*,[15] which concludes that widespread deployment of CCS is not only achievable but has the potential to make a meaningful impact on greenhouse gas emissions in Alberta and in the world.

In July 2008, the government of Alberta committed to spending CAD 2 billion to fund large-scale CCS demonstration projects – one of the largest per-capita investments in CCS in the world. By the end of 2009, the government had signed letters of intent to provide funding for the Shell Quest, the TransAlta Pioneer, the Alberta Carbon Trunk Line, and the Swan Hills projects. Together, these projects are expected to capture about 4 to 5 Mt of carbon dioxide a year by 2015 (see Chapter 7 for more information).

In accordance with Alberta's Climate Change and Emissions Management Act (2007), companies that produce more than 100 000 tonnes of greenhouse gas emissions annually must reduce their emission intensity by 12% below a baseline calculated from each facility's emissions average over the years 2003, 2004 and 2005. Companies have three options in order to comply with the Act. They can: *i)* make in-house emissions reductions; *ii)* buy carbon credits in Alberta's offset system; or *iii)* contribute CAD 15 per tonne of GHG emitted to a technology fund administered by the Climate Change and Emissions Management Corporation (CCEMC). The CCEMC, which is an

15. *Accelerating Carbon Capture and Storage Implementation in Alberta*, Alberta Carbon Capture and Storage Development Council, 2009.

independent, not-for-profit organisation established in May 2009, administers this technology fund, "Investing in climate change knowledge, technology development, and operational deployment". To date, industry has contributed almost CAD 125 million to the fund and has made approximately ten megatonnes of reductions through operational changes and investing in verified offsets created by other Alberta projects.

In August 2009, the CCEMC announced its first Call for Proposals for GHG reduction projects. In mid-November, proponents with the most promising projects will be invited to submit full proposals by the end of January 2010. Successful proposals are expected to be identified in March 2010. With the exception of applied research and development, projects must take place in Alberta and preference will be given to projects where the lead applicant is from industry. Targeted investment areas for the fund are consistent with Alberta's climate change strategy: 50% of the funding will be invested in green energy production (*e.g.* fuel switching, and the implementation of renewable energy and alternative energy), 30% for carbon capture and storage (including sinks), and 20% for energy conservation and efficiency.

Ontario

Ontario is Canada's second-largest emitter of GHGs. In June 2007, the Ontario government launched *Ontario's Climate Change Action Plan*. The plan established province-wide emissions reduction targets and outlined policies and programmes to promote greater use of clean and renewable energy sources. The plan included a wide range of measures to reduce the carbon footprint of the Ontario government and the province's industrial, commercial, transportation, municipal and residential sectors. The plan established the following GHG reduction targets: 6% reduction (based on 1990 levels) by 2014, 15% by 2020 and 80% by 2050. The action plan also assigns the 2014 and 2020 GHG reduction targets to different sectors of the economy, the most significant of which will be the phasing-out of coal-fired generation.

Coal-fired electricity is one of the province's most significant sources of GHG emissions. Ontario will cease to burn coal at the four remaining coal-fired generating stations by the end of 2014. Coal replacement represents a reduction in GHG emissions of up to 30 Mt CO_2-eq, the single largest GHG reduction initiative in Canada. Ontario was the first jurisdiction in North America with a regulation in place to eliminate coal-fired power.

The Ontario Climate Change Secretariat was created in February 2008 to oversee implementation of the plan. The Secretariat's mandate is to provide comprehensive corporate leadership and to support government-wide collaboration. The Climate Change Secretariat works closely with different provincial ministries to design and build a system to track progress towards fulfilling the action plan's targets

The plan's first annual report, published in 2007, noted that Ontario's emissions in 2006, for which the most recent data were available, were lower than in 2004 and 2005, but were higher than in 1990.[16] The report attributed the decline in emissions compared to 2005 as a result of reduced use of coal-fired electricity, greater use of less carbon-intensive sources of electricity and lower demand for natural gas due to the milder 2006 winter.

Québec

With more than 48% of its total energy consumption coming from renewables and 98% of its electricity consumption coming from hydroelectricity, Québec has made green energy production a priority.

In June 2006, Québec established its first climate change action plan, entitled *Québec and Climate Change: A Challenge for the Future*. Québec aims to significantly reduce GHG emissions by 2012.

In 2007, Québec implemented the first carbon tax in North America. The tax applies to approximately 50 corporations that are fossil-fuel energy producers, distributors and refiners. These corporations pay a tax rate for every unit of fossil fuel that they distribute or produce. The tax rates are quite low: gasoline is taxed at CAD 0.008 per litre, diesel at CAD 0.009 per litre and coal at CAD 8.00 per tonne. Tax revenues are put into the provincial Green Fund to help facilitate reductions in GHG emissions and improve public transport with a CAD 200 million annual budget.

Québec has the lowest emissions rate per capita in Canada, and in 2009 set a goal to reduce emissions even further. This goal, similar to that established by the European Union, is a 20% reduction below 1990 levels. By 2020, Québec aims to have the smallest level of emissions per capita in North America.

To tackle the transport sector emissions, from 14 January 2010, Québec has applied California's stringent motor vehicle standards. Québec is the first and only Canadian province to apply these standards, among the strongest in North America.

Québec supports a cap-and-trade system and is largely involved in the Western Climate Initiative. Québec has also adopted legislation enabling it to be part of an international cap-and-trade system.

Other Provinces and Territories

The government of **British Columbia** (BC) has made mitigating climate change a top priority and, by means of the Greenhouse Gas Reduction Targets Act, has established legally-binding targets for GHG reduction. The legislation

16. *Ontario's Climate Change Action Plan Annual Report 2007-2008*, Ministry of the Environment, 2008.

requires provincial GHG emissions to be reduced by 33% below 2007 levels by 2020 and 80% below 2007 levels by 2050. In addition, legally binding targets have been established for 2012 and 2016, at 6 % and 18% compared to 2007 levels, respectively. In July 2008 BC implemented a revenue-neutral carbon tax on most fossil fuels.[17] The tax rate was initially assessed at CAD 10 per tonne of CO_2 with the tax increasing by CAD 5 in each subsequent year, levelling out at CAD 30 per tonne in 2012.[18] BC returns all carbon tax revenue through personal, small business and corporate tax cuts. Low-income British Columbians also receive a quarterly climate action tax credit indexed to the rate of inflation. At present, individuals and families earning less than CAD 30 600 and 35 700 per year respectively receive CAD 105 for each adult and CAD 31.50 for each child.

British Columbia currently serves as co-chair and Canadian liaison for the Western Climate Initiative and is the chair of the International Carbon Action Partnership. The province has also legislated that its entire public sector, including schools, universities, colleges and hospitals, will be carbon-neutral by 2010.

Saskatchewan is a relatively high per-capita emitter of greenhouse gases because of the energy-intensive nature of its economy. In 2009, the government of Saskatchewan introduced the Management and Reduction of Greenhouse Gases Act in the provincial legislature. The legislation established a plan for reducing GHG emissions to meet provincial targets and promote investments in low-carbon technologies. The Act provides for the establishment of a Saskatchewan Technology Fund to administer carbon compliance payments received from large emitters and to finance investments in low-emitting technologies and processes that reduce greenhouse gas emissions.

Other provinces and territories have also developed or are developing their own initiatives, some of which are trend-setting. In 2008, **Manitoba** introduced its Climate Change and Emissions Reductions Act. In 2008, **Prince Edward Island** released its new climate change strategy. **New Brunswick** has developed a Climate Change Action Plan for 2007-2012. **Newfoundland and Labrador** and **Nova Scotia** have also developed and started to implement provincial policies. In 2007 Nova Scotia legislated a mandatory GHG target (10% below 1990 level by 2020) and also established regulations in 2009 for 25% renewable energy requirement for electricity by 2015, and the first absolute GHG cap on electricity production in North America (25% reduction from today by 2020).

17. The tax is not applied to biofuels and renewable energy, fuels exported outside BC, fuel sold for inter-jurisdictional air travel, or land and marine shipping services. Furthermore, oil refining, coal mining, smelting, natural gas processing and piping, aluminium production and cement production are exempt from paying the tax.
18. As of January 2010, the tax is assessed at CAD 15 per tonne.

The northern territories – **Northwest Territories, Nunavut** and the **Yukon** – although not contributing in any significant way to Canadian emissions, remain acutely aware of the possible impact climate change can have on their unique physical environment. In response, each has developed policies, which include objectives such as: developing industry's best management practices in order to reduce GHG emissions, increasing renewable energy generation, increasing energy efficiency, managing emissions in the oil and gas sectors and exploring the possibility of amending or improving building codes.

NORTH AMERICAN INITIATIVES

United States-Canada Clean Energy Dialogue

In February 2009, Prime Minister Harper and President Obama launched the United States-Canada Clean Energy Dialogue (CED). The purpose of the CED is to enhance collaboration in addressing climate change and clean energy challenges. The two governments established three bilateral working groups to identify key opportunities for joint collaboration in each of the following priority areas:

- development and deployment of clean energy technologies, particularly carbon capture and storage (CCS);
- building a more efficient electricity grid based on clean and renewable power; and
- expanding clean energy research and development.

In August 2009, the CED working groups developed an action plan that outlines twenty projects for joint implementation. Action plan projects are focused on four broad types of activities:

- accelerate the development and demonstration of clean energy technologies;
- strive to develop compatible key regulatory standards;
- enhance collaborative research and development; and
- increase public awareness and outreach.

These projects are intended to advance bilateral co-operation in the CED's three priority areas. For example, Canada and the United States have agreed to form a United States-Canada CCS Collaboration. The Collaboration will engage Canadian and United States experts from the public and private sectors to share best practices and conduct joint activities on CCS.

To that end, under the United States-Canada Clean Energy Dialogue, the two countries have agreed to form United States-Canada CCS Collaboration under the current *Trilateral Energy Science and Technology Agreement (TESTA)* which can support United States-Canada or United States-Canada-Mexico co-operation.

The two governments have also committed to developing a Clean Energy Research, Development and Demonstration Collaboration Framework, and to collaborate on a technology road-map. This road-map will identify and describe the technology and associated pathways to allow Canada and the United States to meet their goals for reducing GHG emissions by 2050. In addition, both governments will collaborate on opportunities to upgrade the power grid, connect to clean energy sources, and promote the use of clean energy technologies.

While the framework and technology road-map will be essential to delivering research, development and demonstration (RD&D) collaboration initiatives, some specific projects and initiatives are ready to be launched immediately. These include joint work in sustainable bioenergy lifecycle analysis, production of biofuels using algae and trees infected by mountain-pine beetles, development of lightweight materials for vehicles, and advancement of tools to optimise energy performance in buildings.

The three bilateral working groups are focused on implementing these and other action plan projects, while remaining open to expanding work into other priority areas as deemed appropriate by both governments.

Minister Prentice and Secretary Chu (the Canadian and United States CED leads) presented their first report to Prime Minister Harper and President Obama on progress achieved under the Dialogue in September 2009. The next interim report to ministers from the working groups will be delivered in March 2010, with the second report to leaders expected by mid-2010.

In conclusion, the CED will capitalise on existing efforts in both countries, representing a co-ordinated effort to bring about a prosperous clean energy economy while addressing the challenge of climate change. Through their planned initiatives, the United States and Canada possess an important opportunity to work together in accelerating the development and deployment of clean energy technologies – all towards a clean energy future.

Asia-Pacific Partnership on Clean Development and Climate

The Asia-Pacific Partnership on Clean Development and Climate (APP) is a public-private partnership of seven countries – Australia, Canada, China, India, Japan, South Korea and the United States – that seeks to accelerate the development, deployment and diffusion of clean energy technologies. Canada joined the APP in October 2007 and has been an active member, participating in all Task Force and APP Policy and Implementation Committee (PIC) meetings.

APP partners have agreed to work together and with private-sector partners to meet goals for energy security, national air pollution reduction and climate change in ways that promote sustainable economic growth and poverty reduction.

REGIONAL AIR QUALITY

In Canada, the management of regional air quality is conducted primarily at the provincial and territorial levels. Provinces and territories implement different strategies for limiting emissions from facilities, ranging from regulatory to operating permit approaches.

Canada's industries lag behind those in the United States and other industrialised nations when comparing emission levels on a per-capita basis. However, overall air quality in Canada is generally better when compared to air quality in more heavily industrialised and populated countries. Recent analysis indicates that Canada has made steady improvements in air quality. Ozone, nitrous oxides (NO_x) and volatile organic compounds (VOCs) have decreased in Canada by about 50% since 1990. Emission concentrations of particulate matter ($PM_{2.5}$) have also shown a slight downward trend in concentrations during the same period and are projected to decline further over the next decade.

CRITIQUE

The federal, provincial and territorial governments of Canada share a strong commitment to the sustainable development of Canada's natural resources and have a long-standing and informed awareness of the dangers posed by climate change and the need for each to contribute to the development of a long-term solution.

Canada was one of the first countries to sign the Kyoto Protocol, in April 1998. Formal ratification came more than four years later, in December 2002, and with this the Canadian government committed to a Kyoto target of a 6% reduction in GHG emissions below 1990 levels. According to the most recent Greenhouse Gas Inventory report, total GHG emissions in Canada in 2007 were 747 Mt CO_2-eq (compared to about 592 Mt CO_2-eq in 1990).

Despite the ratification of the Kyoto Protocol, the election of a minority Conservative government in 2006 signalled a change in Canada's position. The focus of the government shifted to the development of its own Clean Air Agenda. By doing so, Canada was perceived to accept that it would not be in a position to meet its Kyoto commitments. An alternative approach to climate change policy, the *Turning the Corner* framework was published in 2007. This new framework introduced a revised target: to achieve a 20% GHG emissions reduction below 2006 levels by 2020 (equivalent to 3% below 1990 levels in Kyoto terms or approximately 574 Mt CO_2-eq) and a 60% to 70% reduction by 2050. With it, the government also developed a federal framework for reducing CO_2 emissions from designated existing industrial facilities, which would require an 18% reduction in carbon intensity by 2010 with a 2% intensity reduction per year thereafter. Other targets were to be applied to newer facilities. The government has also stated its ambition that 90% of domestic electricity will be provided by non-emitting sources by 2020. An Offset System for Greenhouse Gases is being developed and implemented. To further its national goals, the Canadian government continues to provide support for biofuels, wind and other renewable energy resources.

Canada remains in a difficult position, despite being an early mover in relation to international climate change mitigation initiatives; its economy remains inexorably linked to that of its most immediate neighbour. The United States is Canada's largest trading partner and the destination of the majority of its energy exports. In the absence of an agreed global solution, any emissions-related measures taken by the federal government, unmatched by parallel measures in the United States, stand to disadvantage the Canadian economy, at least in the short term. In 2009, therefore, given the global economic climate and presented with the opportunity of working more closely with the new United States Administration, the federal government took a decision to once more re-evaluate its approach to climate change mitigation, the *Turning the Corner* framework, albeit while continuing to pursue the regulation of industrial facilities. While the reasoning underlying this policy shift has been generally understood and accepted by many Canadians, it sends a confusing and perhaps negative signal to Canada's other industrialised partners. On this basis, therefore, we strongly encourage the federal government to maintain its very close dialogue with the United States and to develop a commitment to jointly participate in any agreed international solution. In this regard, the announcement in February 2009 of the commencement of a Clean Energy Dialogue between Canada and the United States with the intention of developing a possible future cap-and-trade system was a very welcome step. The government should build on this momentum and seek further opportunities for engagement and climate change policy co-ordination with the United States while continuing to develop its own initiatives. Furthermore, the announcement in January 2010 of the submission of its 2020 emissions reduction target under the Copenhagen Accord is another welcome step. Canada's 2020 target, an economy-wide 17% emissions reduction below 2005 levels, is aligned with the United States target. Canada will continue to work actively with its international partners to implement the Copenhagen Accord as the basis for a new, legally binding post-2012 climate change agreement.

The federal government has consulted regularly with provincial and territorial governments to develop and implement a comprehensive and effective national climate change plan. However, during the interim absence of an agreed long-term national solution, several provinces have independently taken steps to regulate GHG emissions, most notably Alberta and Ontario, but also in the other large emitting provinces such as Québec and British Columbia. In addition, some of these provinces have also been involved in cross-border regional developments. While this may bring very welcome benefits in the short term, care must be taken to ensure that the goals and objectives of each are consistent with the longer-term intentions of the federal government and any emerging international arrangements that Canada may be party to.

It is also important that, if Canada is to remain a leading exporter of energy, large investments in energy infrastructure, such as export pipelines and transmission lines, over the medium term will be needed. These investment requirements provide an opportune time for the federal government to articulate its climate change policy. Investors need clear signals regarding the shape and long-term viability of any emissions trading scheme that is likely to emerge. The government should quickly implement its intention to move from an emission intensity-based system to a fixed emissions cap system. In this regard, the announcement in early-2009 that thermal electricity producers in Canada are among those to be subject to a cap-and-trade regime is a welcome progress. Canada has committed to transposing the regulatory framework into law in 2010.

It also remains unclear how national targets are to be co-ordinated, divided and enforced among provinces and territories (including the role, if any, of a cap-and-trade system, renewable energy standards and low-carbon fuel standards). Recognising the strong powers of the provincial governments in determining their own energy and environmental policies, the federal government should provide leadership and facilitate a multilateral dialogue between provinces and territories to enable a harmonised and co-ordinated Canadian system. That system should be one that provides clear market-based signals and maintains Canada's competitive advantage. The federal government should also secure a binding statutory commitment for its targets and strengthen co-ordination between federal and provincial energy and environment ministers, perhaps by the establishment of a joint secretariat to co-ordinate their work.

The launch of the Clean Energy Fund as part of the federal government's 2009 Economic Action Plan is a welcome step. The fund will invest CAD 850 million in technology development and demonstration, including CAD 650 million for large-scale carbon capture and storage (CCS) demonstration projects. Given the significant role that CCS is likely to play in the longer-term emissions landscape, this investment provides a welcome signal.

RECOMMENDATIONS

The government of Canada should:

- *Continue to maintain a high-level dialogue with the provinces and territories to agree to a mechanism that will enable Canada to come forward with a co-ordinated climate change policy, including specific cap-and-trade proposals, and actively participate in any forthcoming international agreement.*
- *Build on the momentum from the Canada-US Clean Energy Dialogue and seek further opportunities for engagement and climate change policy co-ordination with the United States.*
- *Clarify whether existing federal and provincial laws and regulations are sufficient for the federal government and provinces to make binding climate change commitments and comply with them.*

ENERGY EFFICIENCY

OVERVIEW

Canada has higher energy intensity, adjusted for purchasing power parity (PPP), than any IEA country. This is largely due to its high concentration of output in energy-intensive sectors, cold climate, large distances and high standard of living, with minimal constraints on space occupation. Final energy consumption has grown continuously over the past decade, though at a slower rate than the economy as a whole (Figure 8).

Energy intensity has been improving as a result, dropping at an average rate of 1.3% per year between 1990 and 2007 adjusted for PPP (Figure 9). The majority of annual intensity improvements from 1990 to 2006 were due to energy efficiency gains, with the rest resulting from changes in sector mix. Canada is aiming to improve efficiency in the transport sector, one of the largest energy-consuming sectors, with recent legislation regulating the fuel efficiency of cars and light trucks.

INSTITUTIONAL OVERSIGHT

The federal government sets energy efficiency standards for new light-duty motor vehicles and equipment. It plays a key role in establishing consistent approaches for efficiency rating systems, labelling schemes, training and information services across Canada. It also facilitates energy efficiency activities through capital cost allowance tax breaks, consumer rebates, and incentives.

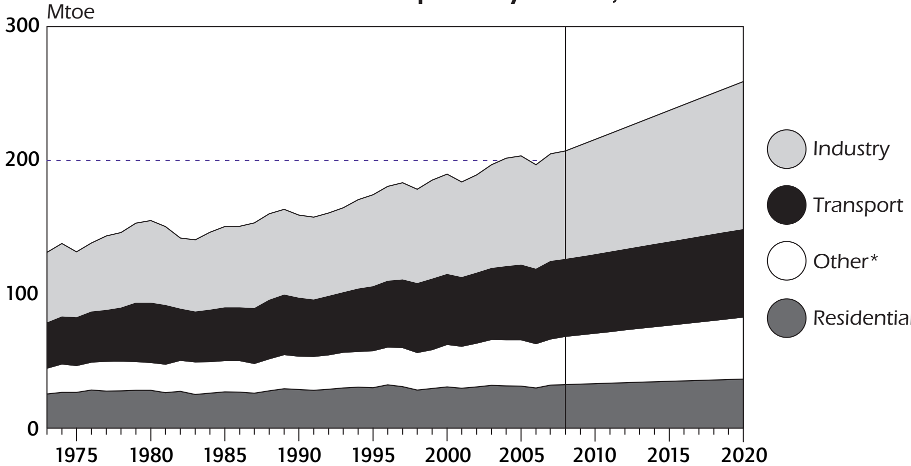
Provinces and territories have the ability to set the institutional framework for demand-side management, regulate energy utilities through public utility commissions, and regulate energy efficiency standards for building designs, building components, and energy-using equipment. In addition, provincial fiscal and resource policies can help shift investment and purchasing behaviour towards energy efficiency. Finally, provinces and territories can stimulate the marketplace with their own equipment purchasing, and building and vehicle leasing policies.

Municipalities and local administrations can shape communities' energy use, particularly for transportation, given the land-use planning impacts on commuting distances and on complete communities. In addition, communities enforce building code standards on behalf of provinces and territories, and thus have a large impact on the construction industry. Similarly, First Nations communities influence planning and managing transportation and building code standards on, and in some cases, of First Nations land.

In 1991, NRCan launched the National Energy Use Database (NEUD) initiative to help the federal government strengthen its knowledge of energy consumption and energy efficiency. The NEUD plays a number of significant roles directly related to NRCan's ecoENERGY Efficiency initiatives; however, its most important role is to secure the development of a reliable information base on energy consumption for all energy-consuming sectors.

Figure 8

Total Final Consumption by Sector, 1973 to 2020

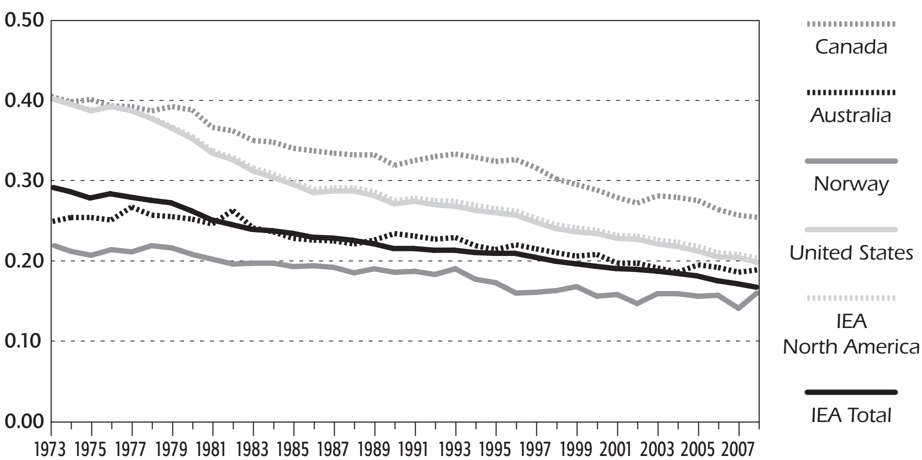


* includes commercial, public service, agricultural, fishing and other non-specified sectors.
Sources: *Energy Balances of OECD Countries*, IEA/OECD Paris, 2009 and country submission.

Figure 9

Energy Intensity in Canada and in Other Selected IEA Member Countries, 1973 to 2008*

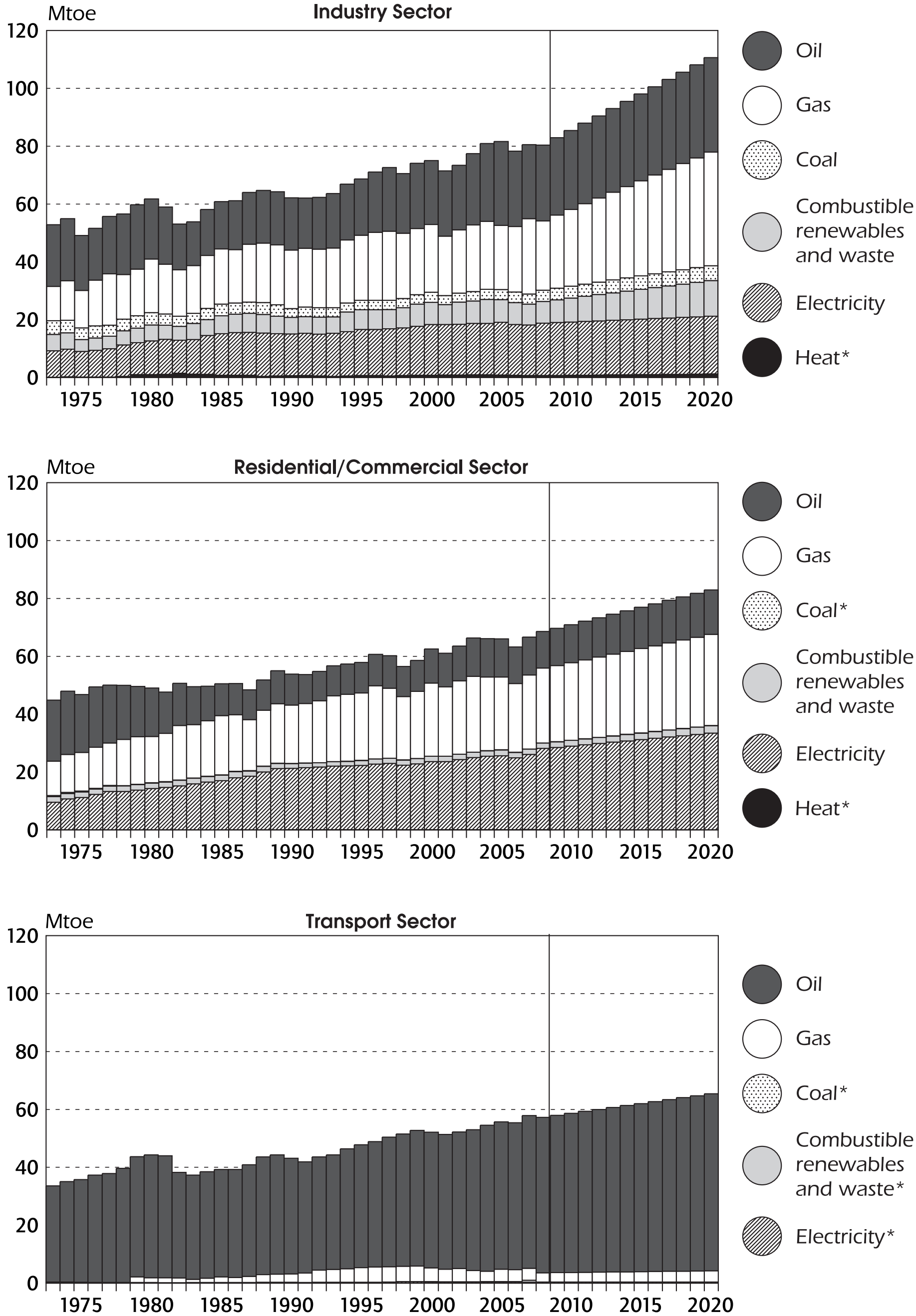
(toe per thousand USD at 2000 prices and purchasing power parities)



* 2008 = estimates.
Sources: *Energy Balances of OECD Countries, IEA/OECD Paris, 2009 and National Accounts of OECD Countries*, OECD Paris.

Figure 10

Total Final Consumption by Sector and by Source, 1973 to 2020



* negligible.

Sources: *Energy Balances of OECD Countries*, IEA/OECD Paris, 2009 and country submission.

POLICIES AND MEASURES

REGULATORY PROCESS

The federal Energy Efficiency Act, passed by Parliament in 1992, provides for the creation and enforcement of regulations concerning minimum energy performance levels for energy-using products, as well as the labelling of energy-using products and the collection of data on energy use. Provincial and territorial governments, municipalities, utilities and some non-governmental organisations also contribute to energy efficiency policies through their own set of programmes and regulations.

The first Energy Efficiency Regulations came into effect in February 1995, following extensive consultations with the provincial governments, affected industries, utilities, environmental groups and others. The regulations establish energy efficiency standards for a wide range of energy-using products, with the objective of eliminating the least efficient products from the Canadian market. They apply to energy-using products imported into or manufactured in Canada and shipped from one province to another. The regulations continue to apply to any energy-using product even if that product is merely a component of another product.

The regulations are administered by NRCan and are amended on a regular basis to strengthen existing performance standards or to introduce performance standards for new products. As part of the regulatory process, the Office of Energy Efficiency (part of NRCan) consults stakeholders by making public its intentions and providing access to draft proposals.

POLICIES

The Office of Energy Efficiency (OEE) is Canada's centre of excellence for energy conservation, efficiency and alternative fuels information. The OEE is mandated to strengthen and expand Canada's commitment to energy efficiency in order to help address the federal government's policy objectives. In addition, the OEE offers grants and incentives and other resources, including workshops for professionals, statistics and analysis, awards and hundreds of free publications.

In 2007, the Council of Energy Ministers published *Moving Forward on Energy Efficiency in Canada*. The purpose of the document was to provide political leadership to energy efficiency efforts across the country and to offer a range of tools for realising Canada's energy efficiency potential. This document, which recognised significant potential for energy efficiency improvements, represented the collaborative efforts of provincial and territorial governments, federal government and a wide cross-section of non-governmental organisations and industry.

In September 2009, the Council of Energy Ministers approved the release of four tools and initiatives to improve energy efficiency across Canada. These included a guide for the trucking industry to improve energy savings through aerodynamic devices; a manual and tool to help industry track and manage its energy use; tools for recommissioning of buildings, and development of an energy benchmarking database for buildings; and, finally, a road-map for considering energy supply and use at the community level. Interested jurisdictions can adopt the tools for their own use through their own programmes and measures as they see fit.

The ecoENERGY Efficiency Initiative was introduced by the federal government in 2007 as a key part of its overall ecoACTION strategy. The federal government is investing more than CAD 675 million between 2007 and 2011 to promote the more efficient use of energy across all sectors of the economy. The ecoENERGY Efficiency Initiative is comprised of a number of programmes, each targeted on a specific sector.

These measures are also part of the government's climate change strategy, *Turning the Corner*, which also includes expectations to increase the average fuel efficiency in new cars by 20% and to improve Canada's overall energy efficiency by 20%. *Turning the Corner* also proposes the introduction of new energy efficiency requirements for a wide range of commercial and consumer products and new national performance standards.

A CAD 32 million regulatory agenda, under the authority of the Energy Efficiency Act, will introduce or raise energy efficiency standards for a wide range of energy-using products. As a result, 80% of energy consumption in homes and businesses will be regulated. While energy efficiency standards take the worst-performing equipment out of the marketplace entirely, ENERGY STAR® labelling complements the standards by leading consumers to the best-performing equipment.

In December 2008, the federal government published the first of three planned amendments to the Energy Efficiency Regulations. This first amendment includes standards to address the efficiency of general service lighting. Canada will phase out the use of inefficient incandescent lamps and impose high-efficiency standards for gas furnaces, the most common heating device in the country. The second of the three amendments, expected to be pre-published by April 2010, will add standards to specifically address stand-by power consumption in some common consumer items and establish or revise minimum energy performance standards for another twelve products.

ecoENERGY EFFICIENCY INITIATIVE PROGRAMMES

The **ecoENERGY Retrofit** is a CAD 520 million programme offering financial support to implement energy-saving projects. The programme was launched in April 2007 and is available to home-owners, along with small and medium-sized businesses and organisations in the form of financial support to retrofit homes, buildings and industrial processes.

From April 2007 to the end of fiscal year 2008/09, grants were made to 94 000 home-owners under the **ecoENERGY Retrofit for Homes** component to support energy efficiency upgrades through the Homes component of the ecoENERGY Retrofit programme. The Homes component will help participants reduce their annual energy consumption by about 23% and GHG emissions by approximately 3.4 tonnes per house per year. All regions of Canada, except one province and one territory, offer matching programmes, allowing home-owners to avail themselves of two concurrent sources of finance.

The ecoENERGY Retrofit for Small and Medium-Sized Organisations (SMO) component of the programme is targeted on small and medium-sized organisations in the commercial, institutional and industrial sectors. The scheme was recently extended to continue to March 2012, subject to the availability of funding. The programme provides finance to help accelerate the implementation of energy efficiency improvements in order to contribute to cleaner air, reduced GHG emissions, lower energy bills, increased competitiveness and a healthier, more comfortable workplace.

In the building sector, the scheme is targeted at commercial and public institutions such as office space, retail, hospitality, schools, universities and health care centres. Also eligible are multi-residential dwelling units that are four storeys or higher and do not exceed 20 000 square metres in area.

In the industry sector, the scheme is targeted on industrial facilities that will not be subject to GHG emissions regulations and have fewer than 500 employees in the building to be retrofitted. To be eligible, the company must also be registered with the Canadian Industry Program for Energy Conservation (CIPEC) as a CIPEC leader.

The SMO provides financial incentives for the implementation of pre-approved retrofit activities and will pay eligible organisations CAD 10 per gigajoule (GJ) of energy estimated to be saved by a retrofit project to a maximum of the lesser of:

- 25% of the total eligible project costs (including taxes net of tax rebate and other incentives; or CAD 50 000); or
- the amount required to reduce the net simple payback period for each project to no less than one year.

ecoENERGY for Buildings and Houses is a CAD 60 million programme to encourage the construction and retrofit of more energy-efficient buildings and houses. Under the programme, provincial and territorial energy ministers have approved the development of an energy-rating and labelling system to help building owners measure the energy performance of commercial and institutional buildings. The system allows comparison of buildings to other similar facilities in their region or across Canada. The Office of Energy Efficiency (OEE) has been working under the guidance of participating provinces, territories and other key stakeholders to develop this system.

National Resources Canada offers a free service that validates the energy performance level of a building design. NRCan validates the designs of new buildings, building additions and major renovations in the commercial, institutional and government sectors. Eligible buildings also include multi-unit residential buildings with at least four storeys or a footprint of at least 600 square metres and a common entrance.

The **ENERGY STAR® for New Homes** activity promotes energy efficiency guidelines that enable new homes to be approximately 30% more energy-efficient than those built to minimum provincial building codes. This initiative is currently available in Ontario and Saskatchewan.

ecoENERGY for Fleets is a CAD 22 million programme that focuses on reducing fuel use and GHG emissions in commercial and institutional fleets through a variety of methods: training and education; sharing best practices; anti-idling campaigns; and technical demonstrations to identify opportunities for improvements. In 2008/09, three Idling Awareness Campaigns were completed, 451 school bus drivers were trained in SmartDriver practices and 170 fleets participated in twelve *Fuel Management 101* workshops to promote greater uptake of transportation energy efficiency practices. Federal-provincial collaboration has also been initiated on best practices and rating systems for heavy-duty vehicles (class 8 trucks and equipment).

The CAD 21 million **ecoENERGY for Personal Vehicles** programme provides Canadians with helpful tips and decision-making tools on buying, driving and maintaining their vehicles to reduce fuel consumption and GHG emissions. The ecoENERGY for Personal Vehicles driver education initiative has helped train more than 440 000 novice drivers annually in fuel-efficient driving practices in 2008/09. The *Fuel Consumption Guide* rating the fuel efficiency of all light-duty vehicles was released to more than 3 300 car dealerships across Canada.

As part of this programme, the government is also working directly with car manufacturers to significantly reduce transportation GHG emissions by 2010. Through a voluntary agreement, the automobile industry has committed to reducing annual GHG emissions from passenger cars and light-duty trucks by 5.3 Mt by 2010. This is in preparation for mandatory fuel efficiency regulations that will come into force for the 2011 model year as part of the Clean Air Regulatory Agenda.

BUILDINGS

For over a decade, Canada has implemented energy efficiency standards for new buildings by means of building codes that are enforced and regularly updated. Energy efficiency standards for new buildings are determined following consultation between the federal government and other levels of government. The more stringent National Energy Code for Buildings and Houses will address energy efficiency standards for new buildings across Canada by ensuring that new houses and buildings will be 25% more energy-efficient by 2011 than current practices provide.

Under Canada's Constitution Act, building regulation is the responsibility of provincial and territorial governments. The Model National Energy Code of Canada for Buildings 1997 (MNECB) contains cost-effective minimum requirements for energy efficiency in new buildings. The MNECB applies to all buildings, other than houses of three storeys or less, and to additions of more than 10 m^2 to such buildings. The MNECB is prepared under the auspices of the Canadian Commission on Building and Fire Codes (CCBFC) and was first published in 1997 by the National Research Council Canada (NRC). After consultation with provinces, territories and stakeholders, the CCBFC agreed at its February 2007 meeting to update the MNECB 1997. This project is made possible by collaboration between Natural Resources Canada and the NRC. They are working together, along with the provinces and territories, to support the work for the updating of the MNECB.

The next edition of the MNECB is scheduled to be released in 2011. The Code will be published in an objective-based format, which will offer new information to facilitate the evaluation of innovative products and systems. The first step in the compilation of the objective-based material for the updated MNECB will be the analysis of all the provisions in the 1997 edition.

In addition, Canada systematically collects data on energy use and energy efficiency across all sectors. The Commercial and Institutional Consumption of Energy Survey (CICES) collects data on the energy consumption of commercial and institutional establishments in Canada. The Survey is conducted by Statistics Canada for the Office of Energy Efficiency (OEE) of Natural Resources Canada and is consistent with OEE's mandate to strengthen and expand Canada's commitment to energy efficiency. In recent years, energy use statistics have been published in relation to energy efficiency trends in Canada, energy consumption of major household appliances shipped in Canada and energy use in the Canadian manufacturing sector. A report on the energy consumption of Canada's on-road vehicle fleet, examining its composition, the main characteristics of vehicles in Canada and their use for the reference year 2007, was also published and is available on the OEE website.

INDUSTRY AND UTILITIES

The Canadian Industry Program for Energy Conservation (CIPEC), sponsored by Natural Resources Canada (NRCan), has developed a benchmarking and best practices programme for the industrial sector. The programme is designed to help industry achieve significant energy efficiency gains.

The programme involves the development of quantitative and qualitative indicators through the collection and analysis of energy-related data and energy management practices. CIPEC, in collaboration with its association partners, has established indicators to enable industrial companies to compare their energy use, GHG emissions and practices with similar operations. These indicators can help guide industry towards achieving greater energy efficiency by identifying energy cost-saving opportunities for each industrial sector.

TRANSPORT

The road transport sector is the largest energy-consuming sector. In 2008, total final consumption of energy was 207 Mtoe, of which the transport sector consumed 57.3 Mtoe or 27.7%.

Canadians use light-duty vehicles as the main mode of transportation for personal passenger transport. Air and rail modes are also used, but to a much lesser extent. Light-duty vehicles include small cars, large cars, light trucks and motorcycles. For the passenger transportation subsector, NRCan measures energy use in passenger-kilometres (pkm).

Passenger transportation energy use increased by 16% between 1990 and 2005. At the same time, Canada saw a 24% increase in the number of licensed drivers and a 13% increase in the passenger-vehicle stock (light-duty vehicles). There was a 10% increase in the average distance travelled (by light-duty vehicles). Combined, these factors led to a 34% increase in passenger-kilometres travelled.

The rise in the popularity of minivans and sports utility vehicles led to a large shift in passenger transportation from cars towards light trucks. Between 1990 and 2005, light-truck energy use increased more than any other passenger transportation mode, rising by 98%. The light-truck stock grew by 88% and its passenger-kilometres grew by 141% over the period.

The mix of fuels used for passenger transport remained relatively constant over time. Motor gasoline was the primary source of energy, representing 77% of the fuel mix in 2005, followed by aviation turbo-fuel and diesel fuel. Energy intensity associated with passenger travel has improved from year to year. Between 1990 and 2005, energy intensity improved by 13% thanks to improvements in vehicle fuel efficiency.

In addition to the programmes previously mentioned, the 2-year ecoAUTO Rebate Program ended in March 2009. The ecoAUTO Rebate Program was a scheme designed to encourage potential buyers to purchase new fuel-efficient vehicles. Between March 2007 and December 2008 applicants who purchased or leased (12 months or more) eligible 2006, 2007 and 2008 model-year, fuel-efficient vehicles were eligible to receive rebates ranging from CAD 1 000 to CAD 2 000. The scheme received over 182 300 applications and issued over 169 800 rebates totalling CAD 191.2 million.

NRCan also provides driving tips and vehicle maintenance tips in an effort to promote more fuel-efficient practices. The department also promotes the annual ecoENERGY for Vehicles Awards, administered by the Office of Energy Efficiency, which are presented for the most fuel-efficient vehicles for the current model year. Complementary to the awards is a tool available on the NRCan website that allows potential buyers to compare the fuel consumption of various makes and models of vehicles for a specific model year and to select the most fuel-efficient vehicle that meets their needs.

DOMESTIC APPLIANCES

Regulations have now been established for more than 40 products, including major household appliances, water heaters, heating and air-conditioning equipment, automatic icemakers, dehumidifiers, dry-type transformers, electric motors of below 200 horsepower, heat pumps, beverage-vending machines, commercial refrigeration, general service and other lighting, exit signs, and traffic signals. The Energy Efficiency Act was amended in May 2009 to allow energy efficiency standards for products that affect energy consumption. When fully implemented, the current regulatory agenda will result in standards for products that use 80% of the energy consumed in the residential and commercial/institutional building sectors.

ENERGY STAR®

ENERGY STAR® is a voluntary arrangement between the OEE and organisations that manufacture, sell or promote products that meet certain standards of energy performance. Natural Resources Canada is the administrator of the ENERGY STAR® programme under a formal agreement with the United States Environmental Protection Agency and the United States Department of Energy. The presence of the ENERGY STAR® mark indicates that the product or appliance meets a premium level of energy efficiency, making it easier for consumers to choose the most energy-efficient products. Many of the products regulated under Canada's Energy Efficiency Regulations must exceed the minimum performance standards to qualify for ENERGY STAR®. Products not covered by the Regulations must achieve similar premium levels of energy efficiency. Most products, but not all, that qualify in the United States automatically qualify in Canada.

The OEE promotes the international ENERGY STAR® symbol in Canada and monitors its use. Major manufacturers and retailers of energy-efficient products, utilities and energy retailers have recognised the benefits of ENERGY STAR® to consumers and have joined in promoting the symbol. Products that display the symbol have been tested according to prescribed procedures and have been found to meet or exceed higher energy efficiency levels without compromising performance.

Federal, provincial and territorial governments collaborate in different ways to achieve energy efficiency objectives. Provincial and territorial governments, as well as utilities, use federal energy efficiency tools to complement their own energy efficiency programmes and policies.

- In **British Columbia**, the LiveSmart BC and the Energy Efficient Buildings Strategy: More Action, Less Energy made CAD 160 million in funding available to energy efficiency programmes and set new targets to maximise energy efficiency, conserve energy and reduce GHG emissions.
- **Ontario's** Green Energy and Green Economy Act, 2009 (GEA) received Royal Assent in May 2009. Regulations and other tools needed to fully implement the legislation were introduced in September 2009. The GEA makes energy efficiency a key part of Ontario's building code and provides that a Building Code Energy Advisory Council be established with a mandate to advise the Minister of Municipal Affairs and Housing on the Building Code with reference to standards for energy conservation.
- **Ontario's** Green Energy Act also makes the greening of Ontario government and broader public sector buildings/facilities a priority by establishing the Leadership in Energy and Environmental Design (LEED) Silver as the standard, requiring the development of energy conservation plans throughout the broader public sector, making home energy audits mandatory prior to the sale of homes and establishing mandatory electricity conservation targets for local distribution companies. The province has a target of at least 6 300 MW reduction in peak demand by 2025, representing most of the anticipated load growth in the province in that period. Ontario regulates the minimum energy performance of over 50 products to the highest North American levels and will be establishing ENERGY STAR® levels as the minimum for most household appliances.
- In 2007, **Québec** established its 2015 energy strategy, which targets savings of 11 TWh by 2015. To achieve this target, the Québec government asked the *Agence de l'efficacité énergétique* and all the Québec energy distributors to collaborate and prepare a Master Plan on Energy Efficiency and New Technologies.[19] Furthermore, in January 2010, Québec began to apply motor vehicle standards equivalent to those found in California, North America's strictest standards.
- **New Brunswick's** Expanded Existing Homes Upgrades Program offers home-owners a grant of up to CAD 2 000 or an interest-free loan of up to CAD 10 000 to make energy efficiency improvements to their home.

19. The target for energy efficiency for Hydro-Québec has been increased from 4.1 to 8.0 TWh and the target date was extended from 2010 to 2015. For Gaz Métro and Gazifère, the government has demanded an increase of the target to 96.9 million cubic metres. In the sector of petroleum products, the target has been fixed at 2 million tonnes. *Using Energy - Québec Energy Strategy 2006-2015 To Build the Québec of Tomorrow*, Québec Ministry for Natural Resources and Wildlife, July 2009.

- Under **Manitoba's** Green Building Policy, government-funded projects in the province will have to be Leadership in Energy and Environmental Design (LEED) Silver – a high performance level in an environmental building-rating system.
- A government-funded long-term care facility being built in the City of Corner Brook, **Newfoundland** has achieved a LEED Silver Standard. This building will be the benchmark for public-sector buildings in the province wherever it is achievable.
- **Alberta's** 2008 Energy Strategy includes important proposals in relation to energy efficiency.[20] The strategy commits to the adoption of energy conservation measures in buildings and a more energy-conscious approach to urban planning. The province has committed to work with the federal government to establish vehicle emission/efficiency guidelines and to invest in projects that provide cleaner options to consumers, including mass transit. The province has also committed to support, through planning, technology and education, the realisation of greater efficiency in the production, conversion and consumption of energy.
- **Alberta's** adoption of the LEED Silver standard for design of new government-funded buildings will reduce the environmental impacts of new buildings and help conserve energy. In addition, energy retrofit of over 200 provincial government facilities since 1995 has already resulted in annual savings of CAD 6 million from lower utility costs.
- The government of **Nunavut** has launched its Energy Management Plan to retrofit government-owned buildings in Iqaluit to make them more energy-efficient. The private sector is investing CAD 10 million to retrofit 29% of the government-owned building stock and will recoup the cost from energy savings over the next three years.
- In continuing efforts to lead by example, **Saskatchewan's** Energy and Climate Change Plan, released in 2007, committed the province to expanding purchases of green power, improving the emission standard for provincial government vehicles, developing a new efficiency code for government buildings, and ensuring sustainable practices are a part of all provincial government planning.
- In **Nova Scotia**, the City of Halifax has instituted a Bus Rapid Transit (BRT) system. This project established two BRT corridors from outlying areas to downtown Halifax. These corridors are equipped with transit priority traffic signals and queue-jump lanes, allowing transit to have a competitive edge over vehicular traffic at certain signalised intersections. The new buses offer an attractive fare and are fitted with extra amenities such as padded seating and air-conditioning. Public reception has been overwhelmingly positive and the service has been oversubscribed, resulting in plans to significantly expand the service.

20. *Launching Alberta's Energy Future - Provincial Energy Strategy*. Government of Alberta, December 2008.

- The **Northwest Territories'** Energy Efficiency Incentive Program encourages residents to buy the most energy-efficient products by providing rebates for energy-efficient home heating, home appliances, home renovations and personal transportation such as eligible outboard motors, snowmobiles and vehicles.
- The **Yukon** government offers a broad range of incentives to help consumers reduce their energy consumption. Both home-owners and rental property owners are eligible for low-cost energy evaluations, interest-free loans for energy efficiency upgrades and rebates on high-efficiency appliances. Through its storefront Energy Solutions Centre, it also provides training for building designers and trades people.

Box 1

IEA G8 Energy Efficiency Recommendations

At the Group of Eight* (G8) Summit in 2005 in Gleneagles, Scotland, the G8 countries asked the IEA to assist in developing and implementing energy efficiency policies. Responding to this request, the IEA subsequently prepared a set of energy efficiency policy recommendations covering 25 fields of action across seven priority areas: cross-sectoral activity, buildings, appliances, lighting, transport, industry and power utilities. These 25 recommendations were presented to the summit of the G8 in Hokkaido, Japan in July 2008. The fields of action are outlined below.

1. The IEA recommends action on *energy efficiency* across sectors. In particular, the IEA calls for action on:
   - Measures for increasing investment in energy efficiency.
   - National energy efficiency strategies and goals.
   - Compliance, monitoring, enforcement and evaluation of energy efficiency measures.
   - Energy efficiency indicators.
   - Monitoring and reporting progress with the IEA energy efficiency recommendations themselves.
2. *Buildings* account for about 40% of energy used in most countries. To save a significant portion of this energy, the IEA recommends action on:
   - Building codes for new buildings.
   - Passive energy houses and zero-energy buildings.
   - Policy packages to promote energy efficiency in existing buildings.
   - Building certification schemes.
   - Energy efficiency improvements in glazed areas.

3. *Appliances and equipment* represent one of the fastest growing energy loads in most countries. The IEA recommends action on:
   - Mandatory energy performance requirements or labels.
   - Low-power modes, including stand-by power, for electronic and networked equipment.
   - Televisions and set-top boxes.
   - Energy performance test standards and measurement protocols.

4. Saving energy by adopting efficient *lighting technology* is very cost-effective. The IEA recommends action on:
   - Best-practice lighting and the phase-out of incandescent bulbs.
   - Ensuring least-cost lighting in non-residential buildings and the phase-out of inefficient fuel-based lighting.

5. About 60% of world oil is consumed in the *transport sector*. To achieve significant savings in this sector, the IEA recommends action on:
   - Fuel-efficient tyres.
   - Mandatory fuel efficiency standards for light-duty vehicles.
   - Fuel economy of heavy-duty vehicles.
   - Eco-driving.

6. In order to improve energy efficiency in *industry,* action is needed on:
   - Collection of high-quality energy efficiency data for industry.
   - Energy performance of electric motors.
   - Assistance in developing energy management capability.
   - Policy packages to promote energy efficiency in small and medium-sized enterprises.

7. *Energy utilities* can play an important role in promoting energy efficiency. Action is needed to promote utility end-use energy efficiency schemes.

Implementation of IEA energy efficiency recommendations can lead to huge cost-effective energy and CO_2 savings. The IEA estimates that, if implemented globally without delay, the proposed actions could save around 8.2 Gt CO_2/yr by 2030. This is equivalent to one-fifth of global energy-related CO_2 emissions in 2030 under the IEA Reference Scenario, in which no new policies are adopted or implemented. Taken together, these measures set out an ambitious road-map for improving energy efficiency on a global scale

* The Group of Eight is an international forum for the governments of Canada, France, Germany, Italy, Japan, Russia, the United Kingdom and the United States.

CRITIQUE

Canada's primary energy and electricity consumption per unit of GDP is the highest among IEA countries. This is largely due to its high concentration of output in energy-intensive sectors, cold climate and high living standards with minimal constraints on space occupation. Final energy consumption has grown continuously over the past decade, though at a slower rate than the economy as a whole. Energy intensity has been improving as a result, dropping at an average rate of 1.3% per year between 1990 and 2006.

Canada is committed to improving and increasing energy efficiency. In August 2008, Canadian provinces and territories collectively committed to achieving a 20% increase in energy efficiency by 2020, largely through improvements to building codes, broader regulation of energy-using products, green building policies for new government-funded facilities, and home energy audits and retrofit assistance. In addition, federal and provincial or territorial governments are collaborating in different ways to achieve combined energy efficiency objectives.

In common with many other parts of the Canadian energy sector, a significant challenge faced by federal policy makers is the separation of powers between the federal and provincial/territorial levels. Energy management and production are under provincial/territorial jurisdiction; therefore, the federal government has not been in a position to establish national targets for energy efficiency. Instead, it has developed and implemented a series of national programmes and standards to encourage higher levels of energy efficiency throughout the country. It ensures that energy efficiency remains at the heart of the broader national climate change strategy and regularly convenes provincial and territorial policy makers to discuss strategic energy efficiency policies and best practices.

Provincial and territorial governments are using federal energy efficiency tools to complement their own energy efficiency programmes and policies. Canada is a world leader in the development and analysis of energy efficiency indicators. The federal government, through the Office of Energy Efficiency (OEE), works to improve energy conservation and energy efficiency in every sector of the Canadian economy. The OEE has developed a series of ecoENERGY programmes to help and promote the efficient use of energy and the annual federal budgetary processes have provided significant funding for energy efficiency programmes. The ecoENERGY Efficiency Initiative is investing more than CAD 675 million between 2007 and 2011 to promote smarter energy use throughout the Canadian economy. Regulations under the Energy Efficiency Act, in effect since 1995, set minimum energy-performance levels for a number of energy-using products such as appliances, lighting, and heating and air-conditioning products.

The most recent amendment to the Energy Efficiency Regulations, published in December 2008, included national standards for lighting efficiency. The new standard will phase out inefficient incandescent general service lighting by

2012. As part of the Regulatory 2009 Plan, the federal government proposed to update existing standards for 12 product categories and to introduce new energy efficiency standards for 20 more between 2007 and 2010.

The ecoENERGY for Buildings and Houses programme includes a package of instruments. These include new design tools and training so that designers, builders, owners and operators can learn about and use best practices, new technologies, and energy-rating and labelling systems. The Model National Energy Code for Buildings is being updated in co-operation with provinces and territories, with a view to encourage other levels of government to adopt more stringent building energy codes by 2010/11.

Transport is the sector which contributes by far the largest share of Canada's projected business-as-usual GHG emissions in 2030, and it is also the sector with the largest growth. Progress is being made in the sector by using a combination of voluntary standards for vehicle fuel efficiency that are harmonised with United States fuel efficiency regulations, a voluntary Memorandum of Understanding with the Canadian automotive industry to reduce GHG emissions through to 2012 and federally promoted eco-driving and tyre maintenance schemes. This success should be built upon and further attention given to two areas: consideration needs to be given primarily to mandatory fitting of tyre-pressure monitoring systems (TPMS) and strengthening the fuel efficiency requirement. Explicit regulations for the fuel economy of heavy-duty vehicles are also needed.

The regulation of vehicle emissions remains a primary concern for Canada's climate change policies, but the country lacks mandatory regulation or incentives for vehicle CO_2 reductions at federal or provincial level. In April 2009, the federal government issued a notice of intent to regulate these emissions starting with the 2011 model year. The federal government has announced that, to ensure that the automobile industry remains competitive; it is working with the United States towards the development and implementation of common North American standards. The large distances and climate variations in Canada inevitably affect vehicle choice but large efficiencies are possible without loss of amenity. The government of Canada should move to set up its own vehicle emission standards and incentives having regard to best international practice in the United States and elsewhere. Explicit regulations for the fuel economy of heavy-duty vehicles should also be considered.

Across sectors, co-operation between provincial and federal energy ministers on developing a national energy efficiency action plan could be further strengthened. The Foundation for Action policy document agreed by Canada's Council of Energy Ministers in 2007 provided a basis for further co-operation. Unfortunately, the document cannot provide a clear nationwide strategy on energy efficiency. Nonetheless, several provinces have established energy efficiency targets within provincial-level strategies. However, this is not the case in all provinces and territories and, where adopted, timeframes and measurements are somewhat inconsistent. In this context, national targets and/or harmonised measurements and timeframes would be desirable to help maximise opportunities for energy savings across the country.

At the 2009 IEA Ministerial Meeting, the IEA recommended the adoption of a broad range of specific energy efficiency policy measures. The recommendations (see Box 1) cover 25 fields of action across seven priority areas and were originally developed by the IEA in 2007 under the G8 Gleneagles Plan of Action. The 25 recommendations are considered by the IEA Secretariat and member countries as a useful compilation of best-practice policies. To improve energy efficiency, the IEA encourages Canada to continue to implement these recommendations and similar measures where appropriate to national circumstances.

RECOMMENDATIONS

The government of Canada should:

- *Take a firm co-ordinating role and enhance the consultation process between the federal government, provinces and territories in order to develop and implement to the greatest extent possible, and in collaboration with the provinces and territories, a comprehensive joint national energy efficiency strategy, consistent with emerging climate change policy.*
- *Develop transparent energy efficiency targets/objectives for the main sectors of the economy, working with provinces and territories to try to standardise to the degree possible across sectors, and make energy efficiency policy an active part of any new climate change policy.*
- *Consider developing new market-based measures to give clear price signals to energy consumers, especially in sectors that may not be included in a future cap-and-trade scheme.*

PART II

SECTOR ANALYSIS

RENEWABLE ENERGY

OVERVIEW

Canada, one of the largest and geographically diverse OECD member countries, possesses substantial renewable energy, including hydropower, biomass, and wind, solar, geothermal and ocean energy (Figures 11 and 12). Total primary energy supply of Canada was 272.7 Mtoe in 2008, of which 44 Mtoe or 16.1% came from renewable sources.

Canada is the OECD's largest producer of electricity from hydropower, but rests among the lowest in the OECD in terms of non-hydro renewables, with wind and solid biomass the only other sources of note. Hydropower contributed 372.5 GWh to electricity production in 2008. In 2007, almost 62% of Canada's electricity generating capacity came from renewable energy, of which hydropower accounted for 57.6% (73.4 GW), wind energy represented 0.5% (1.8 GW) and solid biomass accounted for 1.3% (1.6 GW). Solar photovoltaic (26 MW) and tidal energy (20 MW) represented a very small portion of Canada's electricity capacity.

DIVISION OF RESPONSIBILITIES

With the exception of hydropower and ocean energy, provincial governments have exclusive jurisdiction over the development and management of renewable energy resources within their respective boundaries. Under the federal Fisheries Act, the federal government has jurisdiction over hydropower and ocean energy to the extent that these activities impact fishery resources. At the federal level, the Renewable and Electrical Energy Division (REED) of Natural Resources Canada (NRCan) is responsible for developing and implementing policies and programmes aimed at increasing the deployment of renewable energy technologies for electricity and heat generation. NRCan also undertakes research and development in alternative energy technologies and renewable fuels by means of CanmetENERGY (the clean energy research and technology development agency) and the Fuels Policy and Programs Division, both under the Energy Technology and Programs Sector.

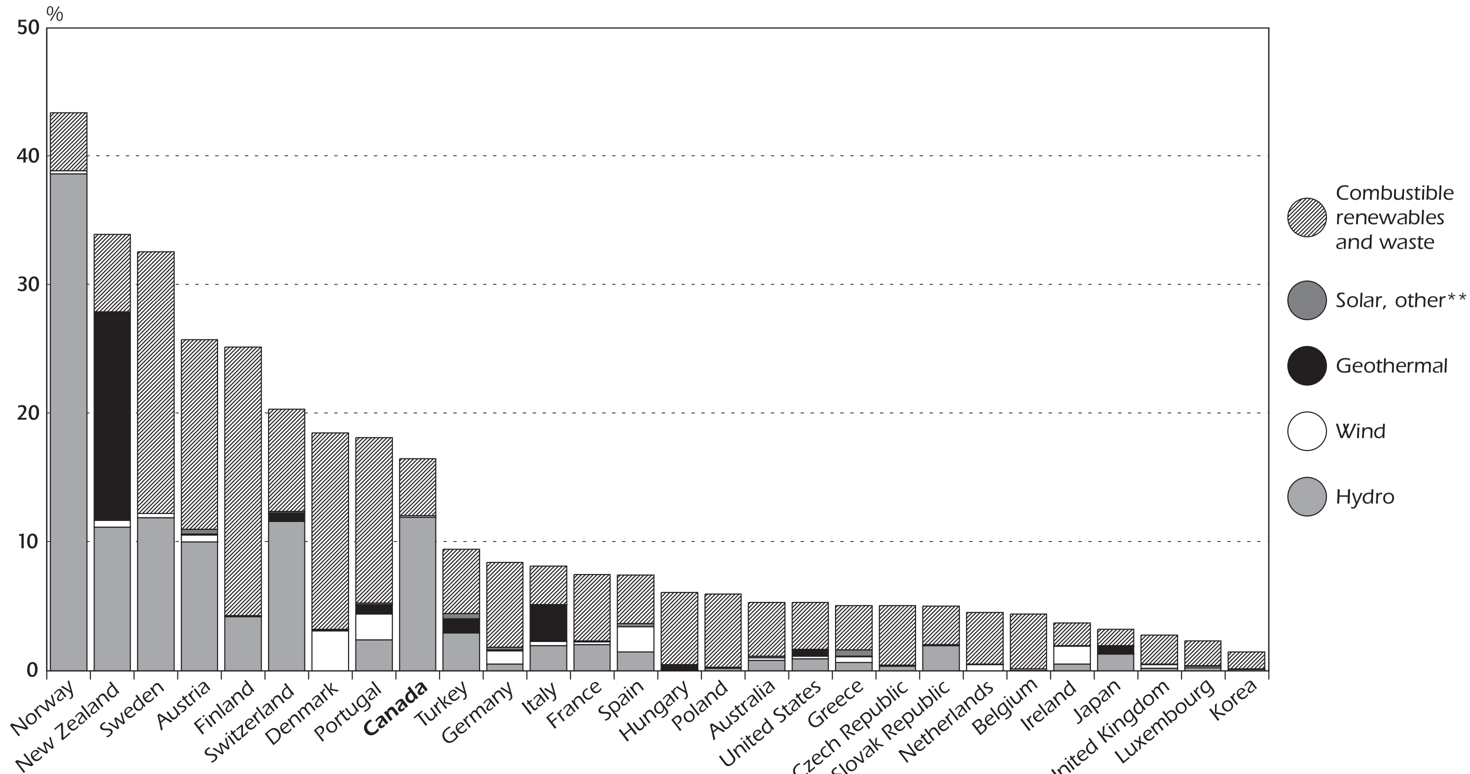
POLICIES

RENEWABLES PROMOTION POLICIES

The federal government has instituted a number of programmes to promote the development of some types of renewable energy. Between 2004 and 2009, several federal programmes to support the renewable sector have expired, including:

Figure 11

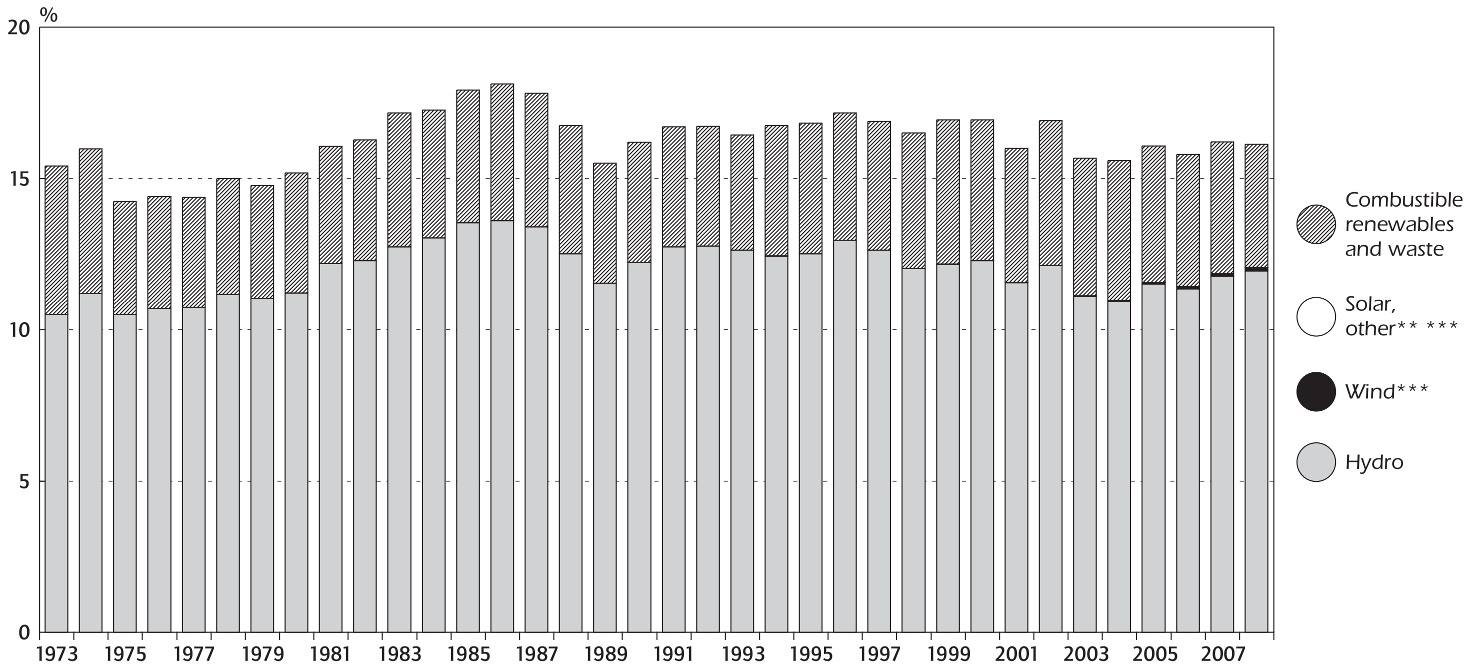
Renewable Energy as a Percentage of Total Primary Energy Supply in IEA Member Countries, 2008*



* estimates.
** other includes tide and wave.
Source: *Energy Balances of OECD Countries*, IEA/OECD Paris, 2009.

Figure 12

Renewable Energy as a Percentage of Total Primary Energy Supply, 1973 to 2008*



* 2008 = estimates.
** other includes tide and wave.
*** negligible.
Source: *Energy Balances of OECD Countries*, IEA/OECD Paris, 2009.

- Wind Power Production Incentive (WPPI);
- Renewable Energy Deployment Initiative (REDI);
- Market Incentive Program for Distributors of Emerging Renewable Electricity Sources (MIP); and
- Purchases of Electricity from Renewable Resources (PERR) Programme.

In their place, the federal government has established a number of new initiatives. In general, these programmes fall under three headings: market assistance, fiscal measures, and research and development.

FEDERAL MARKET ASSISTANCE PROGRAMMES

In 2007, the federal government announced a number of ecoENERGY Initiatives. These programmes provide almost CAD 4 billion in funding to assist the development of a more sustainable energy system. The initiatives include a four-year, CAD 1.5 billion investment to increase the supply of renewable energy from a number of sources.

The programme consists of two parts. The **ecoENERGY for Renewable Power** programme offers eligible renewable energy projects (those commissioned before March 2011), a production incentive of CAD 0.01 per kilowatt-hour for up to 10 years. This represents an investment of approximately CAD 1.48 billion over 14 years, and will support the installation of up to 4 000 MW of new capacity. The four-year, CAD 36 million **ecoENERGY for Renewable Heat** programme will offer industrial, commercial and institutional consumers various incentives to install active energy-efficient solar-air and/or water heating systems. In addition, the Renewable Heat programme includes a CAD 9 million pilot project to support large-scale residential solar-water heater deployment and new standards, codes and training for the solar thermal and geothermal industries.

FISCAL MEASURES

There are two principal fiscal measures that provide support for investment in the production of electricity from renewable sources. First, under the Federal Income Tax Act, equipment that is designed to produce energy from renewable sources is eligible for an accelerated capital cost allowance (ACCA) at 50% on a declining basis. Secondly, for projects using these renewable energy technologies, many start-up expenses qualify as Canadian Renewable and Conservation Expenses (CRCE) that may be deducted in full in the year incurred, carried forward to future years or transferred to investors using flow-through shares.

SUPPORT FOR RESEARCH AND DEVELOPMENT

Canada's energy research and development activities are focused towards increasing the efficiency of emerging technologies and reducing their cost. The **ecoENERGY Technology Initiative** provides CAD 230 million to fund research, development and demonstration to support the development of next-generation clean energy technologies. The initiative provides funding towards the development of technologies for producing and using renewable energy from clean sources such as wind, solar, tidal, and biomass. In addition, the federal government sustains two funds to support the development and demonstration of innovative technological solutions operated by Sustainable Development Technology Canada (SDTC), a not-for-profit foundation that supports the development of clean technologies. The Sustainable Development (SD) Tech Fund is a CAD 550-million scheme aimed at supporting the late-stage development and pre-commercial demonstration of clean technology solutions: products and processes that contribute to clean air, clean water and clean land, which address climate change and improve the productivity and competitiveness of Canadian industry.

RENEWABLE ELECTRICITY IN THE PROVINCES AND TERRITORIES

ONTARIO

Ontario has conducted three competitive procurements of large-scale renewable energy projects, which yielded a total of 1 600 MW of renewable electricity generating capacity. In November 2006, the Ontario Power Authority (OPA) announced a Renewable Energy Standard Offer Program (RESOP) that offers 20-year contracts to projects of 10 MW or less. For wind, biomass and hydro, prices are CAD 0.11 per kilowatt-hour (kWh) with 20% of the price indexed to the Ontario Consumer Price Index (CPI). For solar-photovoltaic projects, the price is CAD 0.42 per kWh. Projects that demonstrate that they can operate reliably during peak hours will be paid an additional CAD 0.0352 per kWh for electricity delivered during peak hours. Since December 2008, Ontario has executed 427 RESOP contracts totalling more than 1 400 MW of capacity.

In 2005, the Ontario government announced an ambitious plan to install smart electricity meters in all homes and small businesses by the end of 2010. By 2011, the majority of low-volume consumers are expected to be supplied with electricity at time-of-use rates. The Smart Metering System Implementation Program (SMSIP), facilitated by the Independent Electricity System Operator (IESO), provides a delivery framework to support the provincial government's objectives.

A net metering programme is also in place, which allows electricity generated from small-scale renewable installations to be exported to the electrical network in return for a credit towards the producer's electricity bill.

Green Energy and Green Economy Act, 2009

In May 2009, the Ontario legislature passed the Green Energy and Green Economy Act, 2009, a significant piece of legislation intended to attract new investment, create new green economy jobs and better protect the environment. The Act and related amendments to other legislation received Royal Assent on 14 May 2009. The legislation was the result of consultations with stakeholders, including public comment on its provisions through both legislative hearings and posting on Ontario's environmental registry. Key elements of the legislation (and related policy) include:

- Streamlined approvals for renewable energy projects, encouraging investment in renewable energy while working with municipalities and ensuring strong protection for health, safety and community consultation.
- Mandatory (unless waived by buyer) home energy audits prior to the sale of homes.
- Opportunities for municipalities, First Nations and Métis communities to build, own and operate their own renewable energy projects.
- New programmes for municipalities, communities and aboriginal groups to ensure that some project costs associated with community renewable energy projects can be recovered.
- Establishment of an academic research chair to examine potential public health effects of renewable energy projects.
- Important responsibilities for the Ontario Energy Board and other entities in achieving the province's objectives of conservation, promotion of renewable generation, and technological innovation through the smart grid.
- A feed-in tariff system, which will provide guaranteed prices for renewable energy projects, including a focus on helping companies, farmers, co-ops and other groups navigate the approvals process, creating Ontario jobs, and developing a smart grid which, among its benefits, will support this new energy supply.
- The feed-in tariff, based on successful European schemes, will introduce a new power purchasing programme with guaranteed 20-year pricing and no upper limit on project scale. The tariff will replace the existing RESOP and is the first of its kind in North America. The feed-in tariff also includes a price adder for aboriginal and community projects to encourage greater participation.

Table 6

Feed-in Tariff Prices for Renewable Energy Projects in Ontario

(base date: 24 September 2009)

Technology	*Size tranches*	*Contract price CAD/kWh*
Biomass	< or = 10 MW	0.138
	> 10 MW	0.130
Biogas		
On-farm	< or = 100 kW	0.195
On-farm	> 100 kW < or = 250 kW	0.185
	< or = 500 kW	0.160
	> 500 kW or < = 10 MW	0.147
	> 10 MW	0.104
Water power	< or = 10 MW	0.131
	> 10 MW < or = 50 MW	0.122
Landfill gas	< or = 10 MW	0.111
	> 10 MW	0.103
Solar PV		
Rooftop	< or = 10 kWh	0.802
Rooftop	10 - 100 kWh	0.713
Rooftop	101 - 500 kWh	0.635
Rooftop	> 500 kWh	0.539
Gound mounted	< or = 10 MW	0.443
Wind		
Offshore	Any size	0.135
Onshore	Any size	0.190

Source: Feed-in Tariff Programme. Programme Overview, Version 1.1, Ontario Power Authority, September 2009.

The prices offered will differ according to project size and type of renewable technology. They will include capital, operating and maintenance costs and allow for a reasonable rate of return on a 20-year investment. The feed-in tariff programme includes requirements for domestic content, which would ensure at least 25% of the overall goods and services content of wind projects and 50% of the overall goods and services content of large solar projects produced in Ontario. These requirements will increase in January 2011 to 60% for solar and in January 2012 to 50% for wind.

BRITISH COLUMBIA

In an effort to add renewable electricity capacity to British Columbia's generation portfolio, BC Hydro is purchasing power from independent power producers whose projects meet detailed green criteria. To date, these projects have involved well-established technologies utilising resources such as small-scale hydro and biomass.

Since 2000, BC Hydro has issued four Calls for Power for varying amounts of renewable energy, wherein independent power producers bid into a generation process. By November 2008, BC Hydro had received 68 proposals from 43 registered proponents in response to the most recent Clean Power Call. In aggregate, the 68 proposals represent a total firm energy output of approximately 17 000 GWh per year from 45 hydro projects, 19 wind projects, two waste heat projects, one biogas project, and one biomass project. In November 2009, BC Hydro short-listed 47 proposals and decided to advance with post-proposal discussions with the 13 proponents whose projects have been identified as the most cost-effective. BC Hydro contacted the proponents of the other 34 short-listed proposals in November 2009 to afford them an opportunity to make their proposals more cost-effective.

In another scheme, BC Hydro is implementing a Standing Offer Program (SOP) to encourage the development of small and clean energy projects throughout the province. The programme is a mechanism to purchase energy from small projects with a nameplate capacity between 0.05 MW and 10 MW. BC Hydro will pay for each megawatt-hour of energy delivered a tariff based on a number of different factors. The programme does not have an initial target volume or quota and the need for total or annual volume caps will be reviewed after the first two years of the programme, some time in the first half of 2010.

In 2008, the province announced plans to roll out smart meters to every home and business in British Columbia within 5 years. The Smart Metering and Infrastructure Program includes a Smart Metering Project – an initiative to replace the existing 1.8 million customer meters, including those in remote communities, with new digital meters that support 2-way communications capability. Installation will take until the end of 2012 and will cost up to CAD 530 million in upfront capital costs.

OTHER PROVINCES AND TERRITORIES

Alberta's Nine-Point Bioenergy Plan, released in October 2006, has CAD 239 million in programme funding in place from 2006 to 2011. The funding provides monies for three programmes: the Bio-refining, Commercialization and Market Development Program, the Bioenergy Infrastructure Development Program and the Bioenergy Producer Credit Program (BPCP). These programmes focus on commercialisation, production capacity, infrastructure and production for bioenergy, including biofuels and bioelectricity. The province is reviewing the BPCP for possible extension beyond 2011. It has also implemented a policy and regulation for micro-generators with capacity of less than 1 MW intended mainly for own use. This regulation enables micro-generators to receive credit for surplus electricity fed into the grid. The province is also developing an alternative and renewable energy policy framework.

Manitoba is implementing a policy to develop 1 000 MW of wind within the next decade assuming the economic feasibility of future wind projects.

Manitoba Climate Change legislation restricts the operation of the province's only remaining coal-fired generating facility for emergency use only.

Québec released its Energy Strategy[21] in 2006. With approximately half of its total energy consumption coming from renewables, Québec is planning to go even further. Jointly with its Plan Nord[22] objectives, more than 7 500 MW of hydroelectric power and 4 300 MW of wind power will be implemented on the grid before 2035. Biomass and cellulosic ethanol both play a role in the Energy Strategy which, in total, is estimated to generate more than CAD 70 billion of investment. With a focus on local economic development, its requests for proposal have a mandatory requirement on local content, a requirement that has boosted manufacturing capabilities in remote regions of the province.

The Atlantic Provinces – **Prince Edward Island, Nova Scotia**, and **New Brunswick** – are the only jurisdictions to have implemented legislated Renewable Portfolio Standards (RPS). Prince Edward Island has set a 30% standard to be achieved by 2016; Nova Scotia has set a standard of 5% of new emerging renewable energy by 2012 and 10% by 2013; and New Brunswick a 10% standard by 2013.

In October 2008, the government of Prince Edward Island announced the province's wind energy strategy entitled Island Wind Energy, Securing Our Future: The 10-Point Plan. The province's goal is to establish 500 MW of wind power, installed in the province, by 2013. The 10-Point Plan sets clear ground rules and establishes a fair, open and transparent process for developers.

RENEWABLES PROMOTION POLICY: BIOFUELS IN TRANSPORT

REGULATION OF BIOFUELS

In December 2006, Environment Canada published a Notice of Intent (NOI) outlining the federal government's intention to regulate the mandatory renewable content of fuels in Canada. Regulations under Canadian Environmental Protection Act (CEPA) 1999 will require fuel producers and importers to have an average annual renewable fuel content of at least 5% of the volume of gasoline that they produce or import, commencing in 2010. In addition, the government intends to require an average 2% renewable fuel content in diesel fuel and heating oil, no later than 2012, upon successful demonstration of renewable diesel fuel use under the range of Canadian conditions.

Environment Canada has estimated that the incremental impact of the federal regulation to existing and announced provincial regulations would be around 1.3 billion litres of additional ethanol and 0.5 billion litres of

21. http://www.mrnf.gouv.qc.ca/english/energy/strategy/index.jsp (last accessed 31 December 2009).
22. http://www.plannord.gouv.qc.ca/english/index.asp (last accessed 31 December 2009).

additional biodiesel, resulting in an incremental annual GHG emissions reduction of 2.7 Mt CO_2-eq. Since then, British Columbia announced its intent to regulate 5% renewable content in the gasoline and diesel pool. As a result, Environment Canada has updated the estimated annual GHG emissions reductions associated with the federal regulation to 1.9 Mt. The total volume of renewable fuel expected to be required under the regulation is around 2.2 billion litres of ethanol and 0.6 billion litres of biodiesel for a total annual GHG emissions reduction of around 4 Mt (these volumes of renewable fuels were calculated by Environment Canada using the forecasts for gasoline and diesel demand provided by Natural Resources Canada).

In addition, Alberta recently announced a Renewable Fuels Standard (RFS) of 2% renewable diesel in diesel fuel and 5% ethanol or other fuel alcohol in gasoline, starting in late 2010. The RFS will be calculated on an annual average blend basis and applies to fuel placed in the Alberta market. To meet the mandate, Alberta will require approximately 300 million litres of ethanol or fuel alcohol and 110 million litres of renewable diesel annually. Alberta's RFS is the first in North America to require renewable fuel used to support the RFS to demonstrate net reduction of greenhouse gas emissions. Under the Alberta RFS, renewable fuel must show a greenhouse gas emissions reduction of at least 25% on a lifecycle basis compared to the fossil fuel it replaces.

SUPPORT FOR BIOFUELS

ecoENERGY for Biofuels and the **NextGen Fund** are key elements of the federal government's Renewable Fuels Strategy (RFS). The RFS has four major components: increasing the retail availability of renewable fuels by means of regulation; supporting the expansion of Canadian production of renewable fuels; assisting farmers to seize new opportunities in the sector; and accelerating the commercialisation of new technologies using non-conventional feed stocks. The RFS is complementary to existing research, development and deployment programmes within the federal government.

The ecoENERGY for Biofuels Initiative supports the production of renewable alternatives to gasoline and diesel and encourages the development of a competitive domestic industry for renewable fuels. ecoENERGY for Biofuels will invest up to CAD 1.5 billion over nine years in support of biofuels production in Canada.

Sustainable Development Technology Canada has launched the CAD 500 million NextGen Fund that invests in establishing large-scale demonstration facilities to produce next generation renewable fuels, such as cellulosic ethanol. This funding is in addition to the CAD 200 million **ecoAGRICULTURE Biofuels Capital Initiative**, a programme to assist farmers and rural communities seize new market opportunities in the biofuels and bio-products sectors.

The ecoAGRICULTURE Biofuels Capital Initiative (ecoABC) is a new CAD 200 million initiative. It offers repayable contributions of up to

CAD 25 million per project to help farmers overcome the challenges of raising the capital necessary for the construction or expansion of biofuels production facilities. It has been operational since April 2007. To date, four contribution agreements have been entered into, to the value of approximately CAD 34.6 million.

Announced in 2006, the **Biofuels Opportunities for Producers Initiative** assisted agricultural producers in developing sound business proposals, and in undertaking feasibility or other studies to expand biofuels production capacity. The initiative ended in March 2008. Over the course of the programme, 121 projects were provided with support totalling CAD 18.2 million.

In addition, Budget 2008 provided CAD 10 million over two years for scientific research and analysis on biofuels emissions to support development and demonstration projects to verify that renewable diesel fuel is safe and effective for the Canadian climate. The budget also provided funding to establish a pilot programme to demonstrate E85 fuelling infrastructure and promote its commercialisation. E85 is a renewable fuel containing 85% ethanol and 15% gasoline.

GHGENIUS MODEL

In order to enable the appropriate assessment of transportation fuels under representative Canadian conditions, NRCan supports and maintains the GHGenius model. GHGenius was developed to analyse lifecycle energy use and greenhouse gas (GHG) emissions from both conventional and alternative fuels.

GHGenius is capable of modelling all appropriate lifecycle stages of transportation fuels. For ethanol this includes: the growing and harvesting of grains; fertiliser manufacture; land-use changes, including nitrous oxide emissions associated with fertiliser application; feedstock transportation to a production facility; production of ethanol from corn, including distillation, co-products, fuel storage, distribution and transport; fuel dispensing; and vehicle operation, including carbon released during vehicle operation offset by carbon sequestered during crop growth. GHGenius also considers the energy and emissions associated with materials used in vehicles and vehicle assembly. It can be accessed on a publicly available website.[23]

HEATING AND COOLING

The **ecoENERGY for Renewable Heat** programme is a four-year investment of CAD 36 million to increase the use of renewable thermal energy by industry, commercial businesses and institutions and to boost the amount of renewable thermal energy created for these sectors.

23. http://www.ghgenius.ca/ (last accessed on 31 December 2009).

The ecoENERGY for Renewable Heat programme runs from April 2007 to March 2011. Incentives are offered to the industrial/commercial/institutional sector to install active energy-efficient solar-air and/or water heating systems. Eligible projects must be completed and commissioned within nine months of the signing of a contribution agreement with NRCan.

Table 7

Federal Government Support Schemes for Renewable Energy

Initiative	*Description*	*Funding*	*Status*
The ecoENERGY for Renewable Power programme	This 4-year programme is supporting clean electricity from renewable sources such as wind, biomass, low-impact hydro, geothermal, solar photovoltaic and ocean energy. The programme provides a production incentive of CAD 0.01 per kWh for up to 10 years for electricity generated from eligible renewable energy projects. The programme will add up to 14.3 TWh of new electricity from renewable energy sources.	CAD 1.5 billion	The programme runs from 1 April 2007 to 31 March 2011
The ecoENERGY Technology Initiative	The ecoENERGY Technology Initiative is a four-year programme to fund research, development and demonstration of clean energy technologies. This initiative is being delivered as a single, integrated programme – research, development and demonstration – covering the innovation spectrum from basic research to near-commercialisation of technologies. The programme is focusing on priority technology areas to support the development and demonstration of the next generation of clean energy technologies – technologies that currently do not exist, or that are at a very early stage of development. This policy targets all sources of clean energy, including renewable energy sources.	CAD 230 million	The programme runs from 1 April 2007 to 31 March 2011
The ecoENERGY for Renewable Heat programme	This is a four-year investment to increase the use of renewable thermal energy by industry, commercial businesses and institutions; boost the amount of renewable thermal energy created for these sectors; and contribute to cleaner air by helping Canadian businesses use less fossil fuel-based energy for space and water heating in buildings across the country.	CAD 36 million	The programme runs from 1 April 2007 to 31 March 2011

Table 7

Federal Government Support Schemes for Renewable Energy
(continued)

Initiative	*Description*	*Funding*	*Status*
The Accelerated Capital Cost Allowance (ACCA)	The Accelerated Capital Cost Allowance (ACCA), under Class 43.1 and 43.2 of Schedule II to the Income Tax Regulations, allows investors an accelerated write-off of certain equipments used to produce energy in a more efficient way or to produce energy from alternative renewable sources.		In force
Canadian Renewable and Conservation Expenses (CRCE)	Canadian Renewable and Conservation Expenses (CRCE) is a category of fully deductible expenditures associated with the start-up of renewable energy and energy conservation projects for which at least 50% of the capital costs of the property would be described in Class 43.1 and 43.2. These expenditures may be deducted in full in the year incurred, carried forward indefinitely, or transferred to investors using flow-through shares.		In force
Renewable Fuels Strategy (RFS)	The Minister of the Environment intends to propose a draft Renewable Fuels Regulation in Part I of the *Canada Gazette* by late 2009. This regulation would require fuel producers and importers to have an average annual renewable fuel content equal to 5% of the volume of gasoline that they produce or import, commencing in 2010. It is intended that the regulation also puts in place an additional requirement for 2% renewable fuel content in diesel fuel and heating oil by no later than 2012, upon successful demonstration of biodiesel use under the range of Canadian conditions.		Under development
The ecoENERGY for Biofuels Initiative	This 9-year programme provides operating incentives to producers of renewable alternatives to gasoline and diesel until 2017.	CAD 1.5 billion	
Offset System for Greenhouse Gases	In August of 2008, a draft version of Canada's Offset System for Greenhouse Gases, was published. This programme recognises verified voluntary action to reduce greenhouse gases from non-regulated activities. The Offset System will provide tradable credits in recognition of real, incremental, quantified, verified and unique greenhouse gas reductions from activities that are within the scope of the Offset System.		Under development

Source: NRCan.

Renewable energy can play a fundamental role in tackling climate change, environmental degradation and energy security. Canada possesses substantial renewable energy and, at present, makes good use of some of these renewable resources, which account for 16.1% of total primary energy supply (TPES). Renewable energy accounts for 76.9 GW (62%) of Canada's electricity generating capacity, 73.4 GW of which comes from hydropower. In 2008, this renewable capacity provided 62% (372.5 TWh) of electricity production. While the overall contribution of hydropower to energy supply is high, considerable potential for increased penetration of other forms of renewable energy remains. Likely climate change obligations and the federal government's commitment to a low-carbon energy supply have led to efforts, by the federal government and the provinces, to increase the share of renewable energy in electricity generating capacity, heating and transportation fuels.

Although hydropower is the most readily available form of renewable energy, interest in other renewable technologies continues to grow, particularly in the wind power sector. While the federal government has instituted a number of programmes to promote the development of some types of renewable energy, provincial governments have exclusive jurisdiction over the development and management of energy resources in their respective provinces.

The deployment of renewable energies can make a major contribution to the reduction of energy-based GHG emissions. In this sense, the federal government must place renewable energy as a strategic option for Canadian energy policy. Specific provincial policies also endeavour to boost renewable energy supply, and in this regard the enactment of the Ontario Green Energy Act represents a major step forward and provides a useful model to other provinces.

It is also helpful that the Council of the Federation has recognised the need to take a leadership role in creating innovative energy policies and facilitate the development of renewable, green and cleaner energy sources to meet future demand and to contribute to environmental goals and priorities.[24] Recognition of the need to promote greater intergovernmental collaboration for development and implementation of new and expanded renewable, green and cleaner energy sources and technologies represents good progress.

Nonetheless, developers of renewable energy projects have to deal with thirteen different jurisdictions when investing in renewable energy and this may limit opportunities to fully benefit from cross-border opportunities. There

24. *A Shared Vision for Energy in Canada*, the Council of the Federation, August 2007. The Council of the Federation was created by Premiers of the provinces and territories to play a leadership role in revitalising the Canadian federation and building a more constructive and co-operative federal system.

is a greater need to address this: the federal government should take an active and leading role, possibly by means of the Council of Energy Ministers, to work with the provinces to ensure that developments in each province or territory contribute in some way towards national goals and the streamlining of environmental regulatory processes.

It is widely understood that many renewable energies still need support; be it fiscal, directly by means of funding towards research and development, or the availability of feed-in-tariffs, quota or obligation systems, perhaps linked to tradable green certificates. Previous IEA analysis suggests that the success or otherwise of any renewables policy is directly linked to three key factors: the country's level of policy ambition, *e.g.* in terms of established renewable energy targets; the presence of a well-designed incentive scheme; and the capability of overcoming non-economic barriers, which can prevent the proper functioning of the market and ultimately limit the effects of the policies in place. High policy effectiveness indicators are generally observed in those countries where all three factors coexist at the same time.[25] Conversely, if any one of the three key factors is missing, this is likely to cause failure of the policy, regardless of the specific incentive scheme in place and, to some extent, of the level of economic support provided.

At the moment, renewable energy sources receive various methods of financial support. Clean energy generation benefits from federal Accelerated Capital Cost Allowances. Renewable energy development is further encouraged through the ecoENERGY Initiatives. At present, the federal government supports renewables-based electricity by means of the ecoENERGY for Renewable Power programme (CAD 0.01 per kWh for up to 10 years). However, a long-lasting renewable energy support system is needed and so is a clear commitment in favour of supporting the growth of renewable energy. Many of the programmes currently in place are of a short duration (around five years) and will soon expire. The federal government should consider extending the life of those programmes deemed to have the potential to deliver the greatest energy savings in the longer term and ensure any new programmes are of longer duration.

Regulations under development by Environment Canada will require 5% renewable fuel content based on the gasoline pool by 2010 and 2% renewable fuel content in diesel and heating oil by 2012, upon successful demonstration of renewable diesel fuel use under the range of Canadian conditions. The content of renewable fuel in gasoline and diesel is regulated by different provincial legislation; therefore, some variations exist from province to province. This leads to differences in regulations on biofuels content in petrol and diesel within Canada, creating an avoidable patchwork in the Canadian fuel landscape.

25. *Deploying Renewables: Principles for Effective Policies*, IEA Paris, 2008.

RECOMMENDATIONS

The government of Canada should:

- *Develop a long-term policy for the future of renewable energy in Canada, integrating it into an overall energy strategy. This strategy must take into account the geographic, geological and resource differences between the provinces and territories.*
- *Remove and overcome, to the greatest extent possible, non-economic barriers as a first priority to improve policy and market functioning while having regard to Canada's unique national circumstances.*
- *Commit to the long-term, effective and predictable support mechanisms in order to provide developers and investors with a stable regulatory framework.*
- *Work with the provinces to harmonise regulations governing the content of renewable fuel in gasoline and diesel.*
- *Develop more ambitious programmes to facilitate the use of renewable electricity generation, micro-generation and heating in geographically isolated regions in order to offer an alternative to the consumption of petroleum products.*

COAL

OVERVIEW

In 2008, coal accounted for 9.6% of Canada's total primary energy supply (TPES). Canada produced 48.4 million tonnes of coal equivalent (Mtce) in 2008, of which 28.31 Mtce was hard coal (mostly coking and some steam) and 20.07 Mtce was brown coal (sub-bituminous and lignite).[26] There are 22 coal mines in operation at present and two idled. There are 21 coal-fired electricity generation plants located across six provinces. The sector directly employs a workforce in excess of 5 000 and is the largest user by tonnage of both the rail system and the ports. Two-thirds of consumption is met by domestic production and the remainder imported, largely from the United States. Canada exports most of its coking coal and is one of the world's major coking coal suppliers, third only to Australia and the United States.

SUPPLY AND DEMAND

SUPPLY

Canada's coal production has been relatively steady since 2000, particularly of brown coal (Figure 13). This is largely due to long-term supply agreements between producing mines and nearby electric generation plants, which account for almost 90% of Canada's coal consumption. Coking coal production has experienced production fluctuations in response to changing export demand.

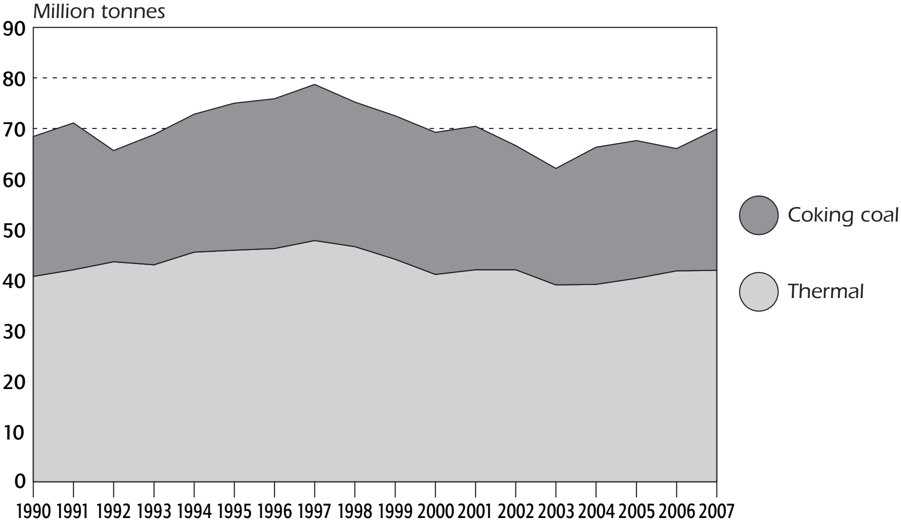
There were 22 coal mines operating in Canada at the end of 2008. British Columbia and Alberta hosted 17 of these and were the two highest producing provinces, together accounting for more than 80% of Canada's coal production.

Canada's integrated iron and steel mills, located primarily in Ontario, that use coking coal are a long distance from the major domestic deposits in western Canada, so most of Canada's coking coal is exported. Almost all of its brown coal production (all of Saskatchewan's, New Brunswick's and Nova Scotia's and most of Alberta's) is consumed domestically for coal-fired power generation. Brown coal production is expected to remain stable in the short and medium term. Coking coal and export steam coal are expected to increase to about 25 Mtce in the short to medium term, largely driven by growing worldwide demand.

26. *Coal Information 2009*, IEA/OECD Paris, 2009.

Figure 13

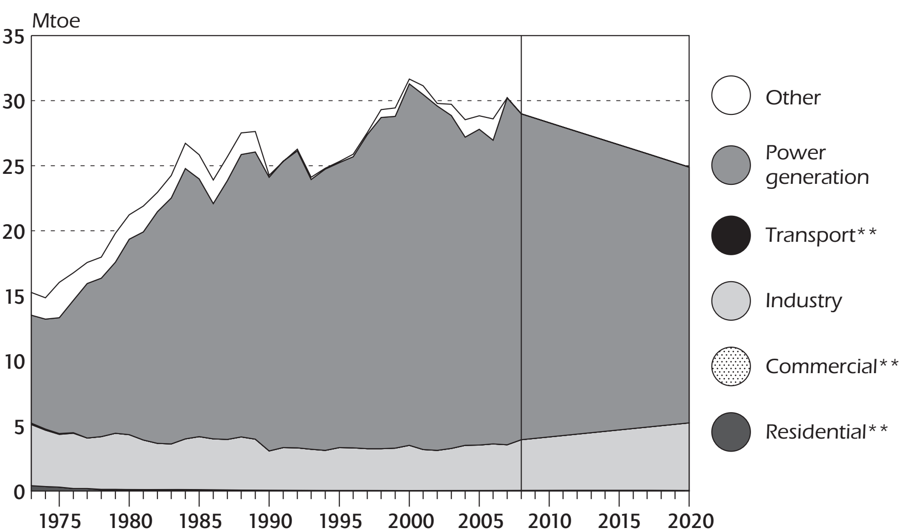
Coal Production, 1990 to 2007



Source: NRCan.

Figure 14

Coal Supply by Sector*, 1973 to 2020



* total primary energy supply by consuming sector. Other includes other transformation and energy sector consumption. Industry includes non-energy use. Commercial includes commercial, public services, agriculture, forestry, fishing and other final consumption.
** negligible.
Sources: *Energy Balances of OECD Countries*, IEA/OECD Paris, 2009 and country submission.

DEMAND

In 2007, coal accounted for 76% of all fuels consumed to generate electricity in Canada. Canada's coal consumption in 2007 was 43 Mtce, of which 38 Mtce, or 87%, was used in electricity generation at Canada's 21 coal-fired power plants (Table 8). Most of the remaining volumes were consumed in iron and steel production and other heavy industries. However, coal use in the iron and steel industry, including coke manufacture, fell from 6.9 Mtce in 1980 to 4.1 Mtce in 2007. The coal used in these industries is mainly imported from the United States. Coal's local availability and relatively low cost makes it the fuel of choice for electricity production in some provinces. Coal is used to produce about 50% of the electricity used in Alberta, 63% in Saskatchewan, 60% in Nova Scotia, and 18% in Ontario.

In Alberta, Sherritt and the Ontario Teachers' Pension Plan applied for an environmental assessment for the Dodds-Roundhill coal gasification project in early January 2007. If built, the project would be the first commercial application of coal gasification technology in Canada and would have a design capacity of 320 million cubic feet per day. There is however uncertainty as to whether or not this project will proceed.

In Saskatchewan, the provincial Crown utility, SaskPower, has announced a CAD 1.4 billion retrofit investment of Boundary Dam Generation Station Unit Three. The retrofit will introduce post-combustion capture of carbon dioxide flue gas emissions on a 100 MW (150 gross MW) unit. The captured carbon dioxide is to be delivered by pipeline for enhanced oil recovery within nearby oilfields, and subsequently for deep storage within oilfields or saline aquifers. A technology decision on carbon capture technology is expected in early 2010, with a final investment decision by mid-2010, and expected operation of the plant by 2015.

POWER PLANT EFFICIENCY

In 2007, the average thermal efficiency at Canada's coal-fired power plants was 31.3% (on a higher heating value, HHV, net electrical output basis).[27] This represents a negligible decrease from the 2006 efficiency level of 31.4%. Efficiencies are generally lower in Alberta and Saskatchewan owing to the greater use of sub-bituminous coal (in Alberta) and lignite (in Saskatchewan). In 2005, Genesee 3, the first facility in Canada to use supercritical boiler technology, was commissioned near Edmonton, Alberta. It has a thermal efficiency of approximately 39%.

27. Source: *Electric Power Generation, Transmission and Distribution 2007*, Table 6-2, Statistics Canada.

Table 8

Coal-Fired Power Plants in Canada, 2009

Plant name	*Location*	*Owner*	*Capacity, MW_e*	*Units, MW_e (commissioned)*	*Fuel (source)*	*Pollution control*
Atikokan	Atikokan, Ontario	Ontario Power Generation Inc	215	1 x 215 (1985)	lignite (domestic)	LNB (1985) *to be closed by end of 2014*
Battle River	Forestburg, Alberta	ATCO Power Ltd	664	1 x 148 (1969) 1 x 148 (1975) 1 x 368 (1981)	sub-bituminous (domestic)	
Belledune	Bathurst, New Brunswick	New Brunswick Power Corp	475	1 x 475 (1993)	bituminous (domestic & imported)	FGD (1993)
Boundary Dam	Estevan, Saskatchewan	SaskPower	814	2 x 62 (1959/60) 3 x 139 (1969-73) 1 x 273 (1978)	lignite (domestic)	
Brandon	Brandon, Manitoba	Manitoba Hydro-Electric Board	105	1 x 105 (1970)	sub-bituminous (USA)	
Genesee	Warburg, Alberta	Capital Power Corp	768	2 x 384 (1989-94)	sub-bituminous (domestic)	FGD/LNB (2005)
Genesee 3	Warburg, Alberta	Capital Power Corp/TransAlta Utilities Corp	450	1 x 450 (2005)	sub-bituminous (domestic)	FGD/LNB (2005)
Grand Lake 2	Minto, New Brunswick	New Brunswick Power Corp	60	1 x 60 (1964)	bituminous (domestic)	*closes June 2010*
Keephills	Wabamun, Alberta	Capital Power Corp/TransAlta Utilities Corp	762	2 x 381 (1983/84)	sub-bituminous (domestic)	OFA
Keephills 3	Wabamun, Alberta	Edmonton Power Inc EPCOR/TransAlta Utilities Corp	450	1 x 450 (2011) under construction	sub-bituminous (domestic)	FGD/LNB (2011)
Lambton	Courtright, St. Clair Township, Ontario	Ontario Power Generation Inc	1 976	4 x 494 (1969/70)	bituminous (USA)	LNB (1993-2000) on all units FGD (1994) on 2 units SCR (2002/03) on 2 units *Two non-scrubbed units to close in October 2010; remainder to be closed by end of 2014*
Lingan	New Waterford, Cape Breton Island, Nova Scotia	Nova Scotia Power Inc	620	4 x 155 (1979-84)	bituminous (domestic)	
H R Milner	Grande Cache, Alberta	Maxim Power Corp	143	1 x 143 (1972)	bituminous (domestic)	

Table 8

Coal-Fired Power Plants in Canada, 2009 *(continued)*

Plant name	*Location*	*Owner*	*Capacity, MW_e*	*Units, MW_e (commissioned)*	*Fuel (source)*	*Pollution control*
Nanticoke	Nanticoke, Ontario	Ontario Power Generation Inc	3 920	8 x 490 (1973-78)	sub-bituminous/bituminous (USA)	LNB (1997-2000) on all unts OFA (2002) on 1 unit SCR (2003) on 2 units *Two non-scrubbed units to close in October 2010; remainder to be closed by end of 2014*
Point Aconi	Sydney Mines, Cape Breton Island, Nova Scotia	Nova Scotia Power Inc	171	1 x 171 (1995)	bituminous (domestic & imported)	CFBC
Point Tupper	Port Hawksbury, Cape Breton Island, Nova Scotia	Nova Scotia Power Inc	154	1 x 150 (1987)	bituminous (domestic & imported)	
Poplar River	Coronach, Saskatchewan	SaskPower	572	1 x 291 (1981) 1 x 281 (1983)	lignite (domestic)	
Shand	Estevan, Saskatchewan	SaskPower	279	1 x 279 (1992)	lignite (domestic)	LI (1992)
Sheerness	Hanna, Alberta	ATCO Power Ltd. / TransAlta Cogeneration LP	760	2 x 380 (1986-90)	bituminous (domestic)	
Sundance	Seba Beach, Alberta	TransAlta Utilities Corp	2 124	2 x 280 (1970-73) 1 x 353 (1976-78) 2 x 406 (1977-78) 1 x 399 (1980)	sub-bituminous (domestic)	OFA OFA OFA OFA
Thunder Bay	Thunder Bay, Ontario	Ontario Power Generation Inc	306	2 x 153 (1981/82)	lignite/sub-bituminous (domestic/USA)	*to be closed by end of 2014*
Trenton	New Glasgow, Nova Scotia	Nova Scotia Power Inc	307	1 x 150 (1969) 1 x 157 (1991)	bituminous (domestic & imported)	
Wabamun	Wabamun, Alberta	TransAlta Utilities Corp	279	1 x 279 (1968)	sub-bituminous/bituminous (domestic)	*closes March 2010*
Total			**16 374**	**(450 MWe under construction)**		

Notes: CFBC – circulating fluidised bed combustor (in-bed sulphur removal); FGD – flue gas desulphurisation; LI – limestone injection into the furnace to reduce SO_2; LNB – low-NO_x burners; OFA – over-fire air (reduces NO_x). Sources: CoalPower5 database, IEA Clean Coal Centre and company reports.

Figure 15

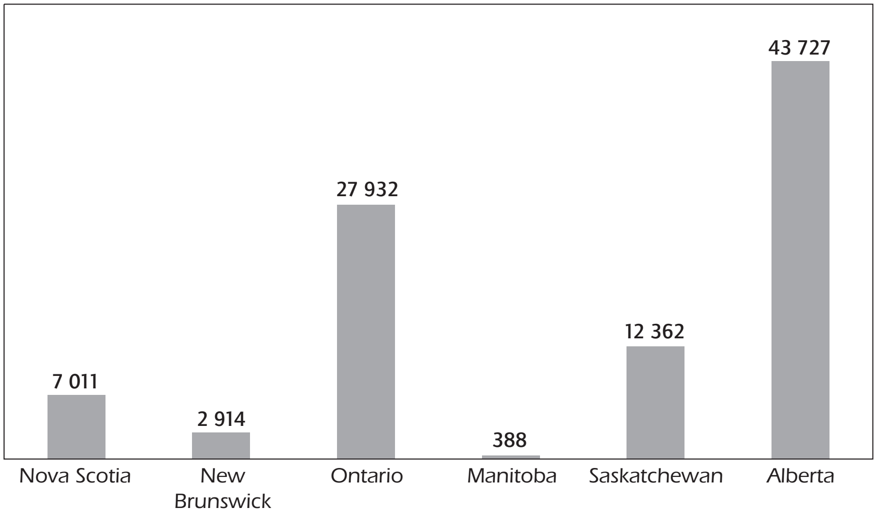
Coal Deposits and Infrastructure of Western Canada

The boundaries and names shown and the designations used on maps included in this publication do not imply official endorsement or acceptance by the IEA.

Source: *Major Coalfields of the World*, IEA Coal Research 2002, London.

Figure 16

Net Coal-Fired Generation, 2007 (GWh)



Source: *Electric Power Generation, Transmission and Distribution 2007*, Table 6-2, Statistics Canada.

Keephills 3, a 450 MW power plant using the same supercritical pulverised coal combustion technology as Genesee 3, is currently under construction and is expected to be commissioned in early 2011 in Alberta. Point Aconi (171 MW), Nova Scotia is the only commercial fluidised bed power plant in Canada. Most coal-fired power plants in Canada are subcritical designs more than 25 years old. While efficiencies are improving as more supercritical units come on line, NRCan is exploring the potential to improve efficiencies at the older plants.

Ontario Power Generation has tested renewable biomass fuels (*e.g.* wood pellets) at some coal-fired units. By 2014, the company plans to phase out its use of coal, putting the province on track to be one of the first jurisdictions in the world to eliminate coal-fired electricity generation.

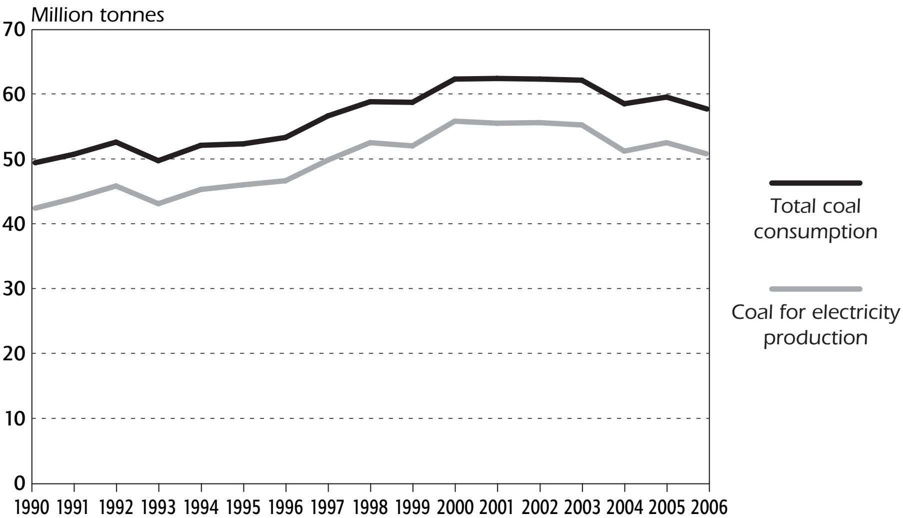
RESERVES

Canada has 8.7 billion tonnes of proven coal reserves (NRCan, 2009). Approximately 6.6 billion tonnes are considered economically viable and recoverable using existing technology. British Columbia, Alberta and Saskatchewan coal mines are developing and operating in the largest known coal reserves in Canada (*ibid.*). A small amount of coal is also mined in Nova Scotia and New Brunswick. Undeveloped coal reserves have been documented in Yukon, Ontario, Newfoundland and Labrador, Northwest Territories and Nunavut.

Geological reserves of coal exceed proven reserves in Canada and estimates suggest there is a further 193 billion tonnes of coal-in-place (*ibid.*). This estimate includes unexplored extensions of known deposits, undiscovered reserves in known coal-bearing sediments, as well as reserves inferred from favourable geological conditions.

Figure 17

Coal Consumption, 1990 to 2006



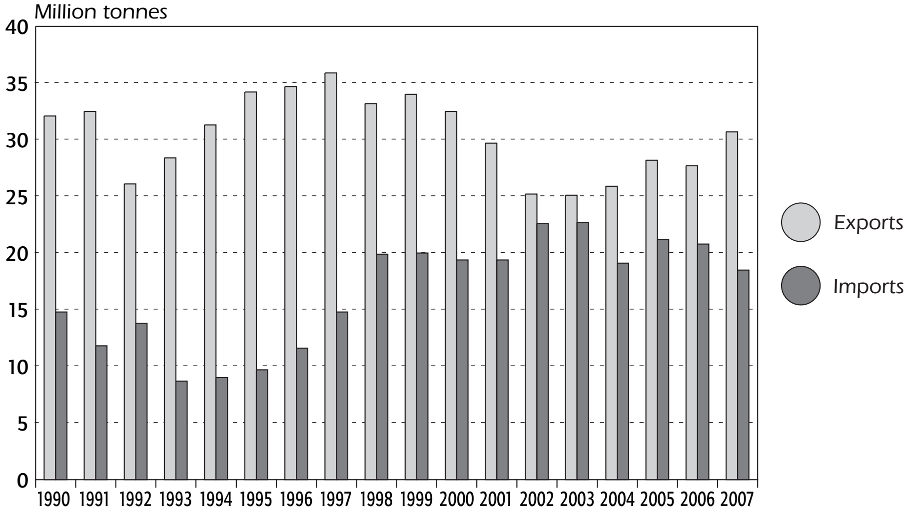
Source: NRCan.

IMPORTS AND EXPORTS

Canada is a net exporter of coal, with more than 48% of production exported by volume in 2008. On an energy basis, Canada exported 27.89 Mtce of coal in 2008, of which 81% was coking coal. Canada exports coal to a large number of countries, much of it going to Japan and Korea. In 2008, exports to Korea and Japan accounted for 53% of Canada's total coal exports by volume. Other significant export markets are the European Union (EU), the United States and Brazil. In 2009, coking coal exports to China rose steeply, compensating to some extent the decline in demand from other countries following the global economic crisis. Canadian coal exports are mainly from Teck Resources Limited's five coal mines in British Columbia, and one mine in Alberta. About 90% of exports were shipped by sea through coal terminals in Vancouver (Ridley terminal) or Prince Rupert, both located in British Columbia, and through the port of Thunder Bay, Ontario. In addition, small amounts were transported by rail to the United States.

Figure 18

Coal Trade, 1990 to 2007



Source: IEA.

Canada's coal exports are expected to increase to 28-30 Mtce in the mid-term largely driven by the increased global demand for coking coal. Coking coal demand has shown strength in 2009 and international demand is expected to remain strong. Steam coal exports from Canada are not expected to increase significantly. A limited number of coal mines produce bituminous grade thermal coal suitable for exports and the majority of coal mines produce sub-bituminous and lignite coal which are of lower energy content and not in demand on global markets.

Coal is imported into central and eastern Canada from the eastern United States which has a competitive transportation advantage over coal produced from more distant western Canada. In 2008, Canada imported 17.1 Mtce of coal, largely for electricity generation in Ontario and the Atlantic provinces. The majority of imports, or 87% by volume, came from the United States, 12% from Colombia and the remainder from Russia and several other countries. Coal imports to Ontario are gradually declining, mainly owing to the policy of phasing-out coal-fired power generation plants in the province – postponed to 2014 because of increases in electricity demand.

POLICIES

MINERALS AND METALS POLICY

The largest share of mineral resources, including coal, are provincially owned while those located offshore and north of 60° latitude are owned by the federal government. Privately owned onshore mineral resources are subject to provincial resource management authority. The Minerals and Metals Policy of the government of Canada was published in 1996 and describes, within areas of federal jurisdiction, the government's role, objectives and strategies for the sustainable development of Canada's mineral and metal resources.

The policy was developed after extensive consultations involving federal departments and agencies, provincial and territorial mines ministries, industry, environmental groups, labour, and aboriginal communities. The policy affirms provincial jurisdiction over mining, and delineates a role for the federal government in minerals and metals mine development that is tied to federal responsibilities, and commits the government to pursue partnerships with stakeholders when addressing issues within its jurisdiction. It also promotes partnerships between federal government and the provinces and territories for sustainable mining initiatives. The policy also promotes aboriginal participation in minerals and metals mining activities throughout Canada.

More recently, the ecoENERGY Technology Initiative 2007 is a government programme that has been developed to accelerate technological solutions for clean energy. This includes clean coal technology and carbon capture and storage. The programme's goal is to advance the development of technology and improve the efficiency of coal-fired generation plants in order to minimise the negative environmental impacts normally associated with the use of coal.

ENVIRONMENTAL POLICY

Federal and provincial/territorial environmental law impacts existing and new coal mine development through regulation intended to protect the environment and public safety.

The Clean Air Regulatory Agenda is the cornerstone of the federal government's broader efforts to address the challenges of climate change and air pollution. In October 2006, the government published a *Notice of Intent* to regulate air emissions, which provides the basis for the Clean Air Regulatory Agenda. The framework establishes emissions reduction targets for given air pollutants and will specify a maximum level of each pollutant that can be emitted from a given sector in a given year. The targets are proposed to come into effect as early as possible between 2012 and 2015 to give industry time to make the necessary investments in plant and equipment or processes.

Fixed emission caps would be set for the following air pollutants: nitrogen oxides (NO_x), sulphur oxides (SO_x), volatile organic compounds (VOCs), and particulate matter (PM). The industrial regulations will concern facilities in the electricity generation, smelting and refining, iron and steel, some mining and cement, lime, and chemicals sectors.

Table 9

Allowable Pollutant Emissions from Power Plants in Canada

	2006 estimated emissions (tonnes)	*2015 projected emissions (tonnes)*	*2015 emissions target (with reduction) (tonnes)*	*% change in 2015 from 2006 with target*	*Basis for target or jurisdiction*
Oxides of nitrogen (No_x)	258 00	267 000	105 000	–59%	United States
Sulphur dioxide (SO_2)	518 000	489 000	206 000	–60%	United States
Particulate matter (PM)	33 000	35 000	15 000	–55%	United States
Mercury (Hg)	2 073	–	1 078	–48%	United States Clean Air Mercury Rules

Source: *Clean Air Regulatory Agenda – Regulatory Framework for Industrial Air Emissions, In-depth Technical Briefing*, Environment Canada, April & May 2007.

According to the Clean Air Regulatory Agenda, for existing facilities, the greenhouse gas emission-intensity reduction target for each sector would be based on an improvement of 6% each year from 2007 to 2010. This yields an initial enforceable reduction in 2010 of 18% below 2006 emission-intensity levels. Every year thereafter, a 2% continuous emission-intensity improvement will be required, resulting in an industrial emission-intensity reduction of 26% by 2015. Targets for new facilities will be established on the basis of cleaner fuel standards. These targets could result in absolute reductions in GHG emissions from industry as early as 2010 and no later than 2012. However, the application of these proposals is under review, and could be subject to change.

The enactment of the Canadian Environmental Assessment Act in 1995 established sustainable development as a fundamental objective of the federal environmental assessment process. The Canadian Environmental Assessment Agency, accountable to Parliament through the Minister of the Environment, administers the federal environmental assessment process. Generally, all proposals for new mines must undergo an environmental impact assessment, which must be reviewed and approved by both the provincial and federal authorities. Subsequently, all mining activities must minimise the negative environmental effects and all sites must be reclaimed and rehabilitated by the operator.

In addition, there are an estimated 27 000 orphaned or abandoned mines in Canada.[28] Some of these sites pose environmental, health and safety concerns to nearby communities and subsequently create economic problems as well as opportunities for these communities. Solutions for addressing these

28. Source: NRCan.

issues are a priority for the federal and provincial governments as well as for the mining industry. The federal government's Sustainable Development through Knowledge Integration (SDKI) project for Sustainable Management and Rehabilitation of Mine Sites for Decision Support is a mechanism that engages collaboratively with federal departments, provincial and territorial governments and industry to develop new techniques for information collection and integration to support mine reclamation and policy decisions surrounding mine rehabilitation. The project's priorities are to:

- collaborate with decision makers and stakeholders to ensure the development of relevant spatial information products;
- develop spatial tools to support a national inventory of orphaned/abandoned mines in Canada;
- facilitate long-term monitoring, assessment and rehabilitation of acid-generating tailings and waste rock disposal areas through effective implementation of spatial tools;
- facilitate the assessment and modelling of socio-economic and environmental impacts of mine wastes through the development of data and information integration techniques.

The Canadian Environmental Protection Act, 1999 is the primary legislation that regulates mercury and other toxic substances. In Canada, mercury releases can typically be attributed to waste incineration, coal combustion, base metal smelting, and the chloralkali industry. In 2007, coal-fired electricity generation was responsible for 29% of Canadian mercury emissions.[29] Pilot tests undertaken at TransAlta's Sundance 5 (one of the largest emitters of mercury) and Keephills 2 units in Alberta between 2006 and 2008 showed that capture technologies could viably recover 60% to 70% of the mercury in the coal.

INDUSTRY STRUCTURE

At the end of 2008, 22 coal mines were in operation in Canada, of which 20 are opencast and two are underground mines. Coal consumers comprise 21 coal-fired power generation plants, iron and steel producers, cement and other industrial users. The service providers include railways, ports, equipment suppliers, and exploration and engineering service firms. Twenty-one mines are owned or jointly owned by eight publicly traded companies. One is operated by a private entity. There are no government-owned coal mines in Canada.

Of the 22 mines, nine produce metallurgical (coking) coal for exports; one produces pulverised coal injection (PCI) coal for export; four produce bituminous steam coal, two for exports and two for domestic coal-fired power generation; five produce sub-bituminous coal and three produce lignite coal. Both sub-bituminous and lignite coals are used for domestic coal-fired power generation (Table 10).

29. Source: 2007 National Pollutant Release Inventory, Environment Canada.

Table 10

Coal Mines in Canada

Product	Market	Coal Mine	Capacity (Mt/y)		Location	Owner	Operator
			Mine	Plant			
Coking coal	Export	Cheviot	2	3	Hinton, Alberta	Teck Resources Limited	Teck Coal
Coking coal	Export	Coal Mountain	2.7	3.5	Sparwood, British Columbia	Teck Resources Limited	Teck Coal
Coking coal	Export	Elkview	5.6	6.5	Sparwood, British Columbia	Teck Resources Limited	Teck Coal
Coking coal	Export	Fording River	8.3	10	Elkford, British Columbia	Teck Resources Limited	Teck Coal
Coking coal	Export	Greenhills	4.5	4.5	Elkford, British Columbia	Teck Resources Limited	Teck Coal
Coking coal	Export	Line Creek	2.2	3.5	Sparwood, British Columbia	Teck Resources Limited	Teck Coal
Coking coal	Export	Wolverine	2.2	3	Chetwynd, British Columbia	Western Coal Corporation	WCC
Coking coal	Export	Trend	2	2	Tumbler Ridge, British Columbia	Peace River Coal Inc.[1]	PRC
Coking coal	Export	Grande Cache	2	2	Grande Cache, Alberta	Grande Cache Coal Corporation	GCC
PCI coal	Export	Brule	1.2	1.2	Tumbler Ridge, British Columbia	Western Coal Corporation	WCC
Bituminous steam	Export	Coal Valley	3.8	3.8	Edson, Alberta	Sherritt International Corporation and Ontario Teachers' Pension Plan	Sherritt
Bituminous steam	Export	Quinsam	0.5	0.5	Campbell River, British Columbia	Hillsborough Resources Limited	Hillsborough
Sub-bituminous	Domestic	Genesee	5.6		Warburg, Alberta	Sherritt International Corporation and EPCOR	Sherritt
Sub-bituminous	Domestic	Highvale	13		Seba Beach, Alberta	TransAlta Corporation	Sherritt
Sub-bituminous	Domestic	Paintearth[2]	3.5		Forestburg, Alberta	Sherritt International Corporation	Sherritt
Sub-bituminous	Domestic	Sheerness	4		Hanna, Alberta	Sherritt International Corporation	Sherritt
Sub-bituminous	Domestic	Whitewood	2.8		Seba Beach, Alberta	TransAlta Corporation	Sherritt
Lignite	Domestic	Poplar River	4		Coronach, Saskatchewan	Sherritt International Corporation	Sherritt
Lignite	Domestic	Bienfait	2.8		Bienfait, Saskatchewan	Sherritt International Corporation	Sherritt
Lignite	Domestic	Boundary Dam	6.5		Estevan, Saskatchewan	Sherritt International Corporation	Sherritt
Bituminous steam	Domestic	Salmon Harbour			Minto, New Brunswick	NB Power	NB Coal
Bituminous steam	Domestic	Stellarton			Stellarton, Nova Scotia	Pioneer Coal Limited	Pioneer
Bituminous steam	Export	Obed	1.2	n/a	Hinton, Alberta	Sherritt International Corporation	Sherritt

1. Peace River Coal Inc. - A partnership between Anglo Coal Canada Inc. (74.51%), Northern Energy and Mining Inc. (13.36%), and Hillsborough Resource Ltd. (12.13%.
2. Capacity includes nearby Vesta mines.

Abbreviations: Teck - Teck Resources Limited; Teck Coal - Teck Coal Limited; WCC - Western Canadian Coal Corporation; PRC - Peace River Coal Inc.; GCC - Grande Cache Coal Corporation; Sherritt - Sherritt International Corporation; Hillsborough - Hillsborough Resources Limited; TransAlta - TransAlta Corporation; Pioneer - Pioneer Coal Limited; Dodds - Dodds Coal Mining Company Ltd.; Alberta - Alberta Power Company Ltd.; n/a - not available

Source: Natural Resources Canada.

The Herman coal mine project in British Columbia and the Donkin underground exploration project in Nova Scotia received environmental assessment approvals in 2008. At Donkin, the coal seam extends out under federal sea waters.

On 13 November 2007, the Canadian Parliament passed the Donkin Coal Block Development Opportunity Act to pave the way for development of the mine, now owned by Xstrata (75%) and Erdene Gold (25%).

Six other projects await environmental assessment approval from the BC government: Roman coal mine (coking) by Peace River Coal Inc. (PRC); Gething project (coking) by Dehua International Mines Group Inc.; Lodgepole mine (coking) by Cline Mining Corp.; Horizon mine (coking) by PRC; Mount Klappan project (anthracite) by Fortune Minerals Ltd.; and Raven project (coking and thermal) by Compliance Coal Corporation.

PRICING

There are no market prices available for steam coal in Canada nor are there coal production or consumption subsidies. This unavailability of pricing data is largely owed to the presence of long-term contracts between coal producers and most large coal consumers. Coal producers report realised prices which reflect the cost of producing coal. Coking coal and export steam coal prices are settled annually according to negotiations between coal producers-exporters and their customers in importing countries. For example, Canada's coking coal export price averaged USD 300 per tonne on the basis of all of the contract settlements for 2008/09 coal year.

OUTLOOK

Canada is the world's third-largest coking coal supplier. Its coking coal production and exports will benefit from the growing global demand for coking coal in the short to medium term, as global demand is forecast to increase significantly. Long-term growth will depend on the global economy and steel industry development because Canada's coking coal is export-oriented. Steam coal production is expected to be stable.

Canada's coal consumption is expected to decline in the longer term as a result of measures to reduce GHG emissions. The development and implementation of new technologies such as carbon capture and storage and clean coal could, however, help sustain the use of coal for electricity generation in the future.

CRITIQUE

Canada's coal reserves are abundant, constituting by far the largest hydrocarbon reserves in a resource-rich country. Steam coal production has been relatively stable in recent years but coking coal production has been on a rising trend since 2003 and has the potential to grow further, depending on trends in the global steel industry. Accounting for just over 10% of global coking coal exports, Canada's coal exports add an important element of competition to what is otherwise a relatively concentrated market by providing an alternate source of coking coal for consumers around the world.

There are some signs of increasing difficulty and delay in obtaining consent for new mines. In this respect the establishment by the federal government of the Major Projects Management Office, tasked with streamlining approval procedures, is a welcome development.

Access to competitive rail transport and port facilities is also important. At present these appear adequate, especially during the current downturn, but their availability needs to be kept under review to ensure that transportation bottlenecks do not restrict future growth. The Ridley Terminal in British Columbia is a key facility and the federal government will give careful consideration to access issues if, as has been proposed, the Ridley Terminal is sold.

The federal government faces major challenges in demonstrating that coal mining can be regulated effectively and managed in an environmentally sound manner. This will be achieved through the adoption of legislation and regulation that minimise the negative effects on the environment.

Coal-fired power generation accounted for more than 13% of Canada's CO_2 emissions in 2007, making this sector one of the largest emitters of CO_2 in the country (after the transport sector). This, comparatively speaking, has a much greater impact than current oil-sands production and development and it is expected that coal-fired power generation will remain a leading CO_2 emissions producer for at least the next decade. The decision of Ontario to phase out its coal-fired power generation will, therefore, make a significant contribution to CO_2 savings, provided that the capacity is replaced through energy efficiency improvements or cleaner power sources. To replace the loss of coal-fired power generating capacity as well as to meet any increase in demand, Ontario plans to more than double renewable capacity to 15.7 GW and secure 5.6 GW of increased energy efficiency, all by 2025. These are tough targets and the risk, if they cannot be met, is that the increase in gas–fired generation may be even greater than the planned 4.5 GW.

Much of Canada's coal-fired power generation fleet is more than 25 years old and its average efficiency, at 31%, is relatively low. Canada's first supercritical coal-fired power plant was commissioned in Alberta in 2005. Coal-fired power generation, especially those units of high efficiency, are expected to be amenable to carbon capture and storage (CCS) and the major steps that the federal government and the provinces of Alberta and Saskatchewan are taking to develop and demonstrate this technology are welcome.

Under the 2007 Federal Regulatory Framework for Air Emissions, each power generation company is required to achieve an 18% reduction in GHG emission intensity by 2010, with further 2% per year reductions thereafter. A number of alternative compliance options are offered in the legislation. Nevertheless, this may provide an incentive for the retirement, upgrading and replacement of less efficient plants. Under the *Turning the Corner* proposals put forward by the federal government in March 2008, from 2012 all new coal-fired plants would have been required to meet CCS regulatory standards. However, we understand that the application of these proposals is under review, and this means that there is currently no clear regulatory signal to the power industry that CCS will be required.

RECOMMENDATIONS

The government of Canada should:

- *Continue its efforts through the Major Projects Management Office to streamline the approval process for new mines.*
- *Through sound regulatory practice, continue to demonstrate that coal mining can be effectively regulated and managed in an environmentally acceptable way.*
- *Along with provincial authorities, keep under review the availability of competitive rail transport and port facilities to avoid bottlenecks in the future development of the coal industry.*
- *Complement its efforts to develop and demonstrate CCS with clear regulatory and economic signals to the coal power industry on the need to close, upgrade or replace inefficient plants, and to adopt CCS as soon as this technology becomes commercially available.*

CARBON CAPTURE AND STORAGE

OVERVIEW

Carbon capture and storage (CCS) is a priority for the government of Canada. Western Canada in particular represents a world-class opportunity to advance CCS, with a concentration of large final emitters (*e.g.* oil-sands and coal-based power generation) in close proximity to excellent storage sites. Depleted oil and gas reservoirs in this region, whose location and geology are well-researched, are the most promising storage sites, with an estimated capacity of 3 800 Mt CO_2-eq. Unminable coal beds and deep saline aquifers have potentially much greater capacity but require additional research. The Weyburn-Midale CO_2 Enhanced Oil Recovery (EOR) project in Saskatchewan is one of the largest CCS projects in the world. It is also the site of the world's first measuring, monitoring and verification initiative, which is supported by industry and governments and endorsed by the International Energy Agency's GHG Research and Development Programme.

At present, CCS is the only technology available to mitigate greenhouse gas (GHG) emissions from large-scale fossil fuel usage in fuel transformation, industry and power generation. CO_2 capture technologies have long been used by industry to remove CO_2 from gas streams where it is not wanted or to separate CO_2 as a product gas. CO_2 storage involves the injection of CO_2 into a geologic formation to enhance carbon recovery. The three options for geological CO_2 storage are saline formations, oil and gas reservoirs, and deep unminable coal seams. The practices in respect to CO_2 injection are well known; however, more experience is needed to improve predictions of CO_2 behaviour at commercial scale. Exploration programmes are also needed to locate and characterise suitable storage sites, particularly deep saline formations.

POLICY FRAMEWORK AND FUNDING

Previously, the federal government announced a national objective to reduce emissions by 20% below 2006 levels by 2020, and by 60% to 70% by 2050. More recently, in January 2010, the federal government announced the submission of its 2020 emissions reduction target under the Copenhagen Accord: an economy-wide 17% reduction from 2005 levels. These targets present a great challenge to a country highly reliant on fossil fuels for a large part of its primary energy supply and export revenues. CCS presents Canada with an opportunity to develop a technology that can reduce GHG emissions on a large scale and the federal government acknowledges that it could form a large part of Canada's overall plan to reduce emissions. Given the high costs and uncertainties associated with CCS, GHG policies and/or carbon prices alone will not progress this technology. Canada and other countries need therefore to look at an integrated policy that brings the technology from large-scale demonstration to commercialisation through economic and/or regulatory incentives.

Similar to other federal countries, such as Australia and the United States, the regulation of CCS in Canada involves a complex interaction between federal and provincial laws and policies. Various measures to encourage or mandate GHG mitigation, including via CCS, also exist or are being developed at provincial level. In Alberta, the provincial government anticipates that CCS will account for 70% of its intended emissions reductions of 14% below 2005 levels by 2050.[30] Saskatchewan's climate change policy framework provides for enhanced oil recovery (EOR) with a view to developing a market for clean coal. As with other aspects of climate change policy, further work will need to be undertaken by the federal and provincial governments to ensure consistency and compatibility of any CCS-related obligations on industrial entities.

Existing federal and provincial oil and gas legislation covers certain aspects of CCS, including CO_2 capture and transportation-related issues, such as construction and health and safety issues. In most Canadian jurisdictions, CO_2 storage activities, in particular property rights (storage and access rights) and post-injection activities (regulatory permitting, monitoring requirements and long-term liability) still remain to be addressed. At present there is no provincial or federal legislation specifically dealing with the permanent storage of CO_2, though excellent analogues exist in provincial oil and gas regulatory frameworks (for example those governing EOR, natural gas storage and acid gas disposal activities). The majority of these outstanding regulatory issues fall under provincial jurisdiction, though the federal government has a role in climate change-related aspects and potentially in the environmental assessment of CCS projects.

In January 2008, the Canada-Alberta ecoENERGY CCS Task Force recommended that existing legislation governing oil, gas and water activities be extended to address CO_2 storage property rights.[31] The Task Force also recommended that CCS regulatory authority be vested in the existing oil and gas regulatory agencies, as they have significant knowledge and infrastructure in place for regulating similar subsurface activities such

30. *Accelerating Carbon Capture and Storage Implementation in Alberta*, Alberta Carbon Capture and Storage Development Council Final Report, March 2009.
31. *Canada's Fossil Energy Future - The Way Forward on Carbon Capture and Storage*, the ecoENERGY Carbon Capture and Storage Task Force, January 2008.

as oil and gas production, natural gas storage, and acid gas and deep waste disposal. More specifically in March 2009, the Alberta CCS Development Council recommended that issues of pore space tenure and long-term storage liability be addressed in the near term to ensure the first wave of CCS demonstration projects have regulatory certainty.

FUNDING FOR CCS DEMONSTRATION PROJECTS

The federal government and several provinces are taking steps to promote CCS technology. The government of Canada has committed just over CAD 1.0 billion in funding for CCS towards large-scale CCS demonstration projects through various programmes, including the CAD 650 million Clean Energy Fund, the CAD 240 million in funding for Saskatchewan's Boundary Dam clean coal initiative, as well as the CAD 151 million ecoENERGY Technology Initiative that supports pre-demonstration CCS activities (*e.g.* front-end engineering design studies) and small-scale demonstrations.

The Alberta government has announced that four projects will receive funding under their CAD 2 billion fund to accelerate the development of the province's first large-scale, commercial carbon capture and storage projects. This includes two oil-sands-related projects (Shell Canada Energy, Enhance Energy), one post-combustion coal-fired power project (TransAlta), and an *in situ* coal gasification project (Swan Hills). These projects are expected to yield reductions of 5 Mt CO_2 per year from 2015. The governments of Saskatchewan and British Columbia have also allocated funding towards pilot or large-scale CCS projects.

The next important step for both federal government and the governments of the provinces is to commit funding to the implementation of projects and advance their construction.

CO_2 STORAGE POTENTIAL

Canada's most promising CO_2 storage potential is located primarily in the Western Canadian Sedimentary Basin (WCSB), which is in close proximity to approximately half of Canada's large CO_2-emitting industrial facilities. Significant storage opportunities also exist in southern Ontario and on the east coast of Canada. Storage opportunities include using CO_2 in enhanced hydrocarbon recovery, as well as direct storage in deep saline formations, depleted or near-depleted oil and gas reservoirs, and unminable coal beds. The Alberta CCS Development Council – made up of government, industry and academic CCS experts – reported an estimate of at least three gigatonnes of total CO_2 storage in the province of Alberta alone. Research is under way to refine estimates of CO_2 storage potential for various parts of the country.

Figure 19

Locations of Canada's CO_2 Storage Potential

The boundaries and names shown and the designations used on maps included in this publication do not imply official endorsement or acceptance by the IEA.

Source: NRCan.

CCS INITIATIVES

CANADIAN CCS NETWORK

A government-based CCS Network, comprising the federal government and the governments of British Columbia, Alberta, Saskatchewan, Ontario, Québec, New Brunswick and Nova Scotia, was established in June 2009. The goal of this federal-provincial network is to facilitate the rapid implementation and deployment of CCS technology in Canada by enhancing information exchange and linkages between governments, and by promoting common strategic approaches to policy, regulatory, legal and technology issues. The network will further advance the understanding of and address the need for information on CCS, both by governments and the public at large, by becoming a single-access point for CCS information in Canada. To this end, the network is working with other stakeholders to establish a national CCS website in 2010. Finally, the network plans to organise annual Canadian CCS forums and other CCS conferences/events as deemed appropriate.

OTHER CARBON CAPTURE AND STORAGE INITIATIVES

A wide range of additional initiatives are under way to enhance the capture and storage of carbon dioxide in Canada:

- The government of Canada is a lead sponsor of the IEA's Weyburn-Midale CO_2 Monitoring and Storage Project. Now entering its second phase, this project is the world's first measuring, monitoring, and verification initiative for CCS, engaging over 30 different government, industry and research partners from around the world.
- The Integrated Carbon Dioxide Network (ICO_2N) is an industry consortium proposing a CCS system for Canada.[32] The participants represent a cross-section of Canadian industry seeking to accelerate the development of large-scale CCS in Canada.
- The Alberta Saline Aquifer Project (ASAP) is an industry initiative led by Enbridge to identify deep saline aquifers in Alberta that could be used in a carbon sequestration pilot project. ASAP's purpose is to: locate CO_2 storage sites along anticipated pipeline routes to enhanced oil recovery (EOR) projects; collect CO_2 from existing and future emissions locations; and develop the capability to simultaneously provide CO_2 to EOR projects and store excess CO_2 in saline aquifers. Enbridge will work collaboratively with EPCOR Utilities Inc. to provide transport and storage of the CO_2 captured (1 Mt or more per year) in its CCS projects.

32. *Carbon Dioxide Capture and Storage - A Canadian Clean Energy Opportunity*, Summary Report by the ICO_2N group of Companies, October 2009.

- The Wabamun Aquifer Storage Project, co-ordinated by the University of Calgary, will assess CO_2 storage in deep saline aquifers at sites in the vicinity of four major coal-fired power plants in central Alberta, west of Edmonton.
- Led by Alberta Research Council Energy Trust and the Alberta Research Council Inc., the Heartland Area Redwater Project will evaluate the potential for the Redwater Leduc reef complex (the third-largest oil reservoir in Canada) to store as much as 1 000 Mt CO_2. This could accommodate more than 20 years of CO_2 emissions from existing and planned facilities in the industrial Heartland area north-east of Edmonton, Alberta.
- The Petroleum Technology Alliance Canada co-ordinates the Carbon Capture Storage Project with 16 industry participants evaluating CO_2 sources in the Fort Saskatchewan area. The study considers CO_2 purification, dehydration and compression requirements to reveal the merits of economies of scale and process configurations for efficient CO_2 capture.
- The Shell-Quest project will capture CO_2 from the hydrogen units at Shell's Scotford upgrader near Edmonton. Two units are currently in operation, with a third one expected by 2011. Over 1 Mt of CO_2 will be captured, which will be transported for permanent storage in a deep saline aquifer. Project start-up is expected by 2015.
- Phase 1 of the SaskPower-Boundary Dam project will rebuild an existing generating unit at the Boundary Dam power plant. Initially, a new 100 MW unit will be added with a post-combustion capture system, for up to 1 Mt of CO_2 annually. The CO_2 will be transported to EOR projects such as Weyburn-Midale and subsequently for permanent storage. The project is expected to start operations in 2015.
- The TransAlta Pioneer project will construct the world's first large-scale CCS facility that integrates a competitive, leading-edge capture technology with a power plant using the chilled-ammonia process to capture 1 Mt of CO_2 per year; transport CO_2 to a permanent geological storage site and for use in enhanced oil recovery; prove safe, secure, large-scale permanent storage in saline aquifers; and deliver significant, real reductions in CO_2 emissions by 2012.
- The Enhance Alberta Carbon Trunkline will collect CO_2 from industrial emitters in and around Alberta's Industrial Heartland and transport it to ageing reservoirs throughout central and southern Alberta for secure storage in enhanced oil recovery projects. CO_2 will initially be captured from an existing fertilizer plant and, later, to an upgrader, which is awaiting construction. By 2015, 1.9 Mt could be captured and used primarily for EOR projects. The principal element of this project is that it will provide the first leg of Alberta's CO_2 transmission infrastructure.
- The government of Canada and the government of British Columbia are providing funds for the Spectra Fort Nelson project which focuses on

investigating the geological, technical and economic feasibility of a world-scale CCS project associated with Spectra Energy's existing gas processing plant in Fort Nelson, B.C., and the largest sour gas processing plant in North America. If successful, it will lay the groundwork for one of the largest CCS projects of its kind in the world, capturing approximately 2 Mt annually and transporting and storing this CO_2 permanently in saline aquifers.

- The government of Alberta is providing a grant to the Swanhills Synfuels project for their work to use *in situ* coal gasification (ISCG) to manufacture environmentally clean synthetic gas from unminable coal seams. About 1.3 Mt per year of CO_2 will be separated from the synthetic gas at a conventional gas-processing plant and the CO_2 will be transported to EOR projects in the region.
- Together with the United States and Mexico, Canada is engaged in the North American Carbon Capture and Storage Partnership. The three nations have committed to produce a North American Carbon Atlas that will result in uniform mapping methodology and data-sharing in the area of large sources of carbon emissions and potential storage sites in North America. Some information and reference to this might be included.

CRITIQUE

The federal government has identified CCS as a key technology for reconciling its economic and environmental objectives. By 2030, almost half of Canada's business-as-usual emissions would be expected to come from sources that could be amenable to CCS. That is to say, from conventional and unconventional oil and gas production, from fossil power generation, and from industry. The federal government's commitments, given in the 2008 Speech from the Throne, to a 20% reduction in 2006 GHG emission levels and that 90% of Canada's electricity should be from non-emitting sources, both by 2020, will be difficult to achieve without urgent adoption of CCS at the heart of Canada's climate change policy. Canada has abundant potential for geological storage of CO_2 and, thanks to the Weyburn-Midale project, is in a leading position in the evaluation of underground storage by means of enhanced oil recovery (EOR).

Both the federal government and the province of Alberta have invested relatively significantly in CCS-related activities, and approximately CAD 3 billion in funding towards large-scale CCS demonstration projects has been made available. This funding should now be allocated to the explicit development of projects.

CCS for coal-fired power stations is a technology of immense importance for global CO_2 abatement. The adoption of CCS in countries such as China, India and Indonesia, with large coal power station construction programmes, and in programmes for the replacement of ageing power plants in Europe and the

United States, are strategic objectives of global climate change policy. CCS for oil-sands development, on the other hand, represents a series of unique challenges for Canada, such as much higher lifecycle energy use and related CO_2 emissions, given that there are many different emission point sources, which vary significantly for ease of CO_2 capture, compared to the coal-fired power sector.

The economics of CCS depends on the availability of a large-scale point source of CO_2-rich emissions. Hydrogen production for oil-sands bitumen upgrade provides a promising source. So do coal-fired power stations. Other emissions related to oil-sands development, for instance gas-fired steam generation for *in situ* recovery, are less promising. It is therefore important that other technologies under development for lower CO_2 *in situ* oil-sands development should receive a high level of attention, alongside CCS.

Public acceptance of CCS presents another challenge to Canadian policy makers and the Weyburn project has played a key role in this regard. As a relatively new and unknown technology that proposes placing CO_2 into natural systems, CCS is exposed to public scrutiny and potentially prone to controversy. Local communities have legitimate concerns about planned CCS projects that must be addressed in a timely, transparent manner; projects that have failed to do so have been postponed or cancelled. Therefore, it is clear that public engagement and education on CCS is an important priority that requires additional government resources.

Canada participates in a number of international collaborations relevant to CCS, including the Canada-United States Clean Energy Dialogue, the Global Carbon Capture and Storage Institute, the Carbon Sequestration Leadership Forum, the Asia-Pacific Partnership, and the Energy Working Group of the Asia-Pacific Economic Co-operation. Canada has endorsed (and, indeed, played an important role in proposing) the commitment of the G8 to launch 20 large-scale CCS demonstration projects globally by 2010, taking into account varying national circumstances with a view to supporting technology development and cost reduction for the beginning of broad deployment of CCS by 2020. Canada's hosting of the G8 in 2010 provides a clear opportunity to give an international lead on a technology that is vital for Canada's future.

RECOMMENDATIONS

The government of Canada should:

- *As part of Canada's long-term climate change policy, articulate a clear strategy for the implementation of carbon capture and storage in Canada in co-operation with the most relevant provincial governments and industry. Such a strategy would assist Canada to make a significant contribution in the international development and diffusion of this important technology.*

- *Maintain its high profile and leadership in international efforts to promote and implement CCS.*
- *Commence construction of full-scale demonstration facilities as soon as possible, with an emphasis on developments in the oil-sands area.*
- *Link GHG regulation more explicitly with CCS technology promotion to help bridge the gap between the high cost today and the expected mitigation cost in the future.*
- *Expand on current public information and education efforts so as to establish a strong programme to foster support for CCS from the general public.*

NATURAL GAS

OVERVIEW

Oil and gas dominate Canada's total primary energy supply (TPES) mix, accounting for almost two-thirds of the total. Canada's vast hydrocarbon resources mean that oil and gas are likely to continue to account for the bulk of the country's TPES in the coming years. Growth in gas demand has been driven by the use of gas for power generation and for oil and gas extraction, notably in the Canadian oil-sands.

Canada is the main supplier of natural gas to the United States and is one of the few IEA member countries with the resources to grow indigenous production. Since 1999, production, largely driven by demand from the United States, remained consistently above 160 billion cubic metres (bcm).

SUPPLY AND DEMAND

SUPPLY

Canada is the world's third-largest producer of natural gas after Russia and the United States. In 2008, Canadian production was 175 bcm, 5% lower than in 2007, because of falling demand for Canadian gas in the United States and lower drilling activity in Alberta. Production greatly exceeds domestic demand and more than half of Canadian production is exported to markets in the United States.

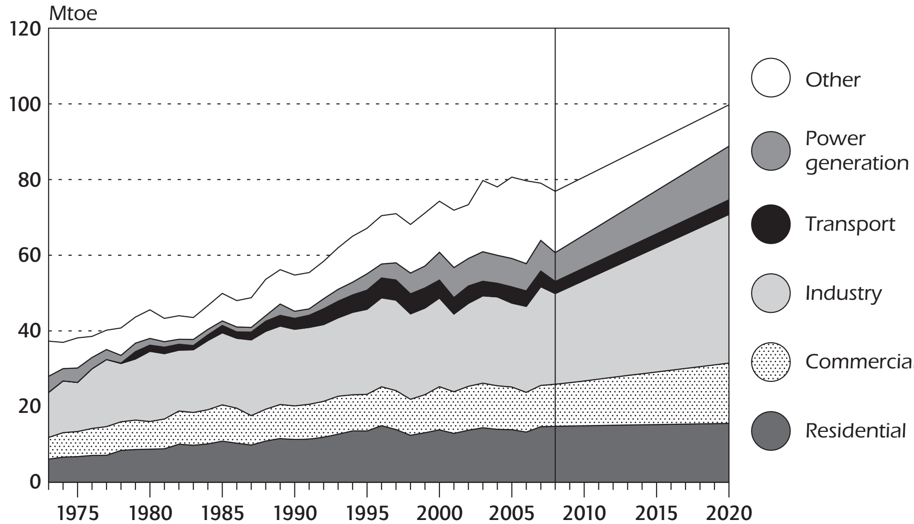
The Western Canada Sedimentary Basin (WCSB) accounts for 98% of production. Of which Alberta accounts for 80%, British Columbia and Saskatchewan for 16% and 4% respectively. The remaining 2% of domestic output is produced in Atlantic Canada, the majority from the Sable Offshore Energy Project (SOEP), offshore Nova Scotia.

The regional distribution of natural gas production in Canada is unbalanced, with Alberta and to a lesser extent British Columbia, Saskatchewan and Nova Scotia accounting for the bulk of primary energy production. Differences in resource endowment have created regional disparities, and the rise in global commodity prices seen in the years before 2009 has mostly benefited western provinces. At the end of 2007, Canada's remaining established reserves amounted to about 1.6 trillion cubic metres (tcm).[33] This is the amount of natural gas that can be recovered using existing technology under current economic conditions from known reservoirs specifically proved by drilling, testing or production. The vast majority (98%) of these reserves are found in the Western Canada Sedimentary Basin. Other notable reserves are located in offshore Nova Scotia.

33. *Energy Statistics Handbook, Second Quarter 2009,* Statistics Canada.

Figure 20

Natural Gas Supply by Sector*, 1973 to 2020



* total primary energy supply by consuming sector. Other includes other transformation and energy sector consumption. Industry includes non-energy use. Commercial includes commercial, public services, agriculture, forestry, fishing and other final consumption.

Sources: *Energy Balances of OECD Countries*, IEA/OECD Paris, 2009 and country submission

Québec and the federal government have had exploratory discussions on potential shared management arrangements regarding exploration and drilling in offshore portions of the Gulf of St Lawrence. Québec is interested in exploring the Old Harry structure offshore Québec, which has significant potential.

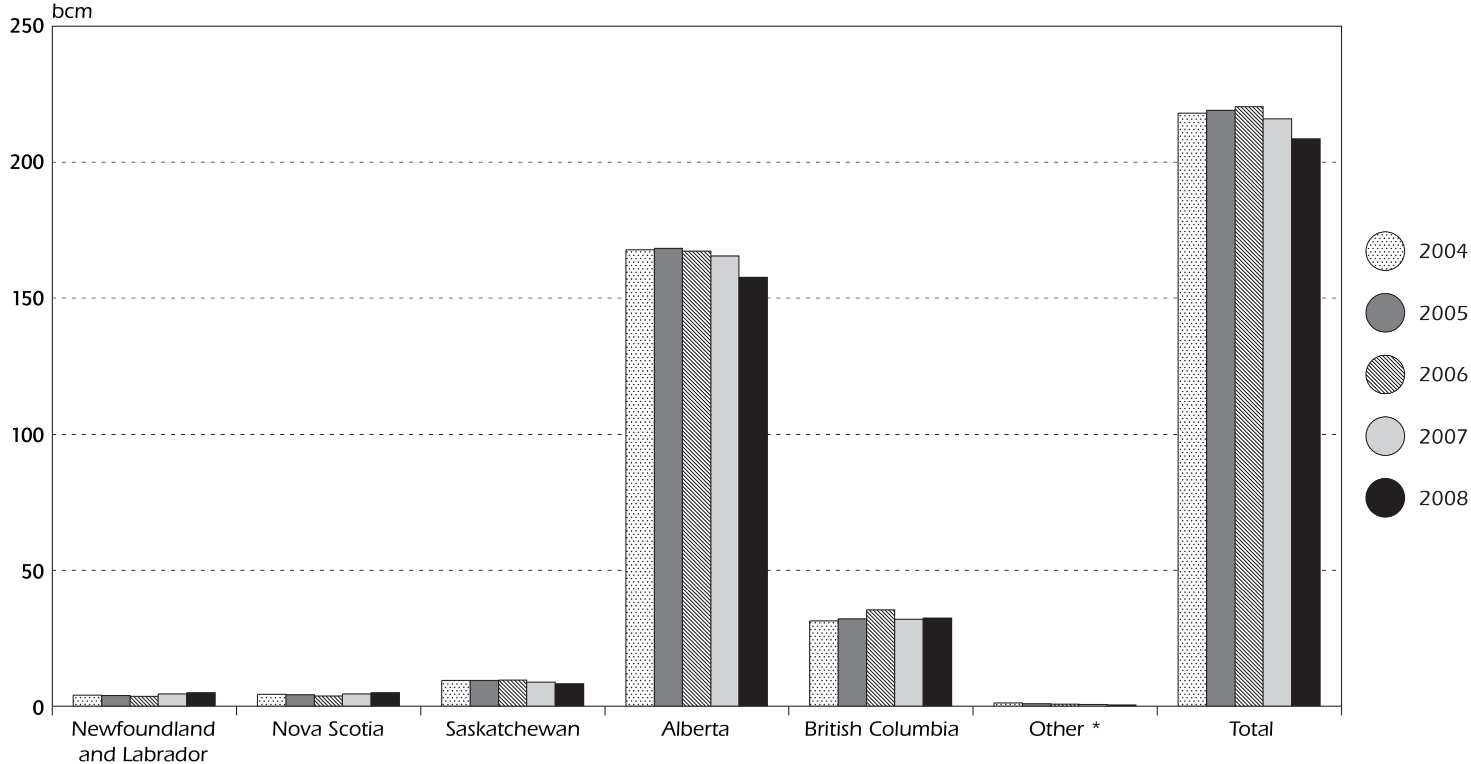
The possibility of opening areas now closed under moratorium for exploration and production is not a concern at present. In the case of George's Bank (offshore Nova Scotia), the federal Minister of Natural Resources and his/her provincial counterpart must decide in 2010 whether to conduct a public review of the moratorium. If a decision is taken to proceed with a review, the two governments would then consider the results and take a decision on whether or not to lift the moratorium. As it stands now, the moratorium is in effect until the end of 2012.

In the case of offshore British Columbia, there is no timetable to review or consider changing the policy. The federal government is not considering lifting the moratorium at this time.

The most recent consensus forecast from the federal government suggests that Canadian marketable natural gas production will remain relatively stable, reaching 167 bcm in 2020, a similar volume as in 2007, although at

Figure 21

Natural Gas Production by Province, 2004 to 2008



* includes Ontario, Yukon and Northwest Territories, but excludes Nunavut.
Source: Statistics Canada.

times it will be lower.[34] Future supply sources may include unconventional natural gas such as shale gas in north-east British Columbia and Alberta, in the St Lawrence sedimentary basin of Québec, coal-bed methane (CBM) in Alberta; and conventional gas from the Mackenzie Gas Project in the Northwest Territories and Deep Panuke in offshore Atlantic Canada or in the Gulf of St Lawrence, 80 km north-east of Magdalene Islands in Québec.

Production from British Columbia shale could potentially reverse the decline in WCSB production and by 2018 production could be boosted by output from the Mackenzie Gas Project, whose total reserves amount to 164 bcm. First gas from the Deep Panuke project is expected in late-2010 and is expected to recover 17.8 bcm over 13 years. Large undiscovered resources are located in offshore British Columbia (estimated at 1 184 bcm of gas in place) and Québec; however, these figures hold large uncertainties and a federal moratorium prohibits any offshore drilling. A moratorium is also in place for George's Bank, off the coast of Nova Scotia.

Gas from shale or tight gas resources are expected to continue to contribute significant volumes in the future. NRCan's consensus forecast has unconventional gas production growing at an annual rate of 5.1% per year and adding 22 bcm per year to Canadian supply by 2020. CBM resources in Alberta alone could be as high as 14.2 tcm.[35] Provincial estimates of shale gas and CBM resources in British Columbia range between 7 to 23 tcm and 2.5 to 7 tcm respectively. However, in the shorter term, higher drilling costs, compared to the United States, distance from existing transport infrastructure and lower market prices have delayed unconventional production in British Columbia.

Only one LNG import facility is operational in Canada at present. The Canaport LNG import terminal in New Brunswick began its first phase of operations in mid-2009. The terminal will have a send-out capacity of 28 mcm of natural gas per day when fully operational. There are proposals for five additional LNG import terminals, one trans-shipment facility and two LNG export proposals in Canada.

In addition, significant volumes of natural gas have been discovered in the Mackenzie Delta, the Beaufort Sea and the Arctic Islands. While these volumes are not considered to be "established" at present owing to the lack of transportation infrastructure to move this gas to markets, they are considerable.

New discoveries of shale and tight gas in the Western Canada Sedimentary Basin and in the St Lawrence sedimentary basin of Québec are promising for the long-term production of natural gas. However, these discoveries are new and their potential will be better known as further exploration and drilling is conducted. Canada is also believed to have enormous quantities of gas

34. *Canadian Natural Gas, Review of 2007/08 and Outlook to 2020*, NRCan, December 2008.
35. Government of Alberta.

hydrates, which are methane gases encased in frozen water found deep on the ocean floor and under permafrost areas. Information on this resource is limited, however, and there are significant technological challenges to be faced before extraction could be considered. Therefore, gas hydrates are not included in resource estimates.

UNCONVENTIONAL GAS DEVELOPMENT

While it is difficult to accurately estimate unconventional production as tight gas is not explicitly differentiated from conventional gas output, the Canadian Society for Unconventional Gas (CSUG) estimates that production from unconventional sources accounts for approximately 25% of Canadian natural gas production at present.

Unconventional gas is generally defined as natural gas that is contained in "difficult to produce" rock formations, which requires different or special completion, stimulation, and/or production techniques to retrieve the resource. Natural gas from coal, also known as coal-bed methane (CBM), or as coal-bed gas (CBG) in British Columbia, along with tight sands, shale gas, and gas hydrates are all examples of unconventional gas.

In the past, technical challenges and cost issues around producing unconventional gas deterred resource exploration and development. However, as conventional gas resources are becoming depleted and the need for energy has increased, the necessity for developing alternate resources has become important. Although production of unconventional gas in Canada is very recent, CSUG anticipates that by 2025, unconventional gas will account for about 80% of new drilling and 50% of total gas production. Meanwhile, the National Energy Board (NEB) has forecast that unconventional natural gas production will account for almost two-thirds of production by 2020 in its 2009 Reference Case Scenario.[36]

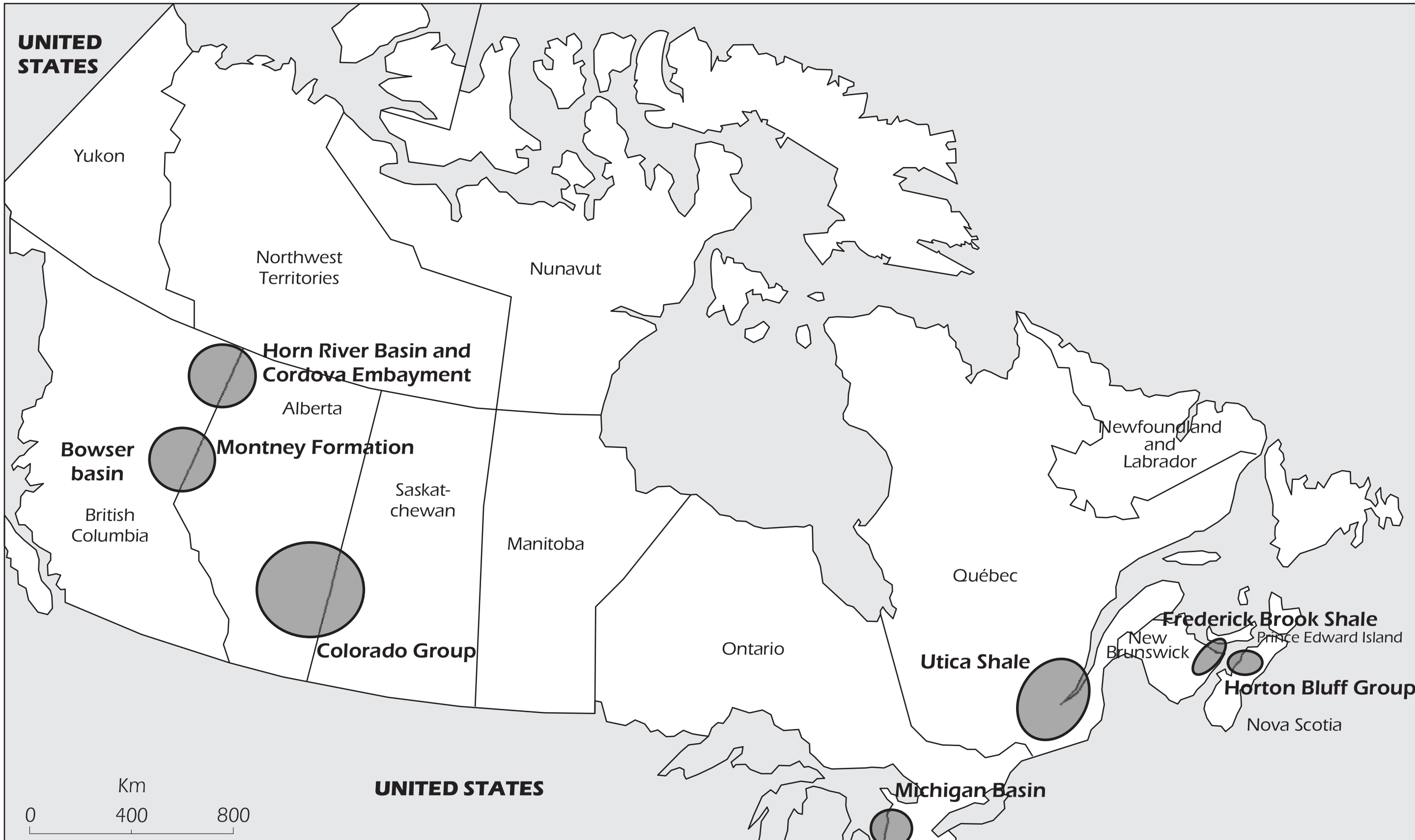
Shale gas resources are distributed across Canada but mainly in northern British Columbia; in the Horn River Basin, Cordova Embayment and the Montney Formation. Significant resources are also located in the Colorado Group in eastern Alberta/western Saskatchewan, the Québec Lowlands, Nova Scotia and New Brunswick. Outside of the Montney Formation, most of the unconventional shale gas resources are in the very early stages of development. Generally, these resources require a relatively long lead time for their development, production and deployment as optimal technologies. The pace of development will be determined by natural gas prices and probably demand from the United States.

With regard to reviewing the tax regime and ensuring a level playing field between conventional and unconventional gases, unconventional gas is

36. *2009 Reference Case Scenario: Canadian Energy Demand and Supply to 2020,* NEB, July 2009.

Figure 22

Location of Canada's Shale Gas Resources



The boundaries and names shown and the designations used on maps included in this publication do not imply official endorsement or acceptance by the IEA.

Source: Canadian Society for Unconventional Gas.

generally lower in per-well productivity and higher in cost. While exploration and production companies are subject to federal and provincial taxation, one means of reducing the cost differential between conventional and unconventional gas would appear to be royalty relief. Upstream natural gas ownership, leasing, drilling, regulation, land rentals, and royalties fall to the provinces. These already use royalty relief to encourage low-productivity wells (*e.g.* Alberta's new royalty framework offers lower royalties at a wider price range for low-productivity wells; British Columbia has brought in several royalty reforms between 2002 and 2009 to encourage exploration and production of expensive – such as deep natural gas – and unconventional sources.

ROYALTIES AND PRODUCTION INCENTIVES

The federal government does not offer incentives for natural gas exploration and development; instead its role is to maintain an effective regulatory system and to manage federal aboriginal requirements, such as constitutional obligations under Section 35 of the Constitution. Royalty regimes and production incentives for natural gas exploration and production are the responsibility of the provinces.

Tax treatment of the oil and gas sector in Canada has been undergoing fundamental reforms. Royalties are now fully deductible, and the resource allowance, a special deduction permitted in lieu of royalty deductibility, has been phased out. Corporate tax rates for the oil and gas sector, which had been higher than those for other industries, have been brought into line with the general corporate rate. Finally, the accelerated capital cost allowance for oil-sands mining and *in situ* projects (which permitted companies a fast write-off of certain kinds of assets) will be phased out, as announced in Budget 2007.

In **Alberta**, 81% of the mineral rights are owned by the provincial government, which manages those resources on behalf of Albertans. The remaining 19% are owned by the government of Canada in national parks or held on behalf of First Nations and by individuals or corporations. Industry acquires leases from the province to develop Crown resources through auctions, which occur regularly. Each year, the province holds an average of 24 land auctions and issues approximately 9 000 petroleum and natural gas agreements. In return, the province sets terms and conditions for the development and rates of royalties that the Crown is owed as steward of the resource. In March 2009, in response to a significant drop in upstream activity as a result of the global economic downturn, the Alberta government announced an incentive programme to encourage additional activity in the province's conventional oil and gas sector. The purpose of these changes was to keep drill and service crews at work and to maintain the economic benefits the industry brings to Alberta communities.

The new regime includes: a drilling royalty credit, offering up to CAD 200 in royalty credits per metre drilled on new conventional oil and natural gas wells. Maximum benefits will be provided to smaller oil and gas companies; a new well royalty reduction programme provides a maximum 5% royalty rate for all new wells that begin producing conventional oil and natural gas between 1 April 2009 and 31 March 2011.

In **British Columbia**, the province collects royalties on oil and natural gas produced from a Crown lease. The royalty regime is structured to maximise the amount of economic rent collected from produced oil and natural gas, while ensuring that producers are able to earn fair return on their investment. Since 2002, the BC government has introduced royalty rates for marginal and ultra-marginal natural gas and royalty credits for deep gas exploration, summer drilling and infrastructure development. The coal-bed methane royalty rates recognise the higher development and production costs of this resource. In 2008, the province introduced a net profit royalty programme aimed at "jump starting" unconventional, remote resources. The province made a call for proposals in early 2009 to encourage development in the Horn River Basin. The net profit programme provides a low royalty rate (2%) until capital costs are recovered. The rate then increases to a maximum of 5% of gross revenues, or 35% of net profits – whichever is greater.

In **Saskatchewan**, the Crown Minerals Act allows for the leasing of Crown mineral rights and provides the authority to collect royalties, one of the largest sources of revenue for the government, on Crown dispositions. Newly drilled oil wells in Saskatchewan qualify for volume-based drilling incentives ranging from zero to 16 000 cubic metres. Qualifying incentive volumes are subject to a maximum royalty rate of 2.5% for Crown production and a maximum production tax rate of 0% for freehold production. Newly drilled exploratory gas wells qualify for a 25 million cubic metre volume-based drilling incentive. The qualifying incentive volume is subject to a maximum royalty rate of 2.5% for Crown production and a maximum production tax rate of 0% for freehold production.

Nova Scotia has an Offshore Petroleum Royalty Regime that is based upon revenues and profits and is designed to recognise the inherent risks involved in offshore oil and gas exploration and production. The regime provides arrangements for the present Sable Offshore Energy Project, and the Cohasset-Panuke Project also contains a generic formula for future projects. Royalty rates are initially set as an increasing percentage of gross revenues before it switches to increasing percentages of net revenues. Royalty rates increase with project profitability. Once net revenue royalty levels are reached, royalties cannot be less than a specified level of gross revenues. Revenues from the Sable Offshore Energy Project account for nearly one-tenth of the provincial budget and a significant share of GDP. However, production from Sable has peaked (or will peak soon), and royalties from that project are in decline.

The province and EnCana Corporation signed an Offshore Strategic Energy Agreement (OSEA) for the Deep Panuke offshore natural gas project. It included a top tier net revenue rate of 32.5%, 12.5% above the high-risk generic rate. Deep Panuke is the only other Nova Scotia offshore project moving into production, and royalties from the project are expected to be much lower than Sable.

DEMAND

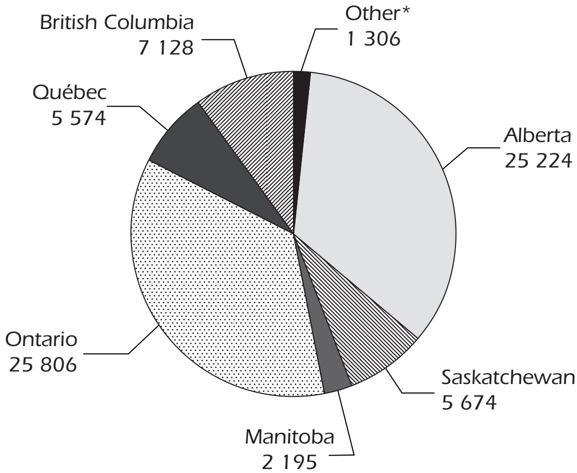
Canadian natural gas demand in 2008 was 100 bcm, a modest 1.5% increase when compared to 2007 demand. Natural gas is largely used by the energy industry for oil and gas extraction, by the electricity generation sector, and by residential and commercial consumers for space heating, particularly in the winter months. NRCan forecasts that natural gas demand in North America will increase by 1.5% per year between 2007 and 2020. Growth will be driven by demand from the energy sector for oil and gas extraction and from power generation in Ontario and Alberta. Demand from the power sector is growing and was 12 bcm in 2007, an increase of almost 12% compared to 2006 demand.

Canada's energy sector is energy-intensive and uses significant amounts of natural gas: in 2007, the energy sector alone accounted for 19% (17 bcm) of gas demand. Industrial consumption accounted for 26% (23 bcm) in 2007, and a further 18% was consumed by the residential sector.

Natural gas is widely used for residential and commercial heating, particularly in the winter months. The Canadian government estimates that residential and industrial power demand has increased by 7% and 8.1% between 2000 and 2007, respectively, while commercial demand has remained flat over the same time period. Demand for natural gas in Canada is seasonal, with peak consumption occurring in the colder winter months. Seasonality is mainly driven by the residential and commercial sectors. Natural gas demand from the industrial sector displays some seasonality, but is relatively stable. Demand from the residential and commercial sectors are lowest in the summer months, when natural gas is used primarily for cooking and water heating. According to monthly demand data from Statistics Canada, in the winter months (December to February), core demand is typically five to six times higher, as natural gas is used for home and commercial space heating. Milder (colder) winters will result in reduced (increased) demand for natural gas.

Figure 23

Natural Gas Demand by Province, 2007 (mcm)



* includes Northwest Territories, Nova Scotia and New Brunswick, but excludes Nunavut.
Source: Statistics Canada.

OUTLOOK FOR PRODUCTION AND DEMAND

Rather than forecasting natural gas production and demand, the Oil and Gas Policy and Regulatory Affairs Division at NRCan produces a "consensus forecast" of domestic and North American natural gas production and demand by taking a simple average of the long-term forecasts calculated by three well-known and respected experts. These consensus forecasts are then made public in an annual publication by the Canadian government. The most recent version was published in December 2008.[37]

Utilising the consensus forecast, NRCan estimates that demand for natural gas in Canada will rise from approximately 102 bcm in 2008 to 137 bcm in 2020, an average annual increase of about 2.3%. Demand in the industrial sector, including oil-sands production, increases by 19 bcm between 2008 and 2020, a significant increase from previous projections. Demand from power generators is expected to increase by 4.5 bcm, driven by new capacity in Alberta and Ontario, while residential demand is expected to record a marginal increase. There is less agreement regarding Canadian production. This divergence is based on differing views in relation to the

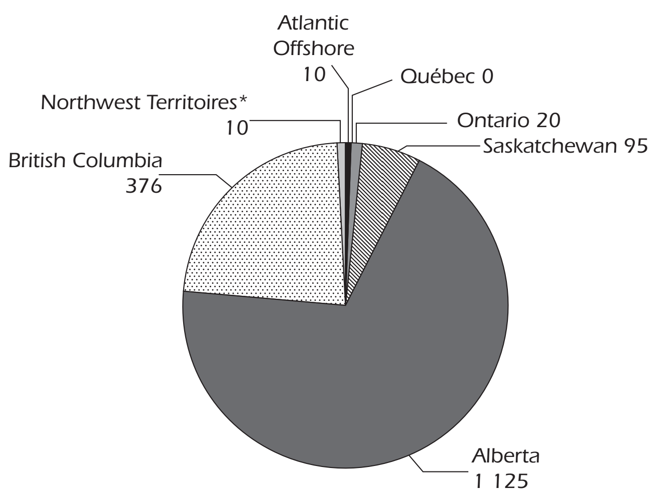
37. *Review of 2007/2008 and Outlook to 2020,* Natural Gas Division, NRCanada, December 2009.

start-up date of the Mackenzie project and the extent to which conventional production in the Western Canada Sedimentary Basin declines.[38]

The NEB's most recent energy market assessment was published in October 2009.[39] The purpose of this latest NEB report is to discuss the possible energy infrastructure implications, including the risks and challenges associated with development, based on the supply and demand forecasts presented in the 2009 Reference Case Update. It forecasts that production is expected to decline more steeply in 2009 and 2010 following a drop-off in gas drilling caused by lower prices. After 2010, prices are expected to rise as demand increases and this may encourage enough drilling to cause production to rise. Conventional natural gas from western Canada, excluding the tight gas sub-category, currently represents almost two-thirds of Canadian production, but is expected to decline to just one-third by 2020. Taking its place will be production of tight gas, shale gas and coal-bed methane.

Figure 24

Remaining Established Reserves of Natural Gas, 2008 (mcm)



* excluding Nunavut.

Source: "Marketable natural gas, remaining established reserves in Canada", Table 6.9 in Energy *Statistics Handbook Second Quarter 2009*, Statistics Canada.

38. National Energy Board 2009 Reference Case.
39. *Canada's Energy Future: Infrastructure Changes and Challenges to 2020, An Energy Market Assessment*, National Energy Board, October 2009.

INDUSTRY STRUCTURE

The upstream natural gas industry in Canada is highly competitive, with hundreds of exploration and production firms. In 2008, EnCana, the largest natural gas producer in Canada, produced approximately 18% of Canadian supply. The top 20 producers produced approximately 117 bcm of natural gas per year, and the top 100 producers approximately 145 bcm per year. The federal and provincial governments do not compete in the upstream market. Midstream, the gathering and transmission pipeline network is owned and operated by several public and private companies. There are several exceptions; notably TransGas and Swan Valley Gas Corporation, which are provincial Crown corporations, owned by SaskEnergy in Saskatchewan and Manitoba Hydro in Manitoba. Distribution is typically owned and operated by private companies that have exclusive rights to distribute gas in a given regional or local area. Distribution companies are provincially regulated and most are the only retailer in their concession area with the exception of the provinces of Alberta and Ontario, where some retail competition exists.

Storage facilities in the producing regions of western Canada are generally owned by pipeline companies or producers (in Saskatchewan, all but one storage facility is owned by the Crown Corporation TransGas); while in eastern Canada, storage facilities are typically owned by local distribution companies.

INSTITUTIONAL STRUCTURE

Under the Canadian Constitution, the provinces own all oil and natural gas resources that rest within their boundaries except for resources that rest on freehold land or federal land, and the government of Canada owns resources in certain frontier territories and offshore. The provinces, as the resource managers, are responsible for managing their resources and for upstream regulation (exploration, production, intraprovincial gathering and transmission). Provinces also have jurisdiction over downstream activities, such as local distribution, storage and marketing.

With regard to market regulation, federal powers in natural gas are primarily associated with the interprovincial and international movements of natural gas, and with works extending beyond a province's boundaries. This permits the federal government to develop policies and regulate interprovincial and international natural gas trade and pipelines. For example, federal powers govern the energy efficiency standards of equipment that crosses provincial or international borders.

The National Energy Board (NEB) is an independent federal, quasi-judicial agency established in 1959 by the Parliament of Canada to regulate international and interprovincial oil and natural gas pipelines and electric power lines, the import and export of natural gas, the export of oil and electrical power, and the exploration and development of oil and natural gas in those frontier areas not covered by provincial/federal accords.

The following are the relevant regulatory institutions with responsibility for upstream activities in the major natural gas-producing provinces:

- **Alberta**: The Energy Resources Conservation Board (ERCB) regulates the safe, responsible and efficient development of Alberta's oil and gas resources including the oil-sands and pipelines as well as coal.
- **British Columbia:** The Oil and Gas Commission regulates crude oil, natural gas and pipeline activities in the province.
- **Nova Scotia:** The Canada-Nova Scotia Offshore Petroleum Board (CNSOPB) is the independent joint agency of the governments of Canada and Nova Scotia responsible for the regulation of petroleum activities in the Nova Scotia Offshore Area. The Nova Scotia Department of Energy regulates onshore petroleum exploration and investment.
- **Newfoundland and Labrador**: The Canada-Newfoundland Offshore Petroleum Board (CNOPB) is the independent joint agency of the governments of Canada and Newfoundland and Labrador responsible for the regulation of petroleum activities in the province's offshore area.
- **Saskatchewan**: The Ministry of Energy and Resources regulates crude oil, natural gas and pipeline activities in the province.

NATURAL GAS TRADE AND TRANSIT

As the third-largest natural gas producer in the world, Canada is not dependent on imports to meet domestic demand. Nevertheless, some gas is imported via pipeline from the United States. Ontario imports some natural gas, the vast majority of which arrives in the vicinity of Dawn in south-western Ontario, where a mix of natural gas sourced from the Western Canada Sedimentary Basin (WCSB) and the United States arrives. The WCSB gas has three primary routes into Ontario: the all-Canadian route on TransCanada's Mainline pipe; the TransCanada Mainline hybrid route which brings gas across Saskatchewan and Manitoba before going south through the United States on the Great Lakes Gas Transmission Pipeline and re-entering Canada.

Canada imported just under 15 bcm of natural gas in 2008, while exporting 103 bcm of natural gas (to the United States), resulting in net exports of 88 bcm. While imports have increased considerably since 2000 (largely thanks to the completion of the Vector pipeline in 2001); gross exports have remained relatively stable, and net exports have fluctuated between 85 and 100 bcm.

Transmission Pipelines

The natural gas network in Canada is very well integrated with the United States. Pipelines lead from supply areas, such as the Western Canada Sedimentary Basin to consuming markets in the United States west coast, Midwest, and eastern Canada. Other supply areas, such as the Atlantic offshore, lead to markets in Atlantic Canada, and the north-east United States. Canada has over 80 000 km of transmission pipeline, and over 280 000 km of distribution pipeline serving approximately 6 million customers. The major new pipeline projects include the following:

Brunswick Pipeline

The principal purpose of the CAD 465 million, 145 km pipeline is to connect the Canaport LNG terminal to the United States portion of the Maritimes and Northeast Pipeline (MNP) at the international border between New Brunswick and the United States. The project will serve markets in the north-east United States and will also make new gas supplies available in New Brunswick and Nova Scotia.

Mackenzie Gas Project

The Mackenzie natural gas pipeline project (MGP) is to build a 1 220-kilometre pipeline system along the Mackenzie Valley to bring large volumes of natural gas from the Mackenzie Delta to markets in North America from three anchor fields (Taglu, Niglintgak and Parsons Lake). The proposed pipeline would connect to existing pipeline infrastructure in northern Alberta.

Westcoast South Peace Pipeline

Westcoast Energy, operating as Spectra Energy Transmission, is proposing to build and operate the South Peace Pipeline Project. The CAD 95 million, 93-km project is a proposed extension of Westcoast's existing raw gas transmission or gathering system in the Fort St. John area of north-east British Columbia (BC) to an area south of Westcoast's McMahon gas-processing plant, located at Taylor, BC. Construction work began in February 2009 and a late-2009 in-service date is planned.

Groundbirch Mainline Project

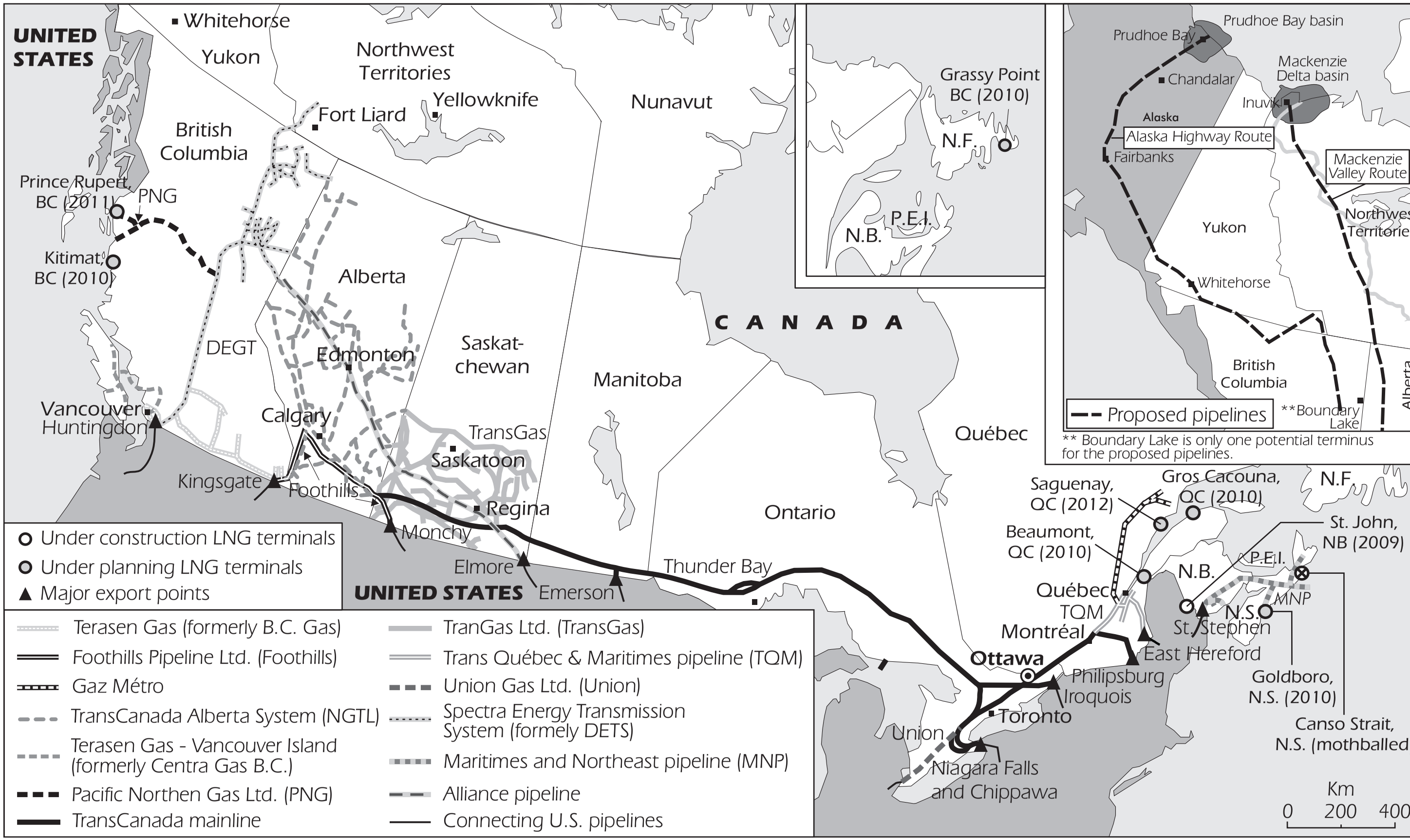
In response to the rapidly increasing production of natural gas from the north-eastern British Columbia shale basins, TransCanada's wholly owned subsidiary, NOVA Gas Transmission Limited (NGTL) is proposing to extend the Alberta System from a tie-in point downstream of the existing Gordondale Meter Station to the Groundbirch area in north-east British Columbia. The proposed CAD 251.4-million pipeline is expected to be operational in the fourth quarter of 2010, subject to regulatory approvals.

Transmission Pipeline Access

Interprovincial natural gas transmission pipelines are regulated by the National Energy Board, which ensures that open, non-discriminatory access is provided

Figure 25

Natural Gas Transmission System



The boundaries and names shown and the designations used on maps included in this publication do not imply official endorsement or acceptance by the IEA.

Source: IEA, NRCan.

to all shippers on interprovincial gas pipelines. The NEB regulates more than 68 000 km of oil and natural gas pipelines across Canada, including the newly transferred TransCanada Alberta System. The main functions of the NEB are established in the National Energy Board Act (NEB Act) and include regulating:

- the construction and operation of pipelines that cross international or provincial borders, as well as pipeline tolls and tariffs;
- the construction and operation of international power lines and designated interprovincial power lines; and,
- natural gas imports and exports, crude oil, natural gas liquids (NGL), and electricity exports.

The NEB also has regulatory responsibilities under the Canada Oil and Gas Operations Act (COGO Act) and under certain provisions of the Canada Petroleum Resources Act (CPR Act) for crude oil and natural gas exploration and production on frontier lands and certain areas off Canada's east, west and arctic coasts.

The NEB regulates the construction and operation of pipelines that cross international or provincial borders, as well as tolls and tariffs on those lines. A pipeline company cannot charge a toll unless it is included in a tariff filed with the Board or approved by an order of the Board. This tariff may also include terms and conditions with respect to a shipper's access to the pipeline, as well as the rights and responsibilities of both the pipeline company and the shipper once service begins.

A gas pipeline company's tariff also contains conditions for open season and access procedures, the minimum duration of contracts, renewal requirements and the bidding process used to secure interruptible service. In this way, gas pipeline companies provide equal and non-discriminatory access for all shippers. The NEB also has the authority under the NEB Act to direct companies to provide service for a shipper.

Firm service is typically contracted for a minimum term of one year directly between the shipper and the pipeline company. Shippers have the option to assign their capacity to other shippers, either temporarily or permanently. With some pipelines, short-term firm service is available, but generally lacks the flexibility (*e.g.* no diversion, renewal or assignment rights) of a longer-term contract, while maintaining the guarantee of delivery. Interruptible service can also be obtained by contracting directly with the pipeline company. Potential shippers who require firm or interruptible service may also sublet capacity with an existing capacity-holder on electronic bulletin boards. In principle, the sublessee has to pay for the commodity charge for the volumes actually shipped and the negotiated demand charge, which can exceed the pipeline's regulated demand charge. In practice, the pipeline operator looks to the shipper of record for payment. Pipeline operators are not always aware that assignment of capacity has taken place.

NATURAL GAS STORAGE

Storage facilities are distributed across Canada. The majority of them are in the western region. They are owned primarily by pipeline companies or producers, and used to manage pipeline flows, production levels, and to capture price arbitrage opportunities. The remaining storage facilities are in eastern Canada, owned primarily by local distribution companies (LDCs) to meet seasonal demand fluctuations. Total Canadian working gas capacity (by NRCan's calculations) is 19.2 bcm, equivalent to approximately 20% of yearly demand. An additional 0.5 bcm of capacity is planned. No public or strategic storage exists in Canada.

Natural gas is typically stored underground in depleted oil or gas reservoirs. Some facilities are salt caverns. Natural gas may also be stored above ground in LNG tanks. Currently, three such facilities exist in Canada: Hagar LNG in Ontario, Montreal East LNG in Québec, and Tilbury LNG in British Columbia. A fourth project, Mt. Hayes LNG is proposed for Vancouver Island in British Columbia.

ACCESS TO STORAGE

The regulation of natural gas storage facilities falls under provincial jurisdiction. The NEB does not regulate storage. If a storage facility is owned by a local distribution company (LDC), the rates it may charge users are regulated by the provincial regulator. If a storage facility is not owned by an LDC, its rates are unregulated and determined by the market. Developers of new storage facilities need to apply to the provincial regulator, who must then determine if there is sufficient need for a new storage facility. All new facilities must comply with provincial regulations for the safe design, construction and operation of facilities.

In September 2009 following a period of consultations, the Ontario Energy Board proposed to regulate access to storage in the province by means of a regulated third-party access regime where operators must offer standard terms of service and standard forms of contracts. TransGas, operator of a number of storage facilities in Saskatchewan, is regulated by the Provincial Cabinet and offers regulated third-party access.

LNG INFRASTRUCTURE

The Canaport LNG terminal came into service in June 2009 and is currently Canada's only *operational* LNG import facility. Several other LNG import and export proposals are still under consideration. Most of the import proposals are

Table 11
Natural Gas Storage Facilities

Province	Company	Regulated	Facility name	Capacity		Injection/withdrawal rates	
				bcf	mcm	mcf/day	mcm/day
British Columbia	Unocal Canada	No	Aitken Creek	67.0	1 896.2	661/565	18.7/16.0
	Terasen Gas	Yes	Tilbury	0.6	17.0	4.24/4.24	0.1/0.1
Alberta	ATCO Midstream	Yes	Carbon	40.0	1 132.1	369/550	10.4/15.6
	Niska Gas Storage	No	Suffield	85.0	2 405.6	NA/1800	NA/50.9
	Encana	No	Hythe	10.0	283.0	NA/200	NA/5.7
	Niska Gas Storage	No	Countess	40.0	1 132.1	800/1250	22.6/35.4
	CrossAlta	No	CrossAlta	50.0	1 415.1	NA/480	NA/13.6
	TransCanada	No	Edson	50.0	1 415.1	725/725	20.5/20.5
	Alberta Hub	No	ENSTOR & Unocal	45.0	1 273.6	NA/750	NA/21.2
	ATCO	No	Ft. Saskatchewan	3.5	99.1	NA/560	NA/15.8
	TransGas	No	Several	32.8	928.3	NA/NA	NA/NA
Total western Canada				423.9	11 997.0		
Ontario	Union Gas	Yes	Dawn	150.0	4 245.2	NA/2500	NA/70.8
	Enbridge	Yes	Tecumseh	96.0	2 716.9	NA/1750	NA/49.5
	Union Gas	Yes	Hagar	0.6	17.0	NA/49.4	NA/1.4
Québec	Gas Métro	Yes	Point-du-Lac/St. Flavien	4.8	135.8	NA/NA	NA/NA
	Gas Métro	Yes	Montreal LNG	2.0	56.6	NA/205	NA/5.8
Total eastern Canada				253.4	7 171.6		
Total Canada				677.3	19 169.0		

Source: NRCan.

on hold on account of: *i)* difficulties in securing long-term supply commitments; *ii)* concerns over existing excess regasification capacity in North America; and *iii)* the prospects for domestic shale gas as a new long-term source of natural gas. In addition to the Canaport LNG facility, other proposals include:

Atlantic Canada

- Maple LNG regasification project in Nova Scotia (on hold);
- Newfoundland LNG Ltd. proposes a trans-shipment and storage terminal for Grassy Point (on hold).

Québec

- Cacouna LNG (on hold since 2008);
- Energie Grande-Anse's proposal (on hold);
- Rabaska LNG (on hold).

British Columbia

- WestPac LNG Corporation's import terminal at Texada Island (on hold);
- Kitimat LNG Inc. changed plans from an import to an export terminal in 2008 on account of an expected surge in natural gas volumes in British Columbia along with higher prices in Asia. The company has in recent months announced Memoranda of Understanding with suppliers and also MOUs to ship the gas to Asia;
- Teekay Corporation and Merrill Lynch Commodities Inc. plan to jointly develop a project to convert the S/S Arctic Spirit into a floating LNG liquefaction plant.

The two proposals to export LNG from British Columbia to Asian markets are gaining traction. Kitimat LNG is proposing to construct and operate an LNG export, liquefaction and LNG send-out terminal at Bish Cove near the Port of Kitimat, British Columbia. The terminal will take delivery of gas via a pipeline lateral, approximately 15 km-long, from the Pacific Trail Pipelines, which will be connected to Spectra Energy's *existing* Westcoast Pipeline system. The proximity of the terminal to the existing natural gas transmission infrastructure is one of the advantages of this project, and ensures supply has easy access to the Kitimat terminal.

As for the other proposed project, Teekay Corporation and Merrill Lynch Commodities Inc. plan to jointly develop a project to convert the S/S Arctic Spirit into a floating LNG gas plant, to be moored alongside a pier near Kitimat, British Columbia. The converted vessel would have the production capacity to liquefy 100 mcm/day of pipeline quality gas.

Table 12

Canadian LNG Projects

Project name	*Sponsors*	*Location*	*Capacity*
LNG regasification			
Énergie Grande-Anse	Énergie Grande-Anse Inc. Saguenay Port Authority	Grande-Anse, Québec	10 bcm/year
Rabaska LNG	Gaz Métro Enbridge Inc. GDF SUEZ	Lévis, Québec	500 mcm/day
Keltic/Maple LNG	Keltic Petrochemicals Inc. 4Gas	Goldboro, Nova Scotia	10 bcm/year
Grassy Point (trans-shipment facility)	Newfoundland LNG Ltd.	Grassy Point, Placentia Bay, Newfoundland	10 bcm/year
Cacouna LNG	TransCanada and Suncor Energy	Cacouna, Québec	500 mcm/day
Westpac LNG	WestPac LNG Corporation	Texada Island, British Columbia	500 mcm/day
LNG liquefaction			
S/S Arctic Spirit	Teekay Corporation and Merrill Lynch Commodities Inc.	Kitimat, British Columbia	100 mcm/day
Kitimat LNG	Galveston LNG Inc.	Bish Cove, Port of Kitimat, British Columbia	700 mcm/day

Source: NRCan.

LNG TERMINAL ACCESS

Information regarding terms of access to LNG terminals in Canada is limited as the first terminal only commenced operations in mid-2009. The Canaport LNG terminal in St. John, New Brunswick is jointly owned by Repsol (75%) and Irving Oil (25%). Irving Oil, the owner of Canada's largest oil refinery, will operate the terminal. Repsol has contracted for 100% of the plant's capacity for 25 years, the bulk of which it will market in north-eastern United States. Initial supplies will come from Trinidad and Tobago and in the longer term it is possible that supplies may be sourced from Algeria (Gassi Touil).

Earlier in 2009, the NEB approved an application by Repsol for a long-term licence authorising the importation of LNG into Canada, and a separate licence to export regasified LNG from Canada to the United States.

NATURAL GAS TRADING

Canada's main natural gas trading hub is in Alberta. TransCanada's Alberta System (also known as the Alberta Hub, NOVA or AECO) is extensive and covers most of the province of Alberta. The AECO spot price – the Alberta gas trading price – has become one of North America's leading spot price references.

TransCanada's wholly owned subsidiary, NOVA Gas Transmission Ltd (NGTL), is the owner of a natural gas transmission system known as the Alberta System. The Alberta System, previously regulated by the Alberta Utilities Commission (AUC), is a 23 500 km pipeline network that gathers natural gas for use both in Alberta and for delivery to provincial border points for export to North American markets. It is one of the largest systems in North America and gathers 66% of the natural gas produced in Western Canada.

TransCanada applied to the National Energy Board (NEB) in June 2008 to change its Alberta System from provincial to federal jurisdiction. Before April 2009, the Alberta System was regulated by the Alberta Energy Utility Board. In February 2009, the NEB granted TransCanada's application recognising that the Alberta System is under federal jurisdiction. According to the NEB, the decision was taken on the ground that the Alberta System is part of TransCanada's extensive pipeline system already under federal jurisdiction. This regulatory change, which took effect on 29 April 2009, recognises the interprovincial nature of TransCanada's existing pipelines, and allows NGTL to expand its pipeline network outside Alberta for the first time in over 50 years, subject to regulatory approval.

The Alberta hub and the intra-Alberta market are among the most important natural gas hubs/markets in North America, on account of the large volume of natural gas flowing through the hub every day, and the large volume of natural gas exchanged at this location. The importance of the hub is also enhanced by the large volume of underground natural gas storage connected to the hub in Alberta (approximately 9 bcm), and the extensive connections to other pipelines, which lead to domestic and export markets outside Alberta. The importance of the Alberta hub is reflected in the fact that the intra-Alberta natural gas spot price is one of North America's leading natural gas price-setting benchmarks.

Natural gas is generally purchased on a short-term basis. Regulated local distribution companies, that are required to sell natural gas at cost, are prevented by the regulatory regime from purchasing natural gas on a long-term contractual basis. Rather than entering in long-term physical contracts for natural gas, gas marketers hedge themselves against price risk by using financial instruments such as forward contracts.

The Natural Gas Exchange (NGX), headquartered in Calgary, Alberta, provides electronic trading, central counterparty clearing and data services to the North American natural gas and electricity markets. Since beginning operations in February 1994, NGX has developed the AECO hub into one of the most liquid spot and forward energy markets in North America. An average of 0.5 bcm per day is traded via the NGX in Alberta. This compares to an average of 0.3 bcm per day of physical flows into and out of the Intra-Alberta pipeline system.

DISTRIBUTION AND RETAIL

Distribution is undertaken by local and regional public or private companies (with the exception of province-owned SaskEnergy in Saskatchewan) that have exclusive rights to deliver gas in each distribution area at a regulated rate. The local distribution rates are regulated by provincial regulatory boards or commissions, or directly by a provincial government.

In most provinces, customers may purchase natural gas directly from the distributor, and pay a charge equal to the commodity price for the natural gas, plus a regulated distribution charge, and a regulated long-haul transportation charge. Consumers in British Columbia, Alberta and Ontario can purchase natural gas from a retailer. Retailers in these jurisdictions offer a one- to five-year fixed price for natural gas.

PRICES

Natural gas prices received by producers have been deregulated in Canada since 1985. The price of natural gas is determined in the open market by fundamentals of supply and demand – no price floors or ceilings exist for producers. However, the tolls charged by transmission and distribution companies remain regulated.

Customers can buy their natural gas from a local distribution company (LDC) at the commodity price, plus a regulated transportation and distribution charge; or, if they value price certainty, they may enter a long-term contract with a natural gas marketer, or retailer. With a marketer, consumers pay a fixed commodity price for gas for a period of several years, but pay the same regulated transportation and distribution charge as they would if they purchased their gas from the LDC.

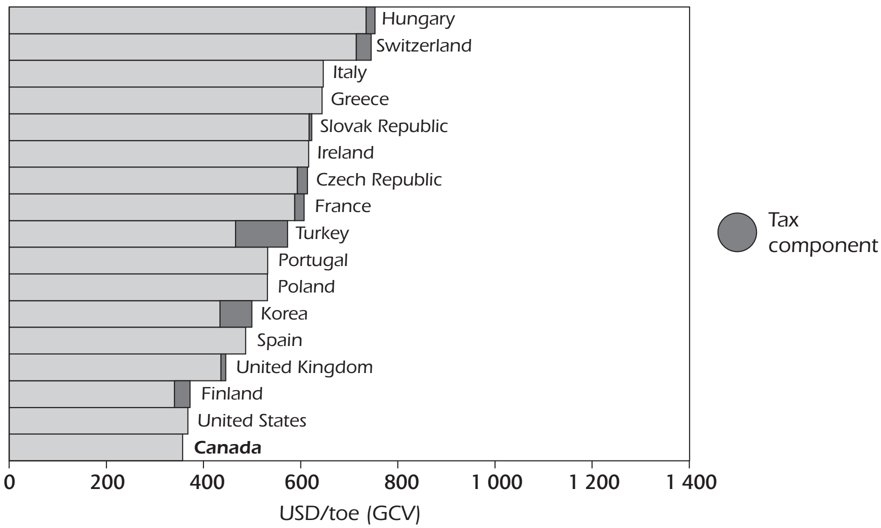
Provincial policies generally discourage LDCs from extensive long-term gas purchasing or price hedging using financial instruments. Of the eight provinces consuming gas, British Columbia and Québec appear to allow the most hedging or long-term contracting directly with their LDCs. Customers still retain the option of hedging using the services of a gas retailer.

In British Columbia, Alberta and Ontario, residential and commercial customers can purchase one- to five-year fixed price contracts for natural gas directly from retailers. Therefore, residential and commercial customers have the option to hedge against price volatility by purchasing a fixed price contract.

Figure 26

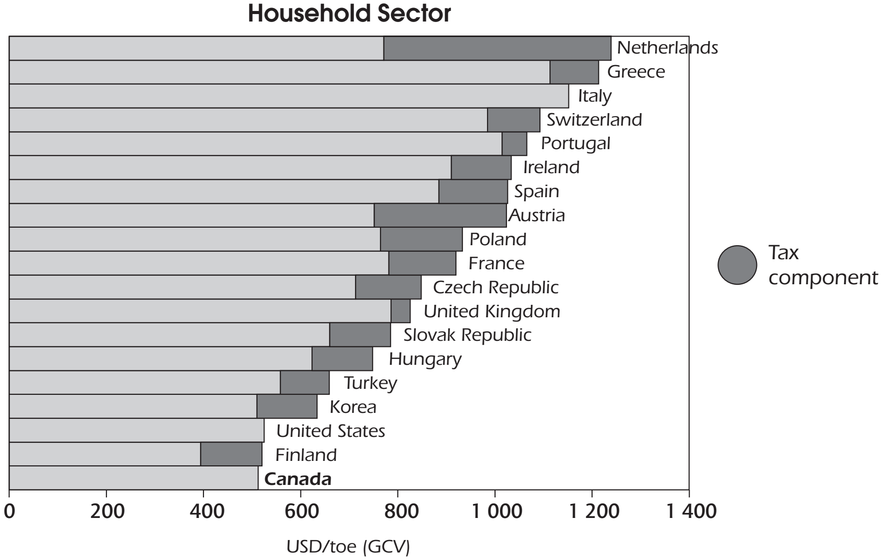
Gas Prices in IEA Member Countries, 2008

Industry Sector



Note: Tax information not available for the United States. Data not available for Australia, Austria, Belgium, Denmark, Germany, Japan, Luxembourg, the Netherlands, New Zealand, Norway and Sweden.

Household Sector

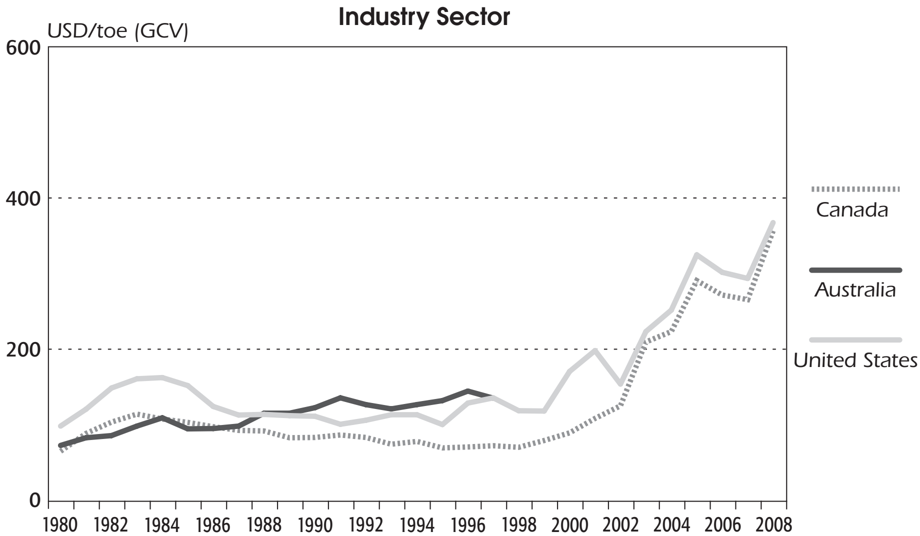


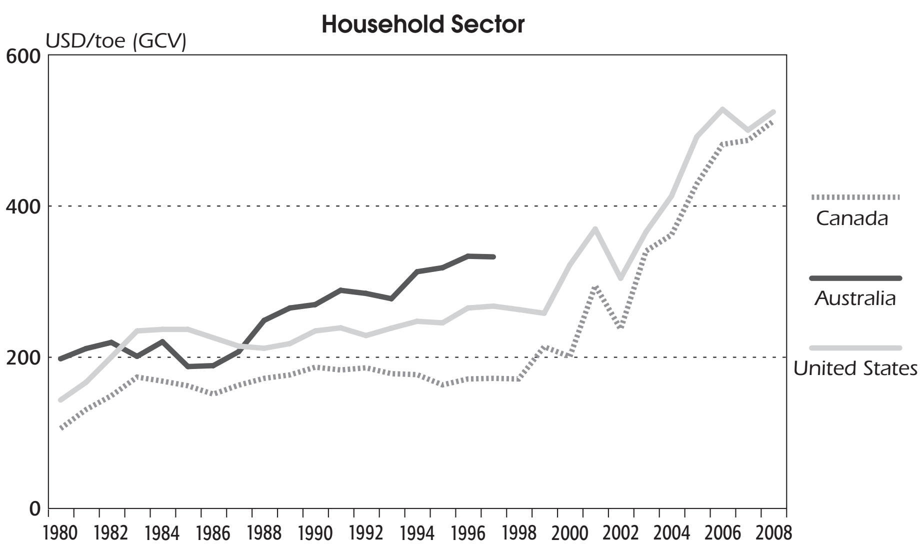
Note: Tax information not available for the United States. Data not available for Australia, Belgium, Denmark, Germany, Japan, Luxembourg, New Zealand, Norway and Sweden.

Source: *Energy Prices and Taxes*, IEA/OECD Paris, 2009.

Figure 27

Gas Prices in Canada and in Other Selected IEA Member Countries, 1980 to 2008





Source: *Energy Prices and Taxes*, IEA/OECD Paris, 2009.

SUBSIDIES

There are no federal subsidies for production or consumption of natural gas.

DEMAND-SIDE MANAGEMENT

Of the dozen or so natural gas utilities, most offer a comprehensive portfolio of demand-side management (DSM) programmes. From 2000 through 2007, more than CAD 288.7 million was invested in DSM in Canada. Annual DSM expenditures increased steadily over the first four years of this period, and more dramatically over the latter three years, with the total expenditure in 2007 (CAD 69.8 million) being more than four times that of 2000 (CAD 16.6 million). The growth is due to both an increase in the number of companies participating in DSM and an increase in DSM budgets within individual companies. The annual energy savings from these DSM investments increased from 0.08 bcm in 2000 to 0.2 bcm in 2007.

The portfolio of programmes offered by each LDC differs: most offer residential and commercial/institutional programmes and others offer a variety of programmes, including programmes targeted on low-income customers, equipment replacement (*e.g.* upgrading to a high-efficiency furnace), building retrofits and education campaigns to domestic consumers. Energy audits and equipment replacement are among the most common commercial/institutional programmes. Industrial programmes are predominantly "custom projects", where the specific energy efficiency measures installed are identified on the basis of the individual needs of each customer.

REGULATORY REFORM

The Major Projects Management Office (MPMO) is a federal government organisation whose role is to provide overarching management of the federal regulatory review process for major natural resource projects. It was established in 2007 to support the government of Canada's new approach to the regulatory review of major resource projects – an approach that ensures a more effective, accountable, transparent and timely review process.

The MPMO operates in close collaboration with other federal regulatory departments and agencies to identify areas where the efficiency and effectiveness of the regulatory system can be improved and to develop and implement innovative new approaches to continually improve performance. Key activities include providing a single window into the federal regulatory system for all stakeholders, negotiating project-specific service standards, measuring and reporting on performance, providing selective intervention to address key issues, and leading collaborative research to identify further improvements. The MPMO also provides strategic policy advice and support to the Major Projects Deputy Ministers' Committee, which has been established to provide broad oversight and direction for federal regulatory activities pertaining to major resource projects.

Projects currently managed by the MPMO include the Northern Gateway, Groundbirch, Keystone XL, and Horn River pipeline projects.

The National Energy Board (NEB) also streamlined the application process for small, interprovincial Group 2 pipelines in 2008. This new streamlined process is online, and automated to assess each project according to transparent risk criteria.

GAS EMERGENCY POLICY

The federal government has considerable powers to control natural gas flows in the event of a national emergency under the Emergencies Act. If a national emergency is not declared, however, natural gas flows are dictated by market forces, including supply and demand.

Supply disruptions can be either long-term or short-term. Long-term risk is not particularly relevant for North America, as its natural gas market is resource-rich and is an open, competitive commodity market with many buyers and sellers. Supply and demand are balanced daily, by storage operations and daily price movements. By definition, natural gas supply will equal natural gas demand over the long term. Available supplies tend to clear the market; price is what fluctuates. As a result, in North America, the risk is not a disruption in supplies, but rather that prices may be higher than expected.

Because of the wide diversity of supply areas, pipelines and upstream/downstream storage in North America, an accident or weather-related problem would not affect all gas supplies. Physical supply of gas might be a problem for a small segment of the market, but the main effect would be a price increase as a result of a smaller volume of gas.

There are no government-imposed requirements for any market participants to hold any minimum level of stocks. In case of a major supply disruption, there are a number of options for continuing to meet natural gas demand:

- Canada has significant natural gas storage reservoirs that are usually used for servicing peak winter demand. Canada has approximately 20 bcm of storage capacity (equivalent to about 20% of yearly demand), while the United States has an additional 85 bcm. These storage volumes can be drawn down at very short notice to help address a supply shortfall, particularly outside peak demand periods.

- While Canada is a net exporter of natural gas, there are also several options for importing gas. In the event of a supply disruption, Canada could import additional natural gas via pipelines from the United States.
- In the event of a prolonged shortage of natural gas in the Maritime Provinces, buyers could bid on potential spot LNG cargoes now that the Canaport terminal in St John, New Brunswick is fully operational.
- Many industrial natural gas consumers are on "interruptible" service contracts, which means they can be denied natural gas if it is required elsewhere. Shedding demand through interruptible service clients would help in case of a supply disruption.
- Other industrial gas consumers, including the power generation sector, have some degree (albeit limited) of fuel switching capability, which could serve to reduce demand further.

CRITIQUE

Canada is a country endowed with relatively large natural gas resources, especially from unconventional sources. These resources are spread over a very large and diverse land area. Much activity, conventional and unconventional, is concentrated in a small number of producing provinces. In general, Canada is handling the challenges related to its upstream natural gas activity in a sound manner. It is at the forefront of producing countries when it comes to management of resources and also with regard to research and technological development. This is especially the case in relation to production from unconventional resources.

There are a number of strategic investment issues facing the oil and gas industry, for instance the development of the Far North and the options for accessing international markets beyond the United States. The federal government should continue to be alert to these issues and keep under review the impact that taxation and regulatory policies may have on the outcome. However, it should also maintain its broad policy approach in which investment decisions are left to the private sector.

The federal system in Canada presents the provinces with a large degree of autonomy, and ensures that local stakeholders in the territories to the north have a voice and are involved in decision-making processes with regard to natural gas activity in their regions. This degree of autonomy, however, also represents some of the greatest challenges for Canadian resource management.

One of the most challenging producing regions in Canada, and perhaps in the world, is the northern territories (Yukon, Northwest Territories and Nunavut), located a long way from markets and where extreme climatic conditions prevail. A prerequisite for drawing adequate interest from companies to undertake exploration and production activity in this part of the country is the presence of a competitive and stable environment with regard to both the regulatory framework and the tax regime. Market price is also a factor, as it is relatively expensive to bring the gas to market.

The regulatory framework in the North is often very complex and far-reaching. There appear to be an emerging trend of a growing complexity in the regulatory framework with the creation of new regulatory bodies. This is a trend that may continue into the medium term as a result of more aboriginal land claims being negotiated and settled, and this complex regulatory structure constitutes a very real obstacle to new investment in these areas. In addition to this being a challenge for the predictability and the timeliness in application processes for the industry, this also presents a challenge to the individual territories in terms of the human resources that are needed to undertake the responsibilities of the many different regulatory bodies.

The Northern Regulatory Improvement Initiative is an important initiative to improve the regulatory processes in the North. The Canadian government should build on this and increase its focus on improving the regulatory regimes in the northern territories, for example by simplifying regulatory processes and reduce the number of regulatory bodies involved.

The challenge of a complex regulatory framework is however not limited to the northern territories. For projects elsewhere, the establishment of the Major Projects Management Office (MPMO) is an important step on the way to make more predictable and timely review processes. The role of the MPMO should however be strengthened by establishing a legislative mandate for its activities. As a general principle, the aim should be that environmental evaluation by all regulatory bodies should be carried out on the basis of a single environmental assessment.

In the North, the ability to move resources is crucial to sustain further activity in the region. The building of the Mackenzie pipeline is, in this respect, of great importance to the development of production activities in the Northwest Territories. It is important that the regulatory processes for obtaining the necessary permissions for this pipeline receive a clear focus from the Canadian authorities if it is to meet its current commissioning deadline in 2015.

There are several areas under federal or jointly federal/provincial jurisdictions where there are moratoriums on natural gas and petroleum activities (offshore British Columbia, Georges Bank and Southampton Island, and Coats Island). The areas now closed for activity may contain substantial resources, particularly in the areas offshore British Columbia. At the same time, the relevant seismic data are obsolete and incomplete. Furthermore, there will be a considerable time lag between possible future decisions to open an area for petroleum activity and the time petroleum or natural gas production from the area commences.

A federal review process regarding petroleum activity in offshore British Columbia was undertaken in 2003/04 but it did not result in any changes to the moratorium. Technological development and improved knowledge regarding the environment and natural resources can however ensure that activity that in the past was considered unsafe may become possible. Given the long lead times before production and the potential for considerable additional resources, the government of Canada should continue to consider the possibility of sound and sustainable activity in these areas. This could be done by filling knowledge gaps and improving necessary data, especially those relating to estimates of resources, in order to prepare for well-founded decisions regarding activities in these areas in the future.

The natural gas market in Canada is resource-rich, efficient, competitive and diversified as it is throughout North America as a whole, and the present structure of the natural gas market provides a high degree of energy security.

RECOMMENDATIONS

The government of Canada should:

- *Work on a multilateral basis with the governments of the northern territories to improve the regulatory regimes for natural gas exploration and production in the North, and to make them simpler and more predictable.*
- *Strengthen the role of the Major Projects Management Office by providing it with a legislative mandate.*
- *Focus on ensuring that the regulatory framework is in place to facilitate the delivery of the infrastructure necessary to transport natural gas to markets.*
- *Collect additional geological and environmental data to facilitate informed decisions on whether to open new areas for petroleum and natural gas activity.*

OIL

OVERVIEW

Canada is the OECD's largest exporter of oil and the second-largest OECD producer of crude oil after the United States and Mexico.[40] Canada is one of the few countries outside the Organization of the Petroleum Exporting Countries (OPEC) with significant prospects for production growth. Unlike many countries, Canada produces more oil than it consumes and this is projected to continue in the foreseeable future. Between 2000 and 2008, production consistently increased, as new oil-sands and offshore production replaced declining production from ageing conventional fields. The oil-sands are a key part of energy security for Canadians and for the North American market. Total Canadian proven oil reserves, the vast majority of which are unconventional, are estimated at 175.4 billion barrels, making it the world's second-largest reserve-holder. More than 95% of this resource is located in the oil-sands of Alberta. Canada's vast hydrocarbon reserves mean that oil and gas are likely to continue to account for the bulk of the country's total primary energy supply (TPES) in coming years.

Over the last decade, there has been a rapid increase in investment in Canada's upstream petroleum industry. Investment has tripled from CAD 16.2 billion in 1998 to about CAD 46.8 billion in 2007 and an estimated CAD 47.7 billion in 2008. Investment growth has been strongest in the oil-sands industry, which has increased twelvefold over the last decade, from CAD 1.5 billion in 1998 to CAD 18.1 billion in 2007. Recent falls in oil prices and the global economic crisis have had a significant impact on investment conditions and resulted in the postponement of a number of oil-sands projects.

In 2009, according to the Canadian Association of Petroleum Producers (CAPP), investment in oil-sands is projected to fall to CAD 10 billion owing to the effects of falling oil prices and the global economic crisis. For 2010, with an anticipated rebound in oil prices, CAPP forecasts an increase in oil-sands investment to CAD 12 billion. It is worth noting that a number of the postponed projects in the oil-sands are coming back on line; for example in November 2009, Suncor announced that it would spend CAD 900 million in 2010 to resume work at the Firebag Stage 3 *in situ* oil-sands expansion, which was approximately 50% complete before being deferred in early 2009. Suncor now expects the project to begin production in the second quarter of 2011 with volumes then beginning to ramp up towards design capacity of approximately 68 000 barrels per day (bpd) of bitumen. Spending will also be directed to Firebag Stage 4 to support a target of first bitumen production in the fourth quarter of 2012. Stage 4 also has a design capacity of 68 000 bpd.

40. Source: Table 18, "World Crude Oil and NGL Production" in *Oil Information*, IEA Paris, 2009.

SUPPLY AND DEMAND

SUPPLY

Conventional oil reserves in Canada are estimated at approximately 4.8 billion barrels and proven recoverable unconventional oil reserves from the oil-sands are estimated at 175.4 billion barrels. If these resources are considered together, Canada displaces Iran as the world's second-largest oil-resource holder, behind Saudi Arabia's 260 billion barrels. Ultimate potential (recoverable) reserves of the Canadian oil-sands have been estimated at 315 billion barrels. In 2008, conventional light, medium, heavy and offshore oil, and condensate, accounted for about 2.7 million barrels per day (mb/d) of production.[41] Marketable oil-sands production (synthetic crude oil and non-upgraded bitumen) accounted for the remaining 1.2 mb/d.

Although Canada's oil resources are geographically dispersed, most oil production is within the Western Canada Sedimentary Basin, principally within the provinces of Alberta and Saskatchewan. Together, in 2008, these two provinces accounted for 84% of Canadian crude oil production. Offshore Newfoundland and Labrador also produces relatively large volumes of crude oil and this is forecast to continue into the future; in 2008, Newfoundland and Labrador accounted for around 13% of Canadian oil production. Light crude oil production from the Bakken field in Saskatchewan is expected to grow in the next few years and the Hebron heavy oil project in Atlantic Canada is expected to come on stream by 2017.

According to the National Energy Board, total Canadian crude (light, heavy and upgraded bitumen) oil production stood at 2.7 mb/d in 2008, and is estimated to increase to about 2.9 mb/d in 2010. Despite a significant drop in crude oil prices with the recession of 2008/09, Canadian crude oil production was virtually unchanged in the first half of 2009 compared with the first half of 2008. Even with a significant drop in conventional drilling rates, in the first half of 2009, Canada's crude oil production of about 2.7 mb/d fell by only 0.1%, compared with the first half of 2008. Growth in oil-sands output replaced falling conventional production. With the recent increase in oil prices, conventional drilling rates could grow substantially, which would increase Canada's oil production rate.

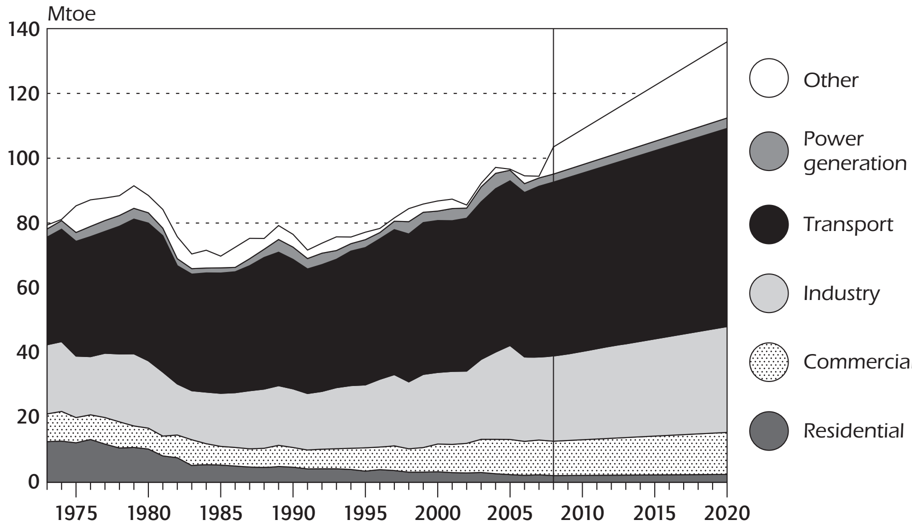
Between 2002 and 2008, total crude oil production grew at an annual average of 3%, largely sustained by the growth of production from oil-sands which grew by 10% per annum during the same period, largely replacing declining production from ageing conventional fields. The Canadian Energy Research Institute estimates that by 2015, total oil production could reach 4 mb/d, with oil-sands production accounting for 2.1 mb/d. IEA's June 2009 *Medium-Term Oil Market Report* estimates that Canadian oil production will

41. Estimated Production of Canadian Crude Oil and Equivalent, 2008 Data, Revised November 2009, National Energy Board.

reach 3.78 mb/d by 2014. Canada's crude production is expected to become increasingly dominated by oil-sands bitumen blends and synthetic crude.

Figure 28

Oil Supply by Sector*, 1973 to 2020



* total primary energy supply by consuming sector. Other includes other transformation and energy sector consumption. Industry includes non-energy use. Commercial includes commercial, public services, agriculture, forestry, fishing and other final consumption.

Sources: *Energy Balances of OECD Countries,* IEA/OECD Paris, 2009 and country submission.

The National Energy Board Reference Case estimates that the oil-sands could represent around 73% of the various crude products produced in Canada by 2020, up from about 45% in 2007.[42] The CAPP forecasts an average annual growth rate in oil-sands production of 6% over the forecast period.[43] According to CAPP, present oil-sands production of 1.3 mb/d is forecast to increase to 2.2 mb/d in 2015 then to 3.3 mb/d by 2025. According to the Canadian Energy Research Institute, the oil-sands are expected to contribute over CAD 1.7 trillion to the North American economy over the next 25 years.

Canadian bitumen and synthetic crude oil are used domestically and are exported to the United States. The current production trend is expected to move towards *in situ* operations (instead of mining projects) as just 20% of Alberta's proven bitumen reserves can be mined, while the remaining 80% requires some form of i*n situ* recovery. In addition, *in situ* production can involve relatively

42. Source: 2009 Reference Case Scenario: Canadian energy demand and supply to 2020 - An Energy Market Assessment, July 2009, National Energy Board.
43. *Crude Oil Forecast, Markets & Pipeline Expansions*, Canadian Association of Petroleum Producers, June 2009.

smaller amounts of capital investment upfront and its profitability can be secured with smaller outputs. Compared with bitumen mining projects, *in situ* projects also have lower labour costs and a smaller environmental footprint.

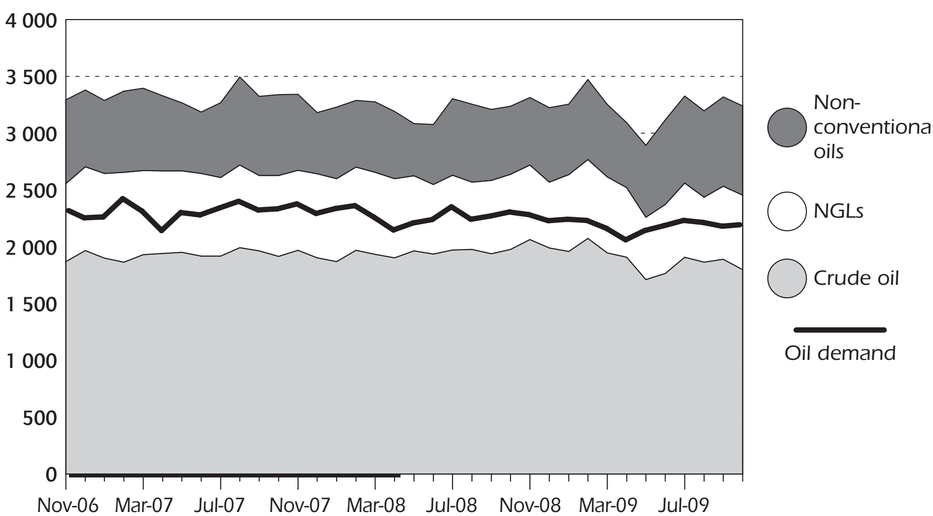
DEMAND

Total oil demand in Canada averaged 2.32 mb/d in 2008, down slightly from 2.36 mb/d in 2007. The transport sector accounted for some 55% of demand and the industrial sector for 23%. Neither the IEA nor the Canadian government forecast a notable increase in demand in the coming years. The IEA's *Medium-Term Oil Market Report* forecasts demand dropping marginally to 2014, falling to 2.29 mb/d.

In the National Energy Board's 2009 Reference Case Scenario from 2008 to 2020, exports are forecast to increase by 60% to 2.8 mb/d.[44] Both light and heavy crude register similar percentage increases in exports over the period 2008 to 2020. In comparison to the 2007 report, the total export volume decreases by 2% from 2.9 mb/d, reflecting a lower production outlook.

Figure 29

Oil Production and Domestic Demand



Source: NRCan.

The Reference Case Scenario notes two key areas of uncertainty that will influence the oil supply outlook contained in the analysis: economic factors and future

44. *2009 Reference Case Scenario: Canada Energy Supply and Demand to 2020*, National Energy Board, July 2009.

environmental policies. Underinvestment in oil supply projects at present may lead to an oil price spike in the medium term should the global economy begin to recover. Increased volatility of oil prices makes investment decisions to expand production more challenging. This is particularly relevant in Alberta where a number of upgrader projects have been postponed in the past eighteen months.

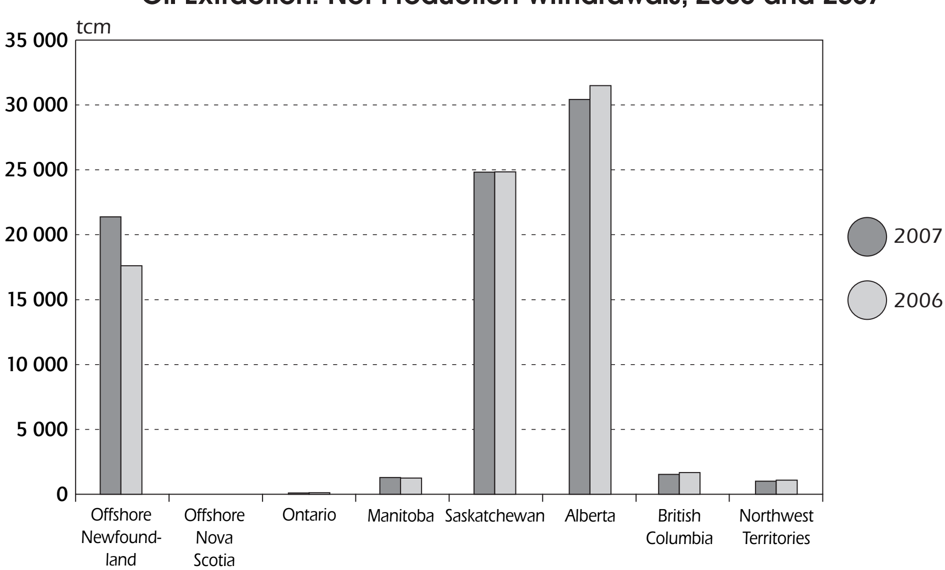
Increasing costs of environmental compliance can also add significant uncertainty to oil-sands development and reduce growth prospects. The future regulatory arrangements in North America in relation to carbon emissions and carbon capture and storage (CCS) are especially relevant.

MAIN PRODUCING REGIONS

Canadian provinces and the Northwest Territories produce oil, but only three – Newfoundland and Labrador, Saskatchewan, and Alberta – do so in significant quantities. In 2008, production in these three provinces accounted for 97% of total Canadian crude oil production. Production in Alberta and Saskatchewan is regulated by the provinces while in Newfoundland and Labrador, the federal government and the province jointly regulate offshore production activities while the province oversees production onshore. To date, all production in Newfoundland and Labrador has been offshore. In addition, federal government jurisdiction applies to territories north of 60 degrees, aboriginal and offshore frontier areas, although the territories are taking on an increasing role in management.

Figure 30

Oil Extraction: Net Production Withdrawals, 2006 and 2007



Source: Oil and Gas Extraction 2007, Statistics Canada.

ALBERTA

Alberta is Canada's principal producer of oil and petroleum products, producing approximately 68% of total Canadian oil production. Conventional crude oil production averaged 503 000 barrels a day (b/d) in 2008. Total marketable oil-sands (non-upgraded) bitumen and synthetic oil production in 2007 and 2008 was about 1.23 mb/d. Alberta exported about 1.4 mb/d of oil to United States markets in 2008, slightly more than in 2007 and over 40% more than in 2000. In 2008, Alberta's conventional crude oil production (not including oil-sands, pentanes and condensates) represented 27% of the province's total crude and equivalent production and 19% of Canada's total crude and equivalent production.

The Alberta Department of Energy ensures the environmentally sustainable development of provincially owned energy and mineral resources and the assessment and collection of non-renewable resource revenues in the form of royalties, freehold mineral taxes, rentals and bonuses. The Department promotes responsible development of Alberta's energy and mineral resources, recommends and implements energy- and mineral-related policy, grants rights for exploration and development to industry, and establishes and administers fiscal regimes and royalty systems.

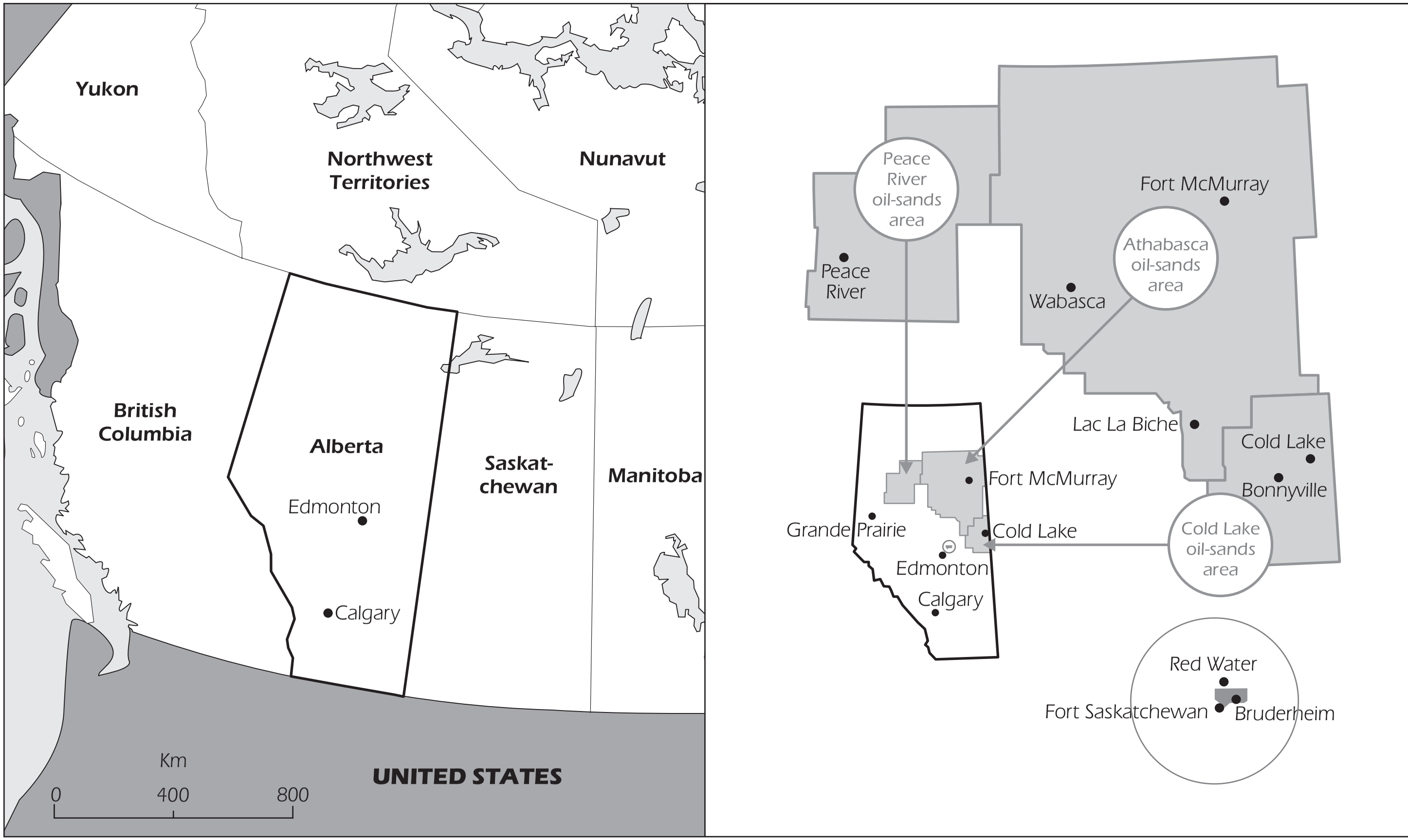
The royalty formula for conventional oil production in Alberta is based on the sum of two components: the price component (rp) based on the quality of oil and the quantity component (rq) based on the level of production. The royalty rate is applied on a sliding scale which is designed to accommodate a wide range of price and production combinations. Generally, heavier oil has a lower royalty rate than lighter oil, reflecting its lower product value. Oil-sands royalty rates are also applied on a sliding scale and are based on prices of West Texas Intermediate (WTI) crude oil in Canadian dollars. Different royalty rates are applied to projects in the "pre-payout" and "post-payout" parts of the overall formula. An oil-sands project is deemed to reach payout when its cumulative revenues equal or exceed its cumulative costs and return allowance.

- During the "pre-payout" phase, the sliding rate royalty equals to 1% of project gross revenue when WTI price is at CAD 55 per barrel and increases to the maximum of 9% of project gross revenue when WTI price reaches CAD 120 per barrel.
- During the "post-payout" phase, the greater of the gross project revenue times the gross royalty rate, or the net revenue times the net revenue royalty rate applies. The net royalty rates increase from 25% (WTI at CAD 55 per barrel) to the maximum of 40% (WTI at CAD 120 per barrel).

In response to the global economic crisis and a slow-down in conventional oil and gas drilling throughout the province, the Alberta government has provided companies drilling certain new wells after 1 January 2009 with a

Figure 31

Location of Alberta Oil-Sands Regions



The boundaries and names shown and the designations used on maps included in this publication do not imply official endorsement or acceptance by the IEA.

Source: Responsible Actions – A Plan for Alberta's Oil Sands, Government of Alberta, 2009.

one-time option of selecting new transitional royalty rates. Industry has the option of selecting the transitional rates or the Alberta Royalty Framework (ARF) rates when drilling a new natural gas or conventional oil well 1 000 to 3 500 metres in depth. An estimated 20% of all wells will be eligible for the programme.

All wells drilled between 2009 and 2013 that adopt the transitional rates will be required to shift to the ARF in January 2014. The five-year programme is aimed at encouraging the development of new drilling projects and maintaining industrial employment levels.

Along with the ARF, the Department of Energy provides a Deep Oil Exploratory Well programme. Under this programme, new field wildcat wells, new pool wildcat wells or deeper pool test wells that qualify will have their royalty reduced to zero for the first 12 months of production or until the cumulative value of the royalty on the oil equals CAD 1 million.

A stimulus package was also developed to further encourage activity in the oil and gas sector. From 1 April 2009 to 31 March 2011, wells may qualify for the New Well Royalty Reduction (NWRR) programme and the Drilling Royalty Credit (DRC) programme. The NWRR programme limits the royalty on certain wells to 5% whether calculated under the ARF or transitional royalty rates. The DRC programme provides a CAD 200 per metre royalty credit on new wells drilled on Crown or partial Crown lands.

SASKATCHEWAN

Saskatchewan is the second-largest oil producer in Canada after Alberta. The Ministry of Energy and Resources regulates the upstream oil industry on behalf of the provincial government. The province produces approximately 16% of total Canadian oil production. Crude oil production in 2008 averaged just over 440 000 barrels per day, a record.

The Bakken oil formation is one of North America's most attractive oil plays and it stretches across North Dakota, Montana, southern Saskatchewan and south-west Manitoba. About one-quarter of the Bakken oil formation lies in Saskatchewan. The Bakken oil formation is one of the largest light conventional oil discoveries found in western Canada, holding at least one billion barrels of oil in place in Canada, of which up to a quarter is recoverable. In the last few years, much of the Saskatchewan's production gains have come from this area. Production from the Bakken formation is now above 15 million barrels per year. New horizontal drilling technology in combination with open-hole multi-stage fracture stimulation has made projects economic even at the low oil prices seen following the 2008 financial crisis.

Saskatchewan produces oil in four major regions: Lloydminster, Kindersley-Kerrobert, Swift Current, and Weyburn-Estevan. Heavy crude oil is produced from wells drilled in the Lloydminster and Kindersley areas. Light crude oil is located mainly in the south-east part of the province around Weyburn-Estevan, although a small amount is also produced in the Kindersley area. Medium crude oil is found in both south-east and south-west Saskatchewan. The oil-sands area extends beyond the province of Alberta. According to Oil Sands Quest, a Calgary-based oil-sands company operating within the province of Saskatchewan, there could be 50 to 60 billion barrels of bitumen in place in north-western Saskatchewan.

Conventional oil production is subject to a Crown royalty and freehold production tax regime (royalty on Crown production and tax on freehold production) that is sensitive to price, to oil production rate at a well and to type of oil. Drilling incentives are available for wells that meet the criteria for horizontal, exploratory or deep oil wells. Special tax treatments are also available for enhanced oil recovery (excluding water flood) such as CO_2 injection and thermal processes.

NEWFOUNDLAND AND LABRADOR

Newfoundland and Labrador first produced oil from the offshore in 1997. The province's three producing oil projects – Hibernia, Terra Nova and White Rose which, in 2008, represented approximately 39% of Canada's conventional light crude output – produced 342 000 barrels a day. Further development is expected to commence in the Hebron Project Area which targets first oil production by the end of 2017. Hebron has significant potential, with an estimated 400 to 700 million barrels of recoverable resources located in the project area.

The Canada Newfoundland Offshore Petroleum Board (C-NLOPB) is responsible, on behalf of the federal government and the government of Newfoundland and Labrador, for petroleum resource management in the offshore area. The government of the province has sole petroleum management authority onshore.

The provincial government is responsible for the negotiation and establishment of royalty regimes for offshore oil and gas resources. Specific royalty agreements were negotiated for the province's first two offshore oil projects – Hibernia and Terra Nova. However, in 1996 the province introduced a Generic Offshore Royalty Regime which applies to all offshore oil projects with the exception of Hibernia and Terra Nova. The royalty is comprised of a basic royalty component and a net royalty component. The basic royalty component is applied to the value of petroleum production. The net royalty is profit-based and, consequently, is progressive. The royalty system is sensitive to the costs, risks and challenges associated with exploration and development in the Newfoundland and Labrador offshore.

Box 2

Non-Conventional Oil in the Albertan Oil-Sands

A significant portion of the world's remaining oil resources are classified as non-conventional. These resources – oil-sands, extra-heavy oil and oil shale – are generally more costly to produce, though considerable progress has been made in addressing technical challenges and lowering costs. Oil-sands and extra-heavy oil resources in place worldwide together amount to around six trillion barrels, of which between one and two trillion barrels may be ultimately recoverable economically. The world's extra-heavy oil and oil-sands resources are largely concentrated in Canada (mainly in the province of Alberta) and Venezuela (in the Orinoco Belt). The oil-sands of Alberta alone have proven reserves at present of 170.4 billion barrels (crude bitumen) and an estimated 315 billion barrels of ultimate potential (recoverable). Oil-sands are naturally occurring mixtures of sand or clay, water and bitumen.

About 80% of the proven oil-sands resources (initial volume in place) in Alberta are in the Athabasca Oil Sands Area, while the remaining 20% are split between the Cold Lake Oil Sands Area and the Peace River Oil Sands Area. On the basis of geological evidence, there is also a prospect of finding additional oil in place which could raise Canada's bitumen resources up to 2.5 trillion barrels.

While bitumen exists naturally in Alberta, it must first be recovered and processed to separate it from the sand, clay and water. Several technologies exist to extract bitumen from oil-sands. Oil-sands deposits near the surface (within 75 metres) are minable and the bitumen can be extracted using hot water and caustic soda. The extracted bitumen needs to be upgraded before being transported to a refinery. Upgrading is designed to alter the carbon-hydrogen ratio of the bitumen. It is accomplished using four main processes: coking to remove carbon and break large bitumen molecules into smaller parts; distillation to sort the mixture of hydrocarbon molecules into their components; catalytic conversions to help transform hydrocarbons into more valuable forms; and hydro-treating to remove sulphur and nitrogen and add hydrogen to molecules.

When the heavy hydrocarbon deposit is deeper (below 75 metres), drilling is required. When its viscosity is low enough or can be reduced enough for the oil to flow to the surface, long horizontal, vertical, or multi-lateral wells are used to maximise well-bore contact with the reservoir. The main drawback of such conventional production techniques is the low recovery factors, typically in the range of 5% to 10%.

Much higher recovery factors can be obtained using *in situ* viscosity-reduction techniques. In situ technologies are currently used for highly viscous oils: they include cyclic steam stimulation injection (CSS) and steam-assisted gravity drainage (SAGD). Technologies being developed include vapour extraction processes, which uses hydrocarbon solvents instead of steam to increase oil mobility, the use of down-hole heaters and hybrid methods. Theoretical recovery factor of approximately 50% to 70% is predicted for SAGD and new *in situ* processes, significantly higher than with CSS (by approximately 20% to 35%). The steam-oil ratio is also lower with SAGD (two to three) than with CSS (three to four), so less water would be required. About 20% of Alberta's bitumen can be mined, while 80% requires *in situ* recovery methods. Considering the massive volume of Alberta's discovered bitumen deposits (1.7 trillion barrels), new technology could substantially increase the volume of the economically recoverable oil-sands reserves.

According to the Energy Resources Conservation Board (ERCB), crude bitumen production in 2008 was 1.3 mb/d of which 55% was obtained from surface mining operation and 45% from *in situ* operations. Crude bitumen production is forecast to increase to 3 mb/d by 2018; in 2018 mined bitumen will still account for the majority (53%) of total crude bitumen production. Of total proven recoverable oil-sands reserves, approximately 35 billion barrels can be mined and 135 billion barrels produced *in situ*. Projections of oil-sands production could be affected by the economic climate, environmental challenges, the most notable being water needs and CO_2 emissions. Even though national and international requirements continue to evolve, oil-sands projects must comply with strict provincial legislation and standards aimed at maintaining the health and integrity of Alberta's air, water, land and wildlife, including the reduction of greenhouse gas emissions.

In 2002, Alberta began taking steps to establish the first compliance carbon offset system in North America. The 2002 Alberta Climate Change Emissions Management Act (CCEMA) required large emitters to record and file statements of annual GHG emissions beginning in 2003. In 2007, Alberta became the first jurisdiction in North America to legislate GHG reductions for large industrial facilities. Any facility, including oil-sands, that emits more than 100 000 tonnes of GHG per year is required to reduce its emission intensity by 12% below 2003-2005 levels starting in 2007. Facilities that fail to meet this target have the option of buying Alberta-based carbon offsets, or paying the Climate Change and Emissions Management Fund CAD 15 for each tonne that exceeds reduction targets. The Fund supports projects and technologies aimed at reducing GHG emissions in the province. Measures implemented by Alberta are expected to reduce GHG emissions by 50% by 2050 compared to existing operational practices.

Alberta is also the first region in North America to direct dedicated funding to implement carbon capture and storage (CCS) across industrial sectors. An investment of CAD 2 billion to advance CCS projects is expected to inject up to five million tonnes of CO_2 annually beginning in 2015. In October 2009, Alberta signed Letters of Intent with Shell Canada and TransAlta Corporation – the first two companies to implement CCS technology. The federal government and the province of Alberta jointly committed to providing CAD 745 million and CAD 175 million, respectively in funding to implement Shell's Quest Project, a major commercial-scale CCS project in Alberta's Industrial Heartland near Fort Saskatchewan, over the next 15 years. Alberta's public investment in TransAlta's Project Pioneer at the Keephills 3 plant west of Edmonton will total CAD 431 million over the next 15 years. Alberta Environment is providing an additional CAD 5 million to the project through the Alberta EcoTrust Fund, and the government of Canada is contributing CAD 343 million through the Clean Energy Fund and federal ecoENERGY Technology Initiative.

Strict limits are placed on industry's water use through a Water Management Framework (WMF) for the Lower Athabasca River. This framework is one of the most protective policies to apply to year-round water withdrawals in a northern climate anywhere in the world. Strict water monitoring is also maintained through the Regional Aquatics Monitoring Program (RAMP). RAMP is a community-based environmental monitoring programme that specifically assesses the health of rivers and lakes in the oil-sands region of north-eastern Alberta.

In February 2009, the government of Alberta released a comprehensive 20-year strategic plan for Alberta's oil-sands with the aim of reducing the environmental footprint, optimising economic growth, and increasing the quality of life in Alberta's oil-sands regions. The government of Alberta's long-term vision for the oil-sands is that development occurs responsibly, sustains growth for industry and the province over the long term, and is done in a manner that enhances Albertans' quality of life.

EXTERNAL TRADE

Canada is a large and growing net exporter of crude oil, and is likely to remain so for the foreseeable future. More than half of all Canadian indigenous crude and natural gas liquids (NGL) production is exported, equivalent to over 2 mb/d in 2007 and 2008. These exports are destined almost entirely to the United States. This made Canada the largest crude oil exporter to the United States, accounting for around 20% of total United States crude imports.

Canada has a dual oil market, where crude oil is exported from the west and Atlantic offshore and crude oil is imported in the eastern and central regions. As production in the west has increased, refiners operating in central Canada

(Ontario) have increased their use of Canadian crude oil and have reduced their dependence on imports.

Eastern Canada is dependent on foreign crude oil for a large portion of its refinery production. Owing to logistics and transportation costs, Canadian refiners, mainly in Québec and the Atlantic provinces, import roughly half of their crude oil from overseas. These imports flow by tanker into Newfoundland, Nova Scotia, New Brunswick and parts of Québec, as well as into Montreal and Ontario, via the Portland pipeline and the connecting Montreal-Sarnia Enbridge Line 9 pipeline. Nonetheless, eastern Canada's level of dependence is falling as production on the east coast increases. The region also exports significant volumes of refined petroleum products to the United States.

If the eastern region were to be considered like any other IEA net-importing country, and inventories were to be measured in days of net imports, the region would be deemed to hold about 25 days of net imports of crude oil, while being a net exporter of refined petroleum products. Combined, industry-held stocks are over 80 days of net imports. Approximately 850 kb/d of oil was imported into eastern Canada in 2007 and 2008.

REGULATORY OVERSIGHT

In accordance with the terms of the Canadian Constitution, it is generally the provinces that have jurisdictional responsibilities of the resources that lie within their boundaries and are therefore responsible for oversight of the industry within their boundaries. There are, however, a number of areas of shared responsibility as there are many cases of individual, corporate, First Nations', federal (national parks) ownership of energy and mineral rights within specific land areas, and federal responsibilities under the Canadian Environmental Protection Act.

NATIONAL ENERGY BOARD

The National Energy Board (NEB) is an independent federal agency established in 1959 by the Parliament of Canada to regulate international and interprovincial aspects of the oil, gas and electric utility industries; therefore, interprovincial and international oil and gas pipelines are regulated by the National Energy Board. Additions to existing pipeline systems under federal jurisdiction also require the NEB's approval before they may be built. The NEB regulates pipeline tolls and tariffs under its jurisdiction to ensure they are just and reasonable and that there is no undue discrimination in tariffs or services.

Pipelines under the NEB's jurisdiction are divided into two groups: Group 1 consists of ten major oil and gas pipeline companies and Group 2 encompasses the remaining smaller companies. This grouping tailors the degree of financial regulation to the extent of the public interest in a company's operations. To reduce the regulatory burden on smaller companies, the NEB regulates three of the Group 1 pipelines and all of the Group 2 companies on a complaint basis. Under the complaint basis of regulation, the parties are encouraged to work out any problems with the pipeline company. If this is unsuccessful, a complaint may be filed with the NEB.

The NEB also authorises oil exports by issuing short-term orders for periods of less than one year for light crude oil and of less than two years for heavy crude oil. These exports occur under short-term orders according to the characteristics of the oil market. The NEB does not regulate oil imports.

In addition, the NEB regulates frontier lands and offshore areas not covered by provincial/federal management agreements. Its responsibilities include the regulation of oil and gas exploration, development and production, enhancing worker safety, and protecting the environment in these regions.

FEDERAL LEGISLATION AND REGULATIONS

Canada has a set of four principal acts which govern oil and gas activities in the offshore:

The *Canada Petroleum Resources Act* (CPRA) governs the lease of federally owned oil and gas rights on "frontier lands" to oil and gas companies that wish to find and produce oil and gas. Frontier lands include the "territorial sea" (12 nautical miles beyond the low water mark of the outer coastline), and the "continental shelf" (beyond the territorial sea).

The *Canada Oil and Gas Operations Act* (COGOA) established the regulatory regime for the exploration, production, processing and transportation of oil and gas in marine areas controlled by the federal government. These areas include the "territorial sea" and the "continental shelf". They do not include areas controlled by provincial governments.

The *Canada-Newfoundland Atlantic Accord Implementation Act* and the *Canada-Nova Scotia Offshore Petroleum Resources Accord Implementation Act*, otherwise known as the Accord Acts, implement agreements between the federal and provincial governments relating to offshore petroleum resources. The Accord Acts mirror both the COGOA and CPRA, and outline the shared management of oil and gas resources in the offshore, revenue-sharing, and establishes the respective offshore regulatory boards.

OTHER AGENCIES AND INITIATIVES

Major Projects Management Office

The Major Projects Management Office (MPMO) was established by the government of Canada in 2007 to facilitate improvements to the regulatory process of major resource projects. Its role is to provide overarching project management and accountability for major resource projects in the federal regulatory review process, and to facilitate improvements to the regulatory system for major resource projects.

Frontier and Offshore Regulatory Renewal Initiative

The Frontier and Offshore Regulatory Renewal Initiative (FORRI) was established in 2005 to renew and modernise the regulatory framework governing Canada's frontier and offshore oil and gas sector. It is a partnership of federal, provincial and territorial government departments and regulators that are involved in frontier and offshore regulatory issues.

Northern Regulatory Improvement Initiative

Indian and Northern Affairs Canada (INAC) is the federal department charged with meeting Canada's obligations and commitments to First Nations, Inuit and Métis, and for fulfilling the federal government's constitutional responsibilities in the North.

In response to criticisms of the northern regulatory regimes, in particular that of the Northwest Territories, and to calls for change, the INAC developed the Northern Regulatory Improvement Initiative (NRII). The NRII has a twofold approach, focusing on both solid, operational-level improvements to areas of federal responsibility, while building a longer-term regulatory improvement agenda. The longer-term approach included a detailed examination of current regulatory systems for non-renewable resources in northern Canada and a process to make improvements.

In July 2008, the Report of the Minister's Special Representative for the NRII was published.[45] The report presented judgement on the status of the non-renewable resource regulatory systems in northern Canada, with a focus on the Northwest Territories (NWT), including recommendations.

The report recognised a need for a restructuring of the regulatory system in the NWT, to address the issues of complexity and capacity. The report recommends two options to restructure based on an amalgamation of the present land-use permitting and water-licensing functions under a single board for the Mackenzie Valley. The report also contains twenty-two additional improvement recommendations.

45. "The Review of the Regulatory Systems Across the North", in *Road Improvement: Report to the Honourable Chuck Strahl, Minister of Indian Affairs and Northern Development*, Indian and Northern Affairs Canada, May 2008.

In 1990, the federal government ceased to restrict acquisitions in the domestic oil industry by non-Canadian firms. This decision to remove restrictions on foreign ownership in the petroleum industry reflected, in part, trade liberalisation between Canada and its partners under the free trade agreements. Under the Canada–United States Free Trade Agreement and the North American Free Trade Agreement (NAFTA), Canada made a commitment to provide "national treatment" to American- and Mexican-owned businesses. Deregulation has increased the flow of investment in Canada's petroleum industry, facilitating its development.

Approximately half the oil industry has the majority of its capital owned by non-Canadians and a number of multinational oil companies have both upstream and downstream operations. Canadian oil resources are primarily developed and produced by more than 100 member companies represented by the Canadian Association of Petroleum Producers. In addition, the Small Explorers and Producers Association of Canada (SEPAC) represents the unique interests of emerging and smaller oil and gas companies, to the public, governments and other sectors of the energy industry. Supporting more than 450 member companies, the small explorers and producers are generally Canadian-owned and controlled.

In 2008, the top ten oil producers in Canada controlled 61% of domestic oil production. Six of these have a majority-owned by Canadians and the four largest (Suncor, CNRL, Petro-Canada, EnCana and Canadian Oil Sands Trust) account for one-third of Canadian crude oil production.[46] In August 2009, Suncor Energy Inc. completed a CAD 43 billion merger with Petro-Canada.

Government ownership in the oil industry has been progressively reduced since the early 1990s. In 2004, the federal government sold its remaining 19% interest in Petro-Canada which was created as a government-owned company in 1975. The federal government, however, retains an 8.5% ownership stake (by means of the Canada Hibernia Holding Corporation) in one project, the Hibernia Oil Project (offshore Newfoundland and Labrador).

According to the Canadian Association of Petroleum Producers (CAPP), the share of Canada's petroleum production held by foreign interests rose from 31% in 1999 to 56% in 2008. However, foreign control of Canadian petroleum production remains well below the peak level of 74% reached in 1977. To protect Canada's interests, foreign takeovers of Canadian oil and gas companies are subject to review under the Investment Canada Act.

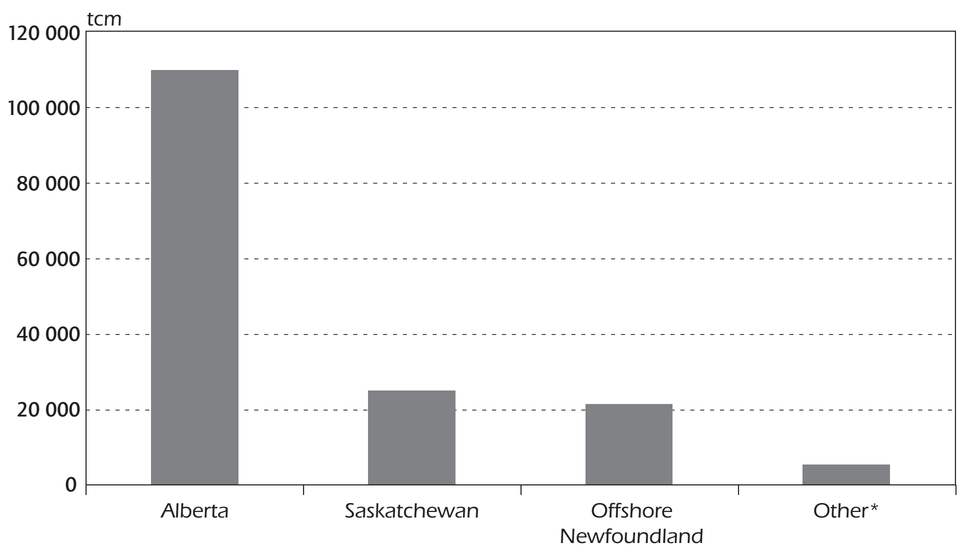
46. The Canadian Oil Sands Trust is an income trust providing an undiluted, unhedged investment opportunity in the oil-sands through their 36.74% interest in the Syncrude Project.

REFINING SECTOR

Total crude oil refining capacity stands at close to 2 mb/d. Canadian refineries have undergone significant rationalisation over the past three decades, when the number of refineries has dropped from a high of 40 in the 1970s to the 19 operating at present. Of the 19 refineries in Canada, there are 16 that manufacture the full range of petroleum products. Husky's facility in Lloydminster Alberta, and the Moose Jaw Asphalt plant in Moose Jaw, Saskatchewan, are primarily asphalt plants with limited production of other products. The Nova Chemicals facility in Sarnia, Ontario, is a petrochemical plant that also produces some distillate products. Since the early 1990s, refining capacity has been more stable and utilisation rates have been above 90% nationally for most of the last decade (with the exception of 2008/09). Generally, a 95% utilisation rate is considered optimum as it allows for normal maintenance and seasonal turnarounds.

Figure 32

Supply of Crude Oil and Equivalent by Source, 2007



* includes British Columbia, Manitoba, Northwest Territories, Offshore Nova Scotia and Ontario.

Source: Statistics Canada.

There are three main refining centres: Edmonton (Alberta), Sarnia (Ontario), and Montreal (Québec). Manitoba, Prince Edward Island and the northern territories have no refineries.

Most planned new capacity additions have fallen off the planning horizon owing to the financial downturn, shrinking margins as a result of the falling crude price, and capital availability. In particular, Shell Canada and Irving recently announced that they will not be proceeding with their respective refinery projects in southern Ontario and New Brunswick. Regulatory and economic uncertainty will continue to play into investment decisions for the refining sector in Canada.

In the short and medium term, most future changes to refining capacity or additions of conversion units will be done in response to environmental regulations pertaining to fuel quality and air emissions. The Canadian government indicates that the cumulative additional refining capacity that is currently under proposal stands at around 300 kb/d.

With bitumen production projected to increase and light crude oil production in decline, the growing trend of refinery conversion projects in Canada is likely to continue. In 2008, Petro-Canada completed the conversion of their Edmonton refinery to use exclusively oil-sands feedstock. Newfoundland and Labrador Refining Corporation (NLRC) is contemplating a new refinery at Southern Head in Placentia Bay, Newfoundland and Labrador. The proposal is for a refinery with a capacity of 300 kb/d that would serve the export market. Currently this project is stalled owing to a lack of financing.

Consumers' Co-operative Refining Limited (CCRL) has announced that it will be expanding its 100 kb/d refinery, north of Regina, Saskatchewan, by 30 kb/d. This project is under way and is expected to be completed in 2012.

STORAGE CAPACITY

Storage capacity information is not available because Canada has no publicly held stocks and does not require industry to provide this information. However, the federal government is working with the refining industry to develop mechanisms for greater transparency of inventory and other refinery-related data.

PIPELINES

Canada has approximately 70 000 km of oil and gas pipelines (Figure 33) that are regulated by the NEB.

Canada's oil pipeline capacity will need to be expanded to match increased output forecast from the oil-sands. While various pipeline expansion projects have already been completed (for example Enbridge Inc's Spearhead reversal, which opens the markets in the Midwest United States, and the Gulf of Mexico to Canadian oil-sands-derived crude oil, and Terasen Inc's expansion of its Express Pipeline system), there are a number of pipeline companies proposing new infrastructure in Canada.

The Northern Gateway Project (Gateway) is a proposal by Enbridge to construct an import/export marine terminal near Kitimat, British Columbia, with a 36-inch crude oil export pipeline and a 20-inch condensate import pipeline running 1 170 km between the terminal and Edmonton, Alberta. The westward-bound oil export pipeline will transport up to 525 kb/d of crude oil to the coast for export on tankers and the east-bound import pipeline will be capable of transporting up to 193 kb/d of condensate into the Edmonton area. In addition to the pipelines, the project includes a marine terminal capable of handling oil tankers up to 320 000 deadweight tonnes or very large crude carriers (VLCC). VLCCs will be used to export diluted bitumen primarily to the Asian market, while Suezmax vessels will be used primarily to import condensate. Enbridge is advancing the project and an application to the National Energy Board was received in December 2009.

Enbridge began construction of its Southern Lights Project, which is designed to bridge the gap between the available supply of diluents[47] from United States refineries and supply centres, and increased demand for diluents by petroleum producers in the oil-sands and heavy crude oil production regions in western Canada. The project includes construction of a new pipeline and use of some segments of the existing Enbridge pipeline that will be reversed for south-to-north diluent service. It is expected to come into service in mid-2010. A separate diluent pipeline is proposed to be built from Edmonton, Alberta, to the heavy oil-sands region in northern Alberta. The project also included the LSr Project, a 504-km, 20-inch crude oil pipeline called LSr, from Cromer, Manitoba, to Clearbrook, Minnesota, United States, which was completed in October 2008.

Enbridge's Alberta Clipper is a crude oil pipeline providing service between Hardisty, Alberta, and Superior, Wisconsin, United States. This 1 607-km segment is designed to resolve forecast capacity constraints and is expected to be in service by mid-2010. Initial capacity will be 450 kb/d, with ultimate capacity of up to 800 kb/d available.

TransCanada Corporation's 3 456-kilometres Keystone Pipeline will transport crude oil from Hardisty, Alberta to United States Midwest markets at Wood River and Patoka, Illinois and to Cushing, Oklahoma. The Canadian portion of the project involves the conversion of approximately 864 km of existing Canadian Mainline pipeline facilities from natural gas to crude oil transmission service, and construction of approximately 373 km of pipeline, pump stations and terminal facilities at Hardisty, Alberta. The United States portion of the project includes construction of approximately 2 219 km of pipeline and pump stations. The expansion of export capacity will benefit all Canadian crude oil producers through stronger netbacks associated with adequate export capacity and market diversification. It is expected to be operational in early 2010.

47. A hydrocarbon substance used to dilute crude bitumen so that it can be transported by pipeline.

There is a proposal to reverse the Sarnia-Montreal Enbridge pipeline in order to allow for crude oil to flow from Alberta all the way to Montreal. This measure is being considered by federal and Québec governments in light of the growing production in Alberta in recent years. The reversal of the pipeline would reduce the eastern provinces' dependence on crude oil imports.

Table 13

Major Crude Oil Pipelines and Capacities (January 2009)

Owner	*Name*	*From*	*To*	*Products*	*Capacity (m^3/day)*	*Length (km)*
Enbridge	Line 1	Edmonton, AB	Superior, MI	NGL, Refined products, Synthetic	37 600	1 767
Enbridge	Line 2	Edmonton, AB	Superior, MI	Condensate, Synthetic, Light crude, Medium crude	65 000	1 767
Enbridge	Line 3	Hardisty, AB	Superior, MI	Light crude, Medium crude, Heavy crude	71 000	1 592
Enbridge	Line 4	Edmonton, AB	Superior, MI	Heavy crude	106 300	1 767
Enbridge	Line 5	Superior, MI	Sarnia, ON	NGL, Condensate, Synthetic, Light crude	78 100	1 038
Enbridge	Line14/16*	Superior, MI	Chicago, IL	Condensate, Synthetic, Light crude, Medium crude, Heavy crude	49500	752
Kinder Morgan	Express	Hardisty, AB	Casper, WY	Crude oil	44 520	1 236
Kinder Morgan	Trans Mountain	Edmonton, AB	Burnaby, BC	Crude oil, Refined products	35 775	1 150
Montreal Pipeline	PMPL	Portland, MN	Montreal, QC	Crude oil	83 500	380

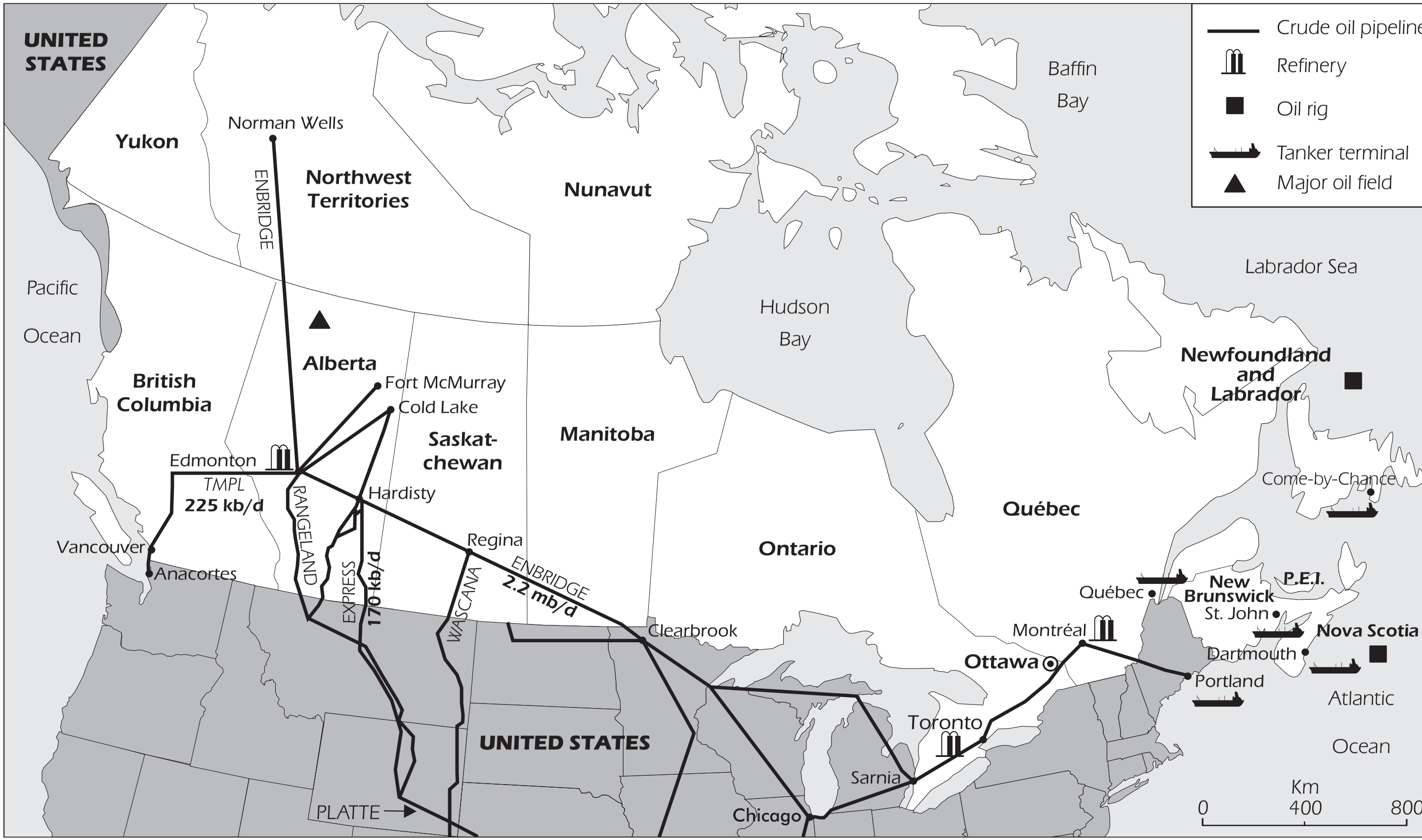
*Pipeline not in Canada but is used for domestic transit.
Source NRCan.

PORTS

Despite being a major net exporter of oil, Canada imports almost 50% of the crude oil run at domestic refineries, owing to logistics and transportation costs. The imported crude is processed in the refineries of the country's eastern provinces, notably close to the key demand centres of Ontario and Québec.

Figure 33

Oil Infrastructure



The boundaries and names shown and the designations used on maps included in this publication do not imply official endorsement or acceptance by the IEA.

Source: *Oil Supply Security*, IEA/OECD Paris, 2007.

Imports flow by tanker into Newfoundland, Nova Scotia, New Brunswick and part of Québec and by the Portland and Montreal-Sarnia Enbridge pipelines to Montreal and Ontario. Major oil offloading ports are found in the following cities: Québec City, Québec; Saint John, New Brunswick; Dartmouth, Nova Scotia; and Come-by-Chance, Newfoundland and Labrador.

EMERGENCY PREPAREDNESS

Canada's energy policy derives in part from the constitutional division of power between the federal and provincial governments, which provides both levels of government with a major role in energy policy.

Most crude oil is produced in western provinces and shipped to the east, west and south via pipelines to major domestic and export markets. Serious disruption to any of these pipelines could negatively affect supplies to certain regions (particularly the central provinces and Ontario) and could also cause environmental damage. In addition, although offshore production has increased considerably since the last in-depth review (2004), Canada's eastern provinces are still dependent on oil imports. A significant disruption of these imports could cause an emergency supply situation.

NATIONAL EMERGENCY SHARING ORGANISATION (NESO) AND TRAINING

In non-emergency times, the Oil Sands and Energy Security Division of NRCan serves as the NESO staff. In an emergency situation, when enabling legislation is activated, there is a much larger emergency organisation that could be mobilised under the Emergency Supplies Allocation Board (ESAB). This group comprises a chairman and five members. The chairman is appointed by the Governor-in-Council and reports to the Minister of Natural Resources Canada. The Board is supported by the Oil Sands and Energy Security Division of NRCan and includes personnel from oil companies (in the form of the Petroleum Industry Advisory Committee), transportation organisations, other federal government departments and the provinces (in the Provincial Advisory Committee, PAC). There have been no changes that would alter implementation of the International Energy Program (IEP) or co-ordinated emergency response mechanism (CERM) measures, and no changes to the structure are contemplated at this time.

The most recent training of NESO staff took place in 2009, involving personnel from NRCan only. NRCan staff maintains a close contact with the provincial representatives in the PAC, which was a central communications link during an IEA collective action in September 2005. A good network of communications is maintained with members of industry in order to facilitate emergency actions and monitoring.

LEGAL BASIS

The Canadian NESO operates under the Energy Supplies Emergency Act which provides the authority to the Emergency Supplies Allocation Board (ESAB) to prepare, develop, and maintain in a state of readiness, programmes to restrain demand for petroleum products and to allocate crude oil and petroleum products in a declared emergency. There have been no changes to legislation since the last in-depth (2004) review.

The legal authority to direct or ration the flow of petroleum already exists under either the Energy Supplies Emergency Act or the Emergencies Act

There is no specific federal legislation relating to CERM activities. However, most CERM activities related to demand restraint come under provincial jurisdiction. All activities relating to CERM would be handled on a voluntary basis with the full co-operation of the industry and the provinces.

EMERGENCY OIL RESERVES

As a net exporter, Canada has no IEA emergency reserve commitment and does not hold any bilateral stocks for other IEA member countries. All stocks currently held in Canada are commercially owned and oil companies are not required to hold emergency stocks in normal times. As such, they are held for operational and logistical purposes.

In the case of refineries, minimal operating requirements are to hold about 45 days (or 20 to 25 days when excluding pipeline and working volumes) of oil stocks. However, refiners in eastern Canada, which for the most part run imported crude, generally hold greater volumes than their peers in the western provinces.

However, in a declared national emergency, the ESAB would have the authority to regulate company stocks and to penalise companies for contravention of its orders under Section 41 of the Energy Supplies Emergency (ESE) Act. Under the ESE Act, Sec. 25 (d), the ESAB has the authority to regulate building, storage and disposal of stocks, including industry stocks, during a declared national emergency. The threshold level would be decided by the federal government in consultation with the oil industry at the time of an emergency. The mechanism requires monthly reports to the ESAB by each company on its stock situation.

In the event of a declared national emergency, the drawdown of commercial stocks could be carried out by oil companies under the mandatory allocation programme. Initial data submissions would be received by the NESO and, after consultation with industry through the federal government's existing Advisory Committee, a decision would be taken (including an agreement upon the level of stock drawdown required and confirmation of the timing) and the stock drawdown would be initiated. Stocks would be released into the market by companies meeting their crude oil entitlement and the product entitlements of their customers. The ESAB has the power to establish parameters for prices, as well as set prices if necessary, at the time of emergency. This sequence of events would require about two to three weeks.

As the federal government's emergency policy emphasises market mechanisms and would only use heavy allocation actions as measures of last resort, it is unlikely that commercial stocks would be directed in such a manner.

As part of its jurisdiction rights, each Canadian province is responsible for setting product specifications on motor fuels within its borders. With environmental concerns in mind, some provinces have imposed stricter specifications than others, notably in terms of sulphur emissions. However, in case of an oil supply disruption, it is important to ensure that oil products can flow as easily as possible between different regions, in order to alleviate any localised disruptions. In this regard, a greater level of harmonisation of standards – across both Canada and the United States – would greatly improve emergency supply flows within the continent. Provinces could allow for a loosening of motor fuels specifications in the event of an oil supply crisis.

Canada is a large oil producer, and it also has significant port capacity on both the Atlantic and Pacific coasts. As such, the country as a whole is well positioned with regard to accessing oil supplies. However, some of the more landlocked Midwestern provinces do not have well-diversified supplies of oil and products. The temporary closure of a pipeline or even a local refinery could have a significant impact on the oil product supplies of these provinces.

The Canadian government is currently in the process of re-evaluating its stockholding and response capabilities in the event of domestic or international disruption, as well as options to mitigate the risks of any type of disruption. In addition to a number of other options, it is re-evaluating the possibility of strategic reserves for Canada. Nevertheless, all previous analysis has led to the conclusion that, owing to the geographically disperse nature of the country, the costs of a crude oil strategic reserve would be likely to outweigh the benefit.

OIL DEMAND RESTRAINT

Policy and Legal Instruments

In a co-ordinated emergency response mechanism (CERM) type action, and in the absence of the government of Canada declaring a national emergency, activities related to demand restraint come under provincial jurisdiction. A federal-provincial co-ordinating committee would pool the knowledge and information related to demand restraint measures among the federal and provincial representatives. It is important to note that without the implementation of the International Energy Program (IEP) (and thus the declaration of a national emergency), the federal government does not have legal authority in place to implement demand restraint measures.

However, all activities would be determined by each province with the full co-operation of the industry. At federal level, activities would include media campaigns to encourage voluntary consumption reductions and the prevention of hoarding. Theoretically, in a declared emergency under the auspices of the IEP, demand could be restrained mandatorily at federal level, by means of implementation of the crude oil and products allocation programme. Further demand restraint measures would be implemented by the provinces and territories to complement actions imposed by the federal government. However, these actions require the declaration of a national emergency.

Specific procedures for demand restraint are described in the Energy Supplies Emergency Act. Additionally, the Emergencies Act, established in 1988, provides a more flexible approach to how demand restraint is achieved, allowing the Governor-in-Council the "requisition, use or disposal" of energy commodities. In the cases of either of these legal instruments, an energy-related national emergency would first need to be declared by the Governor-in-Council.

Canada indicates that demand restraint is the primary tool to which it would resort in the event of an IEA collective action under the CERM. Nonetheless, the scope for the federal government's demand restraint programme under the CERM is limited, since the executive powers to impose such restrictions under the CERM reside with the provinces. The Federal Government's Demand Restraint Program would consist of several phases.

Phase 1 of the programme would consist of an extensive public education and awareness campaign throughout the federal government to increase energy efficiency and to reduce unnecessary use of petroleum. Phase 2 would involve a target of 5% to 7% mandatory oil consumption reduction across the federal government via the issuance of a Treasury Board directive. Additional measures, depending on the severity of a shortage, could consist of car-pooling for federal employees, compressed work weeks with teleworking, encouraging mass transit possibly through fair subsidies, and continuing to work with provinces on reduced speed limits, driving restrictions, and other oil demand reduction efforts along the lines of *Saving Oil in a Hurry.*[48]

Measures and Procedures

During a disruption of oil supply, and under a declared national emergency, the ESAB would activate allocation plans to ensure that crude oil and products are distributed fairly and equitably to all citizens.

48. *Saving Oil in a Hurry*, IEA/OECD Paris, 2005.

The Crude Oil Allocation Program apportions available crude oil from offshore and domestic sources to refineries throughout Canada, and can be used to free up crude for export, in the case of a supply obligation in the IEP's emergency sharing system.

The Petroleum Products Allocation Program controls the volume of products that refiners and other major suppliers may sell to wholesale customers. Rationing of gasoline and diesel fuel through coupons can be implemented as a last resort.

Demand restraint in petroleum products could be achieved through the issue of allocation factors which are to be applied to three priority categories of historical sales. The allocation factors are designed to limit current sales at wholesale level in each of these categories of end-use to a proportion of historical sales. The effects would be felt immediately. Progress would be monitored on a monthly basis.

The allocation factors would be issued for three basic priorities of use:

- health, welfare and security of Canadians (hospital services, fire and police protection, national defence or public transit);
- economic stability (most industrial and commercial activities, including public utilities, postal services, taxis and road maintenance); and
- discretionary activities related to the maintenance of the standard of living (supplies of gasoline at the service stations and of fuels for heating commercial buildings).

In addition to restraining sales of products, crude oil intake in refineries could be reduced to complement and match permissible product requirements. This can be implemented within days of a declared emergency and submission of data from industry.

It would take up to 60 days after the declaration of an emergency to fully implement the mandatory products allocation and initially issue product entitlements. The federal government understands that the effects of mandatory allocation would be immediate and equal to the demand restraint imposed each month.

In addition, a public information programme has been developed to communicate relevant information to the public through the media.

The decision process for activating the programme is described in the Energy Supplies Emergency Act and would involve recommendations from the Emergency Supplies Allocation Board to the Governor-in-Council (the Cabinet of the federal government). This process was tested in the preparations for year 2000.

Volumetric Savings and Monitoring

No recent studies have been conducted on estimated volumetric savings from demand restraint measures. Likewise, no estimates are available on the costs of implementing these measures. Such estimates would need to be developed in the provinces, where the bulk of demand restraint measures would be implemented.

In the event of a declared national emergency, the allocation programme would restrict the amount of crude oil processed by refineries and the product sales at the wholesale level. In this case, volumetric savings would be known once the decision on demand restraint is taken by the ESAB.

Because of the delay in obtaining accurate sales data needed to measure the responsiveness of demand until statistics are compiled and published by Statistics Canada, the federal government is unable to accurately measure the responsiveness of voluntary demand restraint until data become available three months later.

There have not been any studies performed on Canada's ability to rely on policy-driven demand restraint. There are numerous methodological and practical issues associated with attempting to disentangle the impacts of policy-driven demand restraint from the price-driven reduction in demand that would probably occur in the event of a crisis.

Surge Oil Production

Surge production capacity is relatively limited, as producers generally maximise rates. Moreover, surge production can only be achieved over a short period of time (months), as there is risk of damaging wells and reservoirs, particularly if maintained for more than a few weeks or months. Furthermore, the federal government has little control over surge production because most oil resources are under provincial jurisdiction. It should be noted, however, that Canada did use surge production as one of its response measures following hurricanes Katrina and Rita in 2005.

In times of extreme emergency, the Federal Emergencies Act gives authority for oil production control to the federal government. It is estimated that this intervention process would take a minimum of two weeks.

Fuel Switching

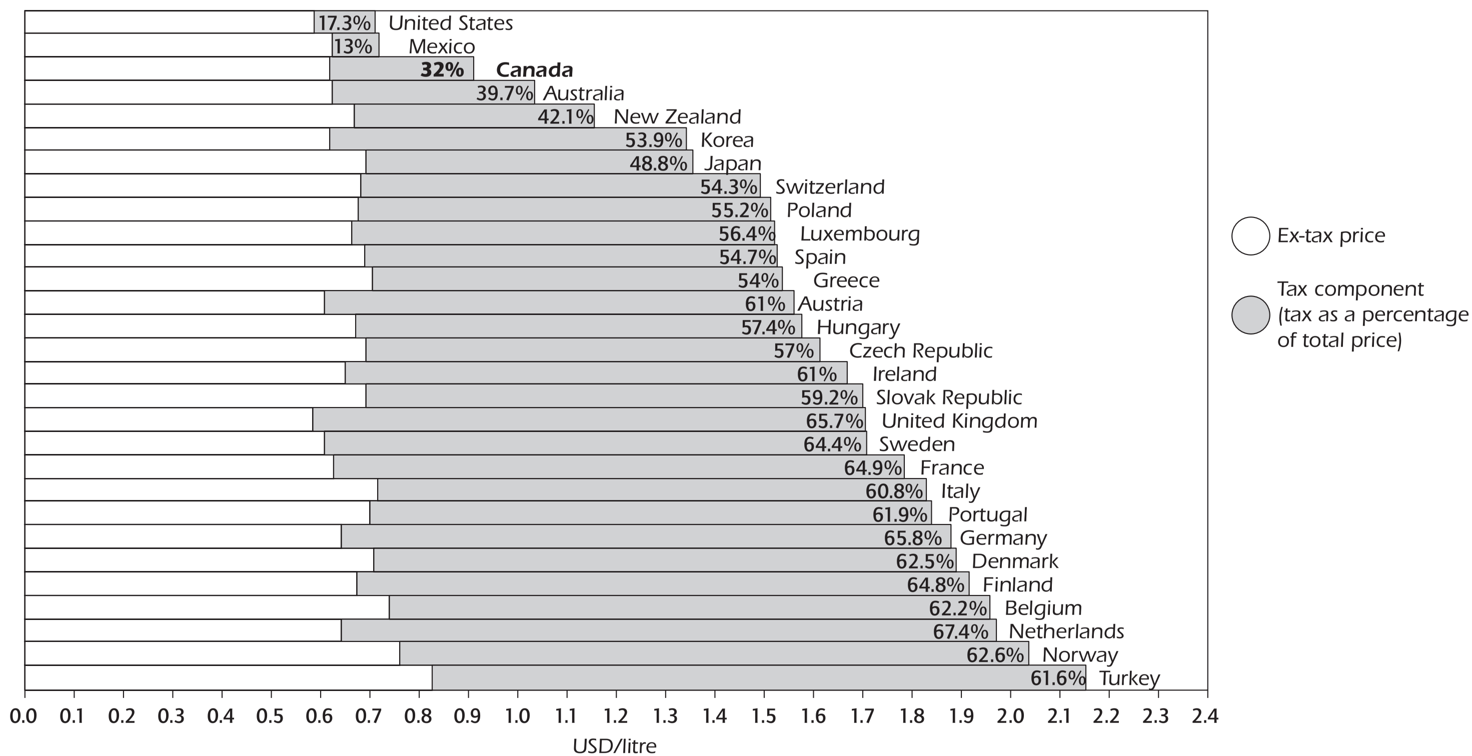
There are no fuel switching policies in place in Canada and it is understood that there is little fuel switching capability in Canada.

TAXES AND PRICES

Since January 1991, a federal goods and services tax (GST) is levied on all petroleum products. Initially established at 7%, it was reduced to 6% in July 2006, and to 5% in January 2008. There are also excise taxes, which vary from product to product. Provinces also apply their own sales and consumption taxes, which vary across provinces.

Figure 34

OECD Unleaded Gasoline Prices and Taxes, Third Quarter 2009

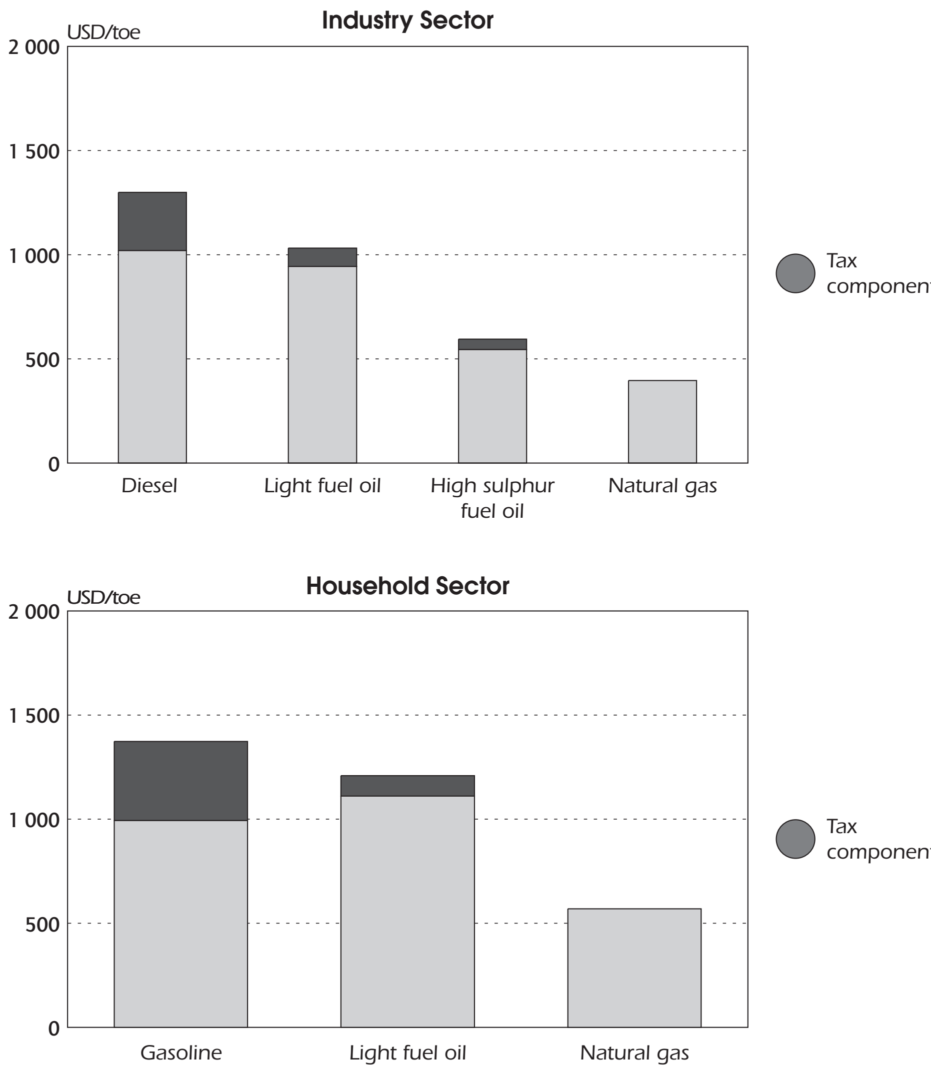


Source: *Energy Prices and Taxes*, IEA/OECD Paris, 2009.

Following a brief period of regulation (from the 1970s to the early 1980s), the Canadian federal government is committed to a market-based approach to determine prices for crude oil and fuels such as gasoline. While some provinces have opted to regulate gasoline and other fuel prices, this approach has not resulted in reduced prices for consumers in these jurisdictions. In general, the purpose of price regulation in some provinces is to provide price stability.

Figure 35

Fuel Prices, 2008



Source: *Energy Prices and Taxes*, IEA/OECD Paris, 2009.

With the exception of a national emergency, the federal government has no jurisdiction over the direct regulation of retail fuel prices. Under the Canadian Constitution, the provinces have that authority. Some provinces choose not to exercise their regulatory authority, relying instead on market forces. Others, including Prince Edward Island, Newfoundland and Labrador, Nova Scotia, New Brunswick and Québec, regulate prices in some way.

CRITIQUE

Canada is a country endowed with large and geographically dispersed petroleum resources. Oil production from traditional conventional fields is in decline and future production will increasingly be dominated by new sources in frontier lands and unconventional sources, especially the oil-sands of Alberta. In general, Canada is managing the challenges related to its petroleum activity in a sound way, as it does in the natural gas market.

The Constitution of Canada gives the provinces a large degree of autonomy. The provincial legislatures have power over direct taxation in the provinces for their own purposes and their natural resources. The federal government shares responsibility with the provinces in relation to offshore activity and with the territories in relation to resources in the North. Stakeholders in frontier lands of the North have a voice and are involved in federal government decision-making processes with regard to petroleum activity in their regions. This degree of autonomy, however, also represents a challenge for Canadian resource management.

There are a number of strategic investment issues facing the oil industry: sustainable development of the oil-sands; exploration and development in the North; further development offshore and in the Arctic region; the global economic crisis; and access to international markets beyond the United States. The federal government should continue to be alert to these issues and keep under review the impact that taxation and regulatory policies may have on the outcome. However, it should also maintain its broad policy approach in which investment decisions are left to the private sector.

One of the greatest challenges facing Canada is to continue to develop its vast unconventional oil resources in a sustainable manner. In this regard, the forecast increase in production from the oil-sands of Alberta poses the greatest test. Main regulatory responsibility lies with the province of Alberta but the federal government also has an important role to play. Within Canada, oil-sands production accounts for 5% of GHG emissions and if the oil-sands are to continue to develop as forecast, GHG emissions are expected to grow significantly. Given the increasing importance of climate-change concerns, both at national and international levels, Canada must take care to develop this resource without a disproportionate increase in emissions and without incurring excessive emissions penalties. Furthermore, oil refining is also recognised as a source of emissions and international pressure to reduce emissions from the sector may also have an impact on the ability of the industry to satisfy domestic demand.

Notwithstanding the matter of emissions from oil-sands production there are concerns in relation to post-mining reclamation and tailing ponds. Tailings management remains one of the most difficult challenges for the sector to address. Tailings are the waste water residues from the oil-sands extraction process. They include a mixture of water, sand, clay, some residual bitumen, organic compounds and trace metals, including mercury, contained in vast ponds or settling basins. Unregulated and unconstrained tailing ponds pose a potential health risk. In response, the producers, the government of Alberta and the federal government have invested heavily in tailings-related research and development. Research is also focused on reducing the amount of energy consumed during the production process. Sound policy and legislation will further minimise the risks of development to wildlife and the environment. The establishment of the Oil Sands Sustainable Development Secretariat by the Alberta government in 2007, to address a broad range of concerns related to the exploitation of the oil-sands, is also a welcome step. The publication of the *Responsible Actions: A Plan for Alberta's Oil Sands* document in 2009 builds on this progress. The document outlines an integrated approach for all levels of government, for industry, and for communities to address the economic, social and environmental challenges and opportunities in the oil-sands regions, and recognises that the federal government also has a role to play on matters of common jurisdiction or interest.

Elsewhere in Canada, the regulatory framework in potential oil-producing regions appears complex. This is further complicated by the requirement to negotiate and settle aboriginal land claims. A repeated criticism is that the outcomes of the energy project approval process are unpredictable. The establishment of the Major Projects Management Office is a very progressive step towards a more predictable and timely review process. As a general principle, the aim should be that environmental evaluation by all regulatory bodies should be carried out on the basis of a single environmental assessment. Nonetheless, the mandate of the MPMO needs to be strengthened by placing it on a sound legislative basis and by, ensuring that it has adequate resources to carry out its functions in an efficient manner.

A related uncertainty is the matter of First Nations, Inuit and Métis land claims, in particular in the North. In 2004, Supreme Court of Canada affirmed the existence of a legal duty on the Crown to consult and, in certain circumstances, accommodate asserted aboriginal interests on an interim basis pending final resolution by treaty or otherwise.[49] Since then, aboriginal consultations have

49. Supreme Court of Canada decisions in Haida Nation vs British Columbia (Minister of Forests) and Weyerhaeuser ("Haida") and in Ringstad vs Taku River Tlingit ("Taku River") of 18 November 2004.

delayed several significant energy projects and streamlining the process has proven difficult. In this regard, the Northern Regulatory Improvement Initiative is an important initiative to improve the regulatory processes in the northern territories of the Yukon, Nunavut and the Northwest Territories. Once more, the federal government should build on this initiative and increase its focus on improving the regulatory regimes, particularly in the Northern Territories, for example by simplifying regulatory processes and reducing the number of regulatory bodies involved.

There are several areas under federal or joint federal/provincial jurisdictions where there are moratoriums on petroleum activity (offshore British Columbia, Georges Bank, Southampton Island and Coats Island). The areas now closed for petroleum activity may contain substantial petroleum resources, especially in the areas offshore British Columbia (BC). At the same time, the seismic data are outdated and incomplete, and there would be a considerable time lag between the time of a possible future decision to open an area for petroleum activity and the time petroleum production from the area starts.

A federal review process regarding petroleum activity offshore British Colombia was undertaken in 2003/04 but it did not result in any changes to the moratorium. Technological development and improved knowledge about the environment and natural resources can nonetheless ensure that petroleum activity that, in the past, was considered unsafe may become possible. Taking this into account, combined with long lead times and the potential for considerable additional resources, the federal government should continue to focus on whether it is possible to have petroleum activity in these areas in a sound and sustainable manner. This should be done through filling knowledge gaps and improving necessary data, especially those relating to estimates of petroleum resources, in order to prepare for well-founded decisions regarding petroleum activities in these areas.

Canada is hugely reliant on the United States as an export market for oil and gas. In the recent past, shrinking demand as a result of the global economic crisis and uncertainty about the future treatment of oil-sands-related imports under climate change regulation are undermining confidence in forecast levels of Canadian exports to the United States. Policy makers and industry must start to focus on identifying new export markets and the infrastructure needed to access these markets. Proposals for the Northern Gateway pipeline, and an associated tanker port at Kitimat, British Columbia, to facilitate expansion of exports to Asia and other offshore markets, are evidence that project developers have started to look beyond the United States. There may be a greater role for the federal government in exploring the potential for even greater volumes of exports to Asia and other offshore markets from Canadian ports and refineries.

An additional problem is the increasing trend of cancelled or delayed projects, particularly in relation to bitumen upgrader developments in Alberta and refinery expansion projects elsewhere. This is happening at a time when production of bitumen from Alberta's oil-sands is expected to grow, albeit at a slower pace than forecast in the past. This poses challenges for the pipeline industry, which needs to make long-term plans when adding pipeline capacity. Care must be taken to ensure that Canadian producers have access to adequate refinery, pipeline and port capacity in the longer term.

As regards energy security, the main risks of supply shortages in Canada relate primarily to refined products rather than crude oil. This is an issue of concern in landlocked and relatively isolated regions of both the west and east of the country. In this regard, the imposition of an obligation on industry to hold additional stocks of refined products as emergency reserves may be an effective and cost-efficient way of reducing Canada's energy security risks. There may be other options, such as improving cross-border efficiency of refined products transport during times of crisis.

RECOMMENDATIONS

The government of Canada should:

- *Increase its focus on improving the regulatory regimes for oil and gas exploration and production in the northern territories, making them simpler and more predictable.*
- *Strengthen the role of the Major Projects Management Office by providing it with a legislative mandate.*
- *Continue to collaborate with the government of Alberta in relation to the sustainable development of the oil-sands.*
- *Work in partnership with the petroleum industry in exploring new opportunities for exports to Asia and elsewhere, and ensuring that capacity is available to meet longer-term forecasts of demand.*
- *Collect additional geological and environmental data to facilitate informed decisions on whether to open new areas for petroleum activity.*
- *Consider placing an obligation on industry to hold additional barrels of refined products.*

ELECTRICITY

Canada is the world's second-largest producer of hydroelectricity, which accounted for 58% of Canada's electricity production in 2007. Canada produced 639.8 TWh of electricity in 2008, 57.7 TWh of which was exported to the nearby United States. Other sources of electricity include nuclear, coal, natural gas and small volumes of non-hydro renewable energy sources. Production, trade and energy sources vary greatly throughout the provinces and territories. The structure of the electricity sector has been changing over the past decade and, in most provinces, there has been a move from vertically integrated utilities (often provincial Crown corporations) to various degrees of market liberalisation although market design and regulation differ from province to province.

SUPPLY AND DEMAND

Production of electricity in 2008 was greater than in 2007 (617 TWh) and 2006 (592 TWh). Electricity is generated from a reasonably diversified mix of sources. The majority of supply came from hydropower, 372 TWh or 58%, while nuclear, coal and, to a lesser extent, natural gas provided the majority of remaining production. In 2008, coal contributed about 100 TWh (16%), nuclear power 94 TWh (15%), and natural gas 43 TWh (7%). Small volumes of electricity were produced from oil and combustible renewables and waste while other non-hydro renewables made a negligible contribution. Output by energy source varied greatly from province to province. Total hydropower capacity at the end of 2007 stood at 73.4 GW or 59% of total capacity.

Table 14

Generation by Fuel and Sector, Ownership and Capacity Factors, 2007

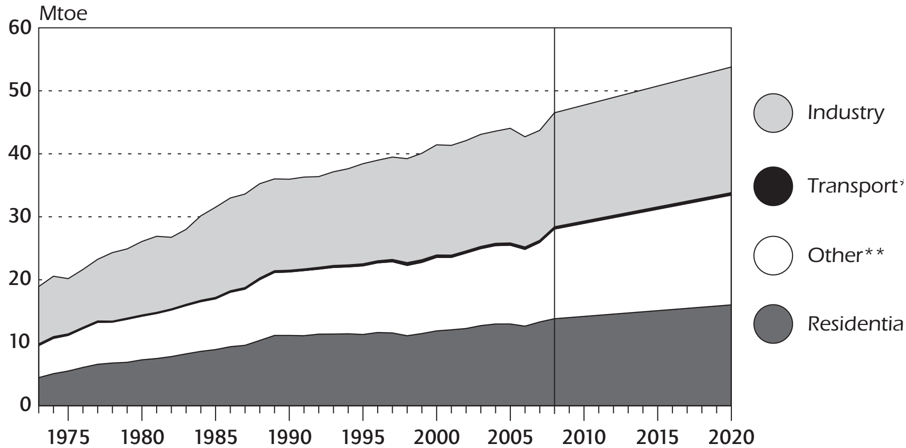
	Utilities (public and private) (MW)	*Industries (MW)*	*Total (MW)*	*Capacity factor (%)*
Hydro	68 393	5 043	73 436	57
Coal	16 179	0	16 179	76
Nuclear	13 345	0	13 345	75
Natural gas	7 429	2 169	9 598	45
Petroleum	7 759	64	7 823	N/A
Wind and tidal	1 599	1	1 600	21
Other thermal	1 153	1 106	2 259	–

Source: NRCan.

In 2007, total final consumption of electricity was 538.8 TWh, an increase of 2.7% when compared to consumption in 2006. The industrial, residential and commercial sectors account for 40%, 30% and 27% of electricity consumption. Peak electricity demand typically occurs during winter months with the exception of Ontario. Over the period 2005 to 2020, electricity demand is expected to grow by 1.3 % annually.

Figure 36

Final Consumption of Electricity by Sector, 1973 to 2020



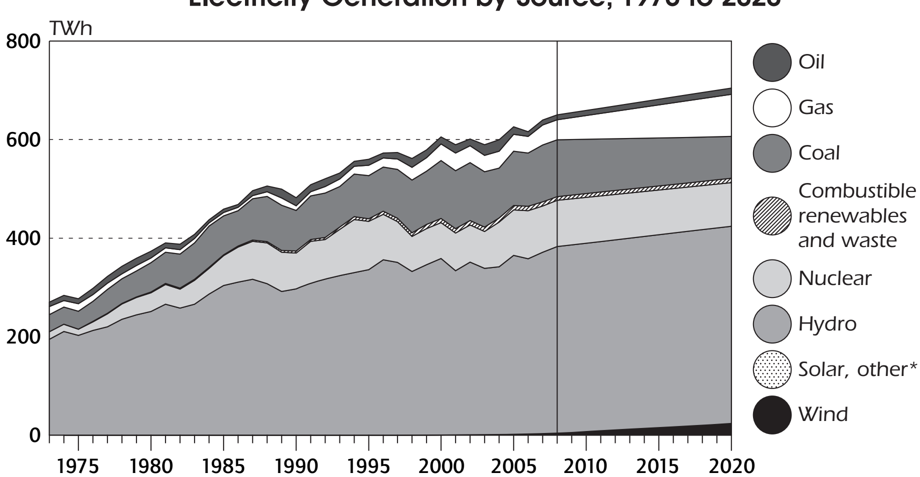
* negligible.

** includes commercial, public service, agricultural, fishing and other non-specified sectors.

Sources: *Energy Balances of OECD Countries,* IEA/OECD Paris, 2009 and country submission.

Figure 37

Electricity Generation by Source, 1973 to 2020



* other includes tide and wave (negligible).

Sources: *Energy Balances of OECD Countries,* IEA/OECD Paris, 2009 and country submission.

Canada is a net exporter of electricity to the United States; however, some regions of Canada also import less expensive power off-peak, and save water that can be used to generate electricity when prices are higher in their own market or in the United States. In 2007, net exports of electricity to the United States were 29.6 TWh.

Table 15

Generating Capacity and Plants under Construction (October 2008)

Name	*Province*	*Owner*	*Fuel type*	*Capacity*
Keephills 3	Alberta	TransAlta and EPCOR	Coal	450 MW
The Crossfield Energy Centre	Alberta	ENMAX	Natural gas	120 MW
Revelstoke Dam and Generating Station	British Columbia	BC Hydro	Hydro	500 MW addition
East Toba and Montrose	British Columbia	Plutonic Power Corp.	Run-of-river hydro	196 MW
Wuskwatim	Manitoba	Manitoba Hydro	Hydro	200 MW
The Thorold Cogeneration Project	Ontario	Thorold CoGen L.P.	Natural gas	305 MW
Halton Hills Generating Station	Ontario	TransCanada Energy	Natural gas	683 MW
Hound Chute Generating Station	Ontario	Ontario Power Generation	Hydro	9 MW
Healey Falls Generating Station	Ontario	Ontario Power Generation	Hydro	6 MW
Upper Mattagami Generating Station	Ontario	Ontario Power Generation	Hydro	34 MW
Eastmain-1-A Powerhouse	Québec	Hydro-Québec	Hydro	768 MW
La Sarcelle	Québec	Hydro-Québec	Hydro	150 MW
Eastmain-1 Development	Québec	Hydro-Québec	Hydro	480 MW
Péribonka	Québec	Hydro-Québec	Hydro	385 MW
Chute-Allard et des Rapides-des-Coeurs	Québec	Hydro-Québec	Hydro	138 MW
La Romaine	Québec	Hydro-Québec	Hydro	1550 MW

Source: NRCan.

INDUSTRY STRUCTURE

The Canadian electricity system is part of an integrated North American electricity grid. Under the terms of the Constitution, provinces have ownership over the natural resources that lie within their boundaries, including electrical energy, and thus regulatory oversight rests primarily within the jurisdiction of the provinces. Two areas where the federal government does hold authority in regard to electricity are trans-border and nuclear power-related activities. The National Energy Board (NEB) is responsible for regulating the construction and operation of international power lines and the permitting of international electricity exports. In addition, the NEB also has latent authorities surrounding interprovincial power lines. The nuclear power sector falls under the jurisdiction of the Canadian Nuclear Safety Commission.

In most provinces, the electricity industry is highly integrated with the bulk of generation, transmission and distribution services provided by a few dominant utilities. Although some of these are privately owned, most are Crown corporations owned by the provincial governments. In some cases, relatively small generators also exist, but rarely in direct competition with a Crown corporation.

Industry structure varies from province to province. In many cases the previously integrated utilities are increasingly becoming functionally unbundled to accommodate the introduction of wholesale competition. In several provinces, however, the various components are structurally distinct. For example, in Newfoundland and Labrador, generation/transmission and distribution/retail are vested in wholly separate entities. Most notably, in the two provinces which have moved to full retail competition (Ontario and Alberta) there is a great diversity of structural models with functions for the most part unbundled. Key features of Ontario's hybrid market model include the Ontario Power Authority contracting for supply, integrated system planning, and regulated pricing for much of Ontario's generation and load. As Ontario's supply situation improves, it is expected that elements of the hybrid model will gradually be modified or replaced, and that a more classically competitive market will emerge. In other provinces, parts of the industry are privately owned but provincial Crown corporations remain dominant in the generation and transmission sectors of the industry. Municipal ownership is prominent in several places, for example in Ontario where utilities such as Toronto Hydro and Hydro Ottawa are municipally owned. In Alberta, some municipalities have maintained ownership of their local distribution utility facilities, while also setting up municipally owned generation companies to compete in the open wholesale market.

Ontario and Alberta together account for around one-third of Canadian power consumption and enjoy full wholesale and retail competition. Most other provinces have moved, or are moving, to some form of wholesale competition. Below is a brief description of the industry structure in the provinces and territories.

STRUCTURE IN THE PROVINCES AND TERRITORIES

Alberta

Coal generation is the dominant source of electricity generation in Alberta; coal-fired plants make up almost 50% of the Province's total generating capacity, while natural gas accounts for about 40%. The electricity system is owned and operated by a combination of privately owned and municipally owned companies. Under the present structure derived from the Electric Utilities Act, the generation component of the system is competitive while the transmission and distribution functions are rate-regulated. Generators sell their power through a competitive market operated by the Alberta Electric System Operator (AESO).

All electricity traded in Alberta is sold through the wholesale pool, and it determines the spot price for electricity for every hour of the day. A day ahead, generators submit a schedule for each hour indicating the prices at which they will offer different quantities of electricity. The System Controller, a function at the AESO, sorts offers by price to determine the merit order. Each day, the System Controller moves up and down the merit order to dispatch supply as electricity demand changes. The price of the marginal block – the last offer that must be dispatched to meet demand – sets the system marginal price (SMP) each minute. At the end of the hour, a time-weighted average of the marginal prices is used to calculate the pool price for that hour. There are different electricity products, with different rates, terms and services, and some will suit Albertans' needs and budgets better than others.

The AESO is the independent system operator, which is responsible for the safe, reliable operation and planning of the Alberta Interconnected Electric System (AIES). The AESO provides fair and open access to the grid for generation and distribution companies and large industrial consumers of electricity, and contracts with transmission facility owners to acquire transmission services and provide customer access. The AESO is independent of any industry affiliations and owns no transmission assets.

In 2007, legislation (Alberta Utilities Commission Act) was introduced to split the previous energy sector regulator, Alberta Energy and Utilities Board (AEUB), into two entities: the Energy Resources Conservation Board and the Alberta Utilities Commission. The latter is responsible for the regulation of distribution and sale of electricity and natural gas to Albertan consumers. The commission is also responsible for applications regarding new or upgraded electricity transmission lines. The Energy Resources Conservation Board focuses exclusively on the responsible development of Alberta's oil and gas resources.

More than 200 power pool participants compete to sell or buy power or provide ancillary services to the power pool. Whereas the retail market for residential, farm, and small and medium commercial consumers is also open to competition, these consumers have the option to remain on a regulated rate tariff. This default rate is known as regulated rate option, or RRO, is regulated by the AUC for each of the three RRO providers. A monthly RRO price for power is approved by the AUC, and this price is based on market prices for power.

Ontario

Ontario's electricity generation mix is the most diverse in the country, with 50% of generation from nuclear, 22% from hydro, 16% from coal, 6% from gas and the rest from alternative energy sources. The percentage of renewable energy in the supply mix is expected to increase; the Ontario government has made it a priority to bring on-line cleaner, more affordable and sustainable sources of electricity supply. In early 1999, Ontario began to promote the rationalisation of the publicly owned distribution sector, resulting in merger activity that has reduced the number of municipally owned local distribution companies (LDCs) in the province from 305 in 1999 to just over 80 at present. The government provides a transfer tax exemption to any publicly owned utility that sells its electricity assets to another publicly owned utility in Ontario to help facilitate further consolidation activity. This exemption was made permanent in October 2009.

The Electricity Act, 1998 and the Ontario Energy Board Act, 1998, are the principal legislative tools governing the electricity market in the province. The Electricity Act, 1998, provided for the establishment of five entities;

- Ontario Power Generation Inc., which provides generation;
- Hydro One Inc., which provides transmission and distribution services;
- The independent Electricity System Operator (ISEO), which administers the transmission network and electricity market;
- The Ontario Electricity Financial Corporation (OEFC), which administers non-utility generation contracts; and
- The Electrical Safety Authority (ESA), which is responsible for public electrical safety.

Ontario has combined elements of regulation and competition into a unique hybrid market. Wholesale prices created through the market are tempered by contract guarantees and fixed prices provided to a majority of generators in the province. The price customers pay is determined by the hourly Ontario rnergy price set in the market which is subsequently adjusted to take into account the various types of contract prices paid to certain generators. Generators offer into the market and are paid the market price. Those with contracts receive fixed prices, monthly revenue guarantees, or guaranteed floor prices.

Approximately 70% of the electricity in the province is produced by one company: the provincially owned Ontario Power Generation Inc. (OPG). The output from OPG's baseload nuclear and hydroelectric production receives regulated payments set by the Ontario Energy Board. OPG also owns two other nuclear generating stations which are leased on a long-term basis to Bruce Power. The Bruce nuclear stations, which are leased by OPG to private partners, produce about 20% of the balance of electricity supply while numerous smaller co-generation plants, natural gas facilities and additional renewable (wind and hydroelectric) energy facilities comprise the remaining approximate 10% of the electricity produced in Ontario.

Hydro One Networks, an operating subsidiary of Hydro One Inc., which is wholly owned by the province of Ontario, owns and operates most of Ontario's electricity transmission system, accounting for about 96% of Ontario's transmission capacity as measured by revenues. Hydro One's distribution system is the largest in Ontario and spans approximately 75% of the province. There are currently over 80 licensed electricity distributors in Ontario. Hydro One serves about 25% of the province's customer base. The second-largest distributor, Toronto Hydro, serves about 15% of the province's customers while five large distributors in and around the greater Toronto area serve approximately 20%. The remaining customer base is allocated among local municipal, First Nations, and privately owned distributors.

The Independent Electricity System Operator (IESO) was established in 1998, by means of the Electricity Act, 1998. The ISEO directs the operation and maintains the reliability of the IESO-controlled grid, and operates the wholesale electricity market, overseeing the implementation of the rules that govern the market. The IESO operates a real-time energy market in which electricity demand and supply are balanced and instructions are issued to dispatchable generators and loads every five minutes. For each five-minute interval, the IESO collects the best offers from generators and loads to provide the required amount of electricity, and publishes the market clearing price.

The Ontario Energy Board (OEB) regulates the province's natural gas and electricity industries. The OEB determines electricity transmission and distribution tariffs, and approves the Independent Electricity System Operator's (IESO) budget and fees. The Board also provides advice on energy matters referred to it by the Minister of Energy and Infrastructure, and the Minister of Natural Resources. The Board is a self-funding Crown corporation without share capital. The Board's mandate and authority come from the Ontario Energy Board Act, 1998, the Electricity Act, 1998, and a number of other provincial statutes.

The Ontario Power Authority (OPA) was established by the Electricity Restructuring Act, 2004 with a mandate to ensure a reliable, sustainable, long-term supply of electricity for the province. The OPA is required to forecast electricity demand and the adequacy and reliability of electricity resources for Ontario for the medium and long term. It is also required to conduct independent planning for electricity generation, demand management, conservation and transmission, and to develop integrated power system plans for Ontario.

British Columbia

Hydroelectricity is British Columbia's largest source of electric power generation, with almost 87% of provincial output. BC Hydro, a Crown corporation owned by the province, owns and operates the majority of the province's electricity generation assets. It also supplies electricity to the majority of residential and commercial customers. Fortis BC and Columbia Power Corporation also own hydropower generation assets. A small number of natural gas-fuelled electricity generation facilities also exist in the province.

The province has primary jurisdiction over the generation, transmission and distribution of electric power within British Columbia's borders. The Electricity and Alternative Energy Division of the Ministry of Energy, Mines and Petroleum Resources (MEMPR) assesses and makes recommendations on electricity-related policies, legislation and programmes. The Division is responsible for implementation and oversight of provincial electricity policy and manages the policy and statutory frameworks related to British Columbia's major energy Crown corporations: BC Hydro, British Columbia Transmission Corporation, and Columbia Power Corporation. The ministry also advises on matters related to the 1964 Columbia River Treaty, an international agreement between Canada and the United States for the co-operative development and operation of water resources in the Columbia River basin.

The BC Utilities Commission (BCUC) is an independent regulatory agency operating under the Utilities Commission Act. The BCUC's primary responsibility is the regulation of British Columbia's natural gas and electricity utilities.

BC Transmission Corporation (BCTC) is the provincial Crown Corporation that is responsible for managing the province's publicly owned electrical transmission system. BCTC was created in 2003 to ensure fair and open access to the transmission system. It is responsible for planning, building, maintaining and operating the electricity transmission system. The Minister for the Crown holds 100% of the shares of the BCTC, as required by the Transmission Corporation Act of 29 May 2003.

Wholesale access and free choice of electricity supplier are available to large industrial users, while smaller consumers are restricted to BC Hydro or their local distributor.

Québec

Québec is the fourth-largest hydroelectric producer in the world and the largest electricity consumer, by volume, in Canada. Although hydroelectricity is the primary source of electricity available in Québec (over 97% of 47 105 MW) it is worth noting that Québec also has nuclear capacity which currently accounts for approximately 3% of electricity generation in the province. By 2015, Québec expects to benefit from approximately 4 000 MW of wind power.

The electric industry in Québec is dominated by Hydro-Québec, a Crown corporation established under the Hydro-Québec Act and functionally divided into four separate divisions: HQProduction, HQTransÉnergie, HQDistribution and HQÉquipement. Generation is unregulated; however, Hydro-Québec Production has sole responsibility for developing hydro facilities larger than

50 MW. By law, HQProduction is required to supply HQDistribution with a maximum of 165 TWh per year (the heritage pool) for customers in Québec at a set price of CAD 27.9 per MWh. Competition exists in the wholesale market for all HQDistribution needs in excess of the heritage pool; to date no municipal distributors have exercised the option, given the low cost of power offered by HQProduction. Transmission and distribution are regulated by the Régie de l'énergie, the sector regulator. With more than 33 000 km of power lines, the transmission system in Québec is one of the largest in North America and is operated by TransÉnergie. The province has an open-access transmission tariff. Québec's electricity grid maintains high standards in terms of reliability and security, and is asynchronous to all of the other North-American grids.

Saskatchewan

Fossil fuel generation (57% from coal and 20% from natural gas) provides the majority of the electricity produced in the province, with the remainder coming from hydroelectric and wind facilities. The Saskatchewan Power Corporation (SaskPower) operates almost all power generating facilities in Saskatchewan and holds power purchase agreements with all grid-connected independent power producers. The company is also responsible for the transmission and distribution of electricity in the province, save for two municipally owned distribution franchises in the Saskatoon and Swift Current areas. SaskPower is governed by the Power Corporation Act and is subject to the provisions of the Crown Corporations Act, 1993.

Manitoba

Manitoba Hydro is a provincial Crown corporation that supplies both electricity and natural gas to its customers in the province. Manitoba's wholesale electricity market is dominated by Manitoba Hydro's largely hydroelectric generation facilities with the exception of one 99-MW independent commercial wind farm. Manitoba Hydro is provincially regulated under the Manitoba Hydro Act, The Public Utilities Board Act and the Crown Corporation Public Review and Accountability Act. Under legislation, Manitoba Hydro is the only entity that can retail power in Manitoba; retail electricity rates are regulated by the Manitoba Public Utilities Board.

Manitoba Hydro is a significant exporter of electric power to wholesale markets in Canada and the United States. It is the only one of the Canadian utilities that is a member of an international transmission organisation – the Midwest Independent System Operator (MISO).

New Brunswick

New Brunswick is the largest provincial electricity market in Atlantic Canada, accounting for about 40% of the region's electricity demand. This high per-capita demand is due, in large part, to heavy consumption by the forestry industry, as well as the use of electricity to heat 56% of the province's homes. New Brunswick has a diverse generation portfolio, which includes nuclear, fossil-fuelled, hydro and wind power generation. Almost all the residential and industrial power consumers in the province are serviced by NB Power, a Crown corporation that functions as a regulated monopoly. The Electricity Act divided NB Power into a holding company and four subsidiaries. NB Power Generation Corporation (Genco) generates most of the province's electricity at 15 hydro, coal, oil and diesel powered stations. NB Power Nuclear Corporation (Nuclearco) is responsible for operating the Point Lepreau Generating Station. NB Power Transmission Corporation (Transco) owns and operates the transmission system. NB Power Distribution and Customer Service Corporation (Disco) provides distribution services to most of the province's communities.

The Electricity Act also established the New Brunswick System Operator (NBSO). NBSO's primary responsibilities are to ensure the reliability of the electrical system and to facilitate the development and operation of a competitive electricity market in the province. The New Brunswick Energy and Utilities Board regulate the rates set by Disco and the open access transmission tariff set by the NBSO.

On 29 October 2009, New Brunswick signed a Memorandum of Understanding with the province of Québec for the sale of most of NB Power to Hydro-Québec. The deal is expected to be finalised by 31 March 2010.

Nova Scotia

Nova Scotia is endowed with large coal deposits and nearby offshore oil and natural gas fields. Most of the province's electricity (85.8%) is produced using coal or petroleum coke, the bulk of which is imported, despite Nova Scotia's large coal deposits. Nova Scotia Power Inc. (NSP) is a fully integrated regulated electric utility that provides approximately 97% of electricity generation, 99% of transmission and distribution to 95% of electricity customers in Nova Scotia. NSP was privatised in 1992, and is now a subsidiary of privately owned Emera. The remaining share of the system is owned and operated by six municipal utilities: Canso, Antigonish, Berwick, Riverport, Mahone Bay, and Lunenburg.

The Nova Scotia Electricity Act came into effect in February 2007, enabling wholesale market access with the implementation of the Nova Scotia Market Rules. The Nova Scotia Power System Operator (NSPSO), a division of NSP, is responsible for the reliable operation of the integrated power system in Nova Scotia, as well as for the administration of the NS Market Rules and the Nova Scotia open access transmission tariffs (OATT) in effect since November 2005. NSP is regulated by the NS Utility and Review Board (UARB).

Prince Edward Island

As an island province and Canada's smallest province, Prince Edward Island (PEI) is the only Canadian province without significant hydro, nuclear or petroleum sources of energy. Most of PEI's electricity is imported from New Brunswick, via two submarine cables. Around 90% of PEI's electricity customers are serviced by the fully integrated, regulated, privately owned Maritime Electric (Maritime). Maritime is a wholly owned subsidiary of Fortis, and provides transmission, distribution and a small amount of generation services. The remainder of electricity customers are serviced by the municipally owned utility Summerside Electric. Both Maritime and Summerside Electric are regulated by the all-purpose Island Regulatory and Appeals Commission. The Crown-owned PEI Energy Corporation has a mandate to pursue and promote the development of energy systems. It owns and operates 10.6 MW of wind turbine capacity (the electricity from which is sold to Maritime Electric).

Newfoundland and Labrador

The province of Newfoundland and Labrador relies heavily on hydroelectricity, generating 95% of its electricity through hydroelectric power. The majority of this hydroelectricity is exported to Québec, as the province has significant generating capacity and a small population. Newfoundland and Labrador Hydro (NLH), a Crown corporation, dominates the generation and transmission services in the province. It also provides distribution services in rural areas of the island and throughout Labrador, and to some of the province's large heavy industrial customers. NLH sells electricity wholesale to Newfoundland Power (NP), a regulated private subsidiary of Fortis, for distribution to customers in urban areas. NP serves 85% of all residential and commercial distribution customers, and also owns some generation (147 MW) and transmission facilities. In addition to NLH and NP, there is some generating capacity owned by industry and independent power producers totalling 278 MW. Both NLH and NP are regulated by the Board of Commissioners of Public Utilities, NLH on a rate-of-return basis and NP on a cost-of-service/return-on-rate basis.

In January 2008, the Newfoundland and Labrador Energy Corporation was initiated with the mandate of developing the province's energy resources, focusing on oil and gas, wind energy, research and development, the proposed Lower Churchill hydro project, and the Upper Churchill project. The Energy Corporation is wholly owned by the province and is the parent company of Newfoundland and Labrador Hydro (NLH), Churchill Falls Labrador Corporation (CF(L)Co), other subsidiaries currently owned by NLH and new entities created to manage the province's investments in the energy sector. This new structure permits both regulated and non-regulated activities to exist and grow within separate legal entities.

Box 3

The Lower Churchill River Project

The Churchill River in Labrador is a significant source of hydropower with much remaining potential. In 2007, guided by a long-term Energy Plan to manage these energy resources, the government of Newfoundland and Labrador created a new provincial Crown corporation - Nalcor Energy – to exploit this potential. The existing 5 428 MW Churchill Falls generating station, which began producing power in 1971, harnesses about 65% of the potential generating capacity of the river. The remaining 35% is located at two sites on the lower Churchill River, known as the Lower Churchill River Project.

The proposed Lower Churchill River Project development consists of the construction and operation of two large hydroelectric power generating facilities at undeveloped hydroelectric sites, one at Gull Island (2 250 MW) and the other at Muskrat Falls (824 MW), interconnecting transmission lines and the construction of associated dams and reservoirs. Gull Island and Muskrat Falls are located approximately 100 km and 30 km to the south-west of the town of Happy Valley-Goose Bay.

The province is considering a number of transmission routes for eventual export to other jurisdictions, including through the province of Québec or via an undersea cable to the maritime provinces.

The CAD 7 billion project is expected to take ten years to complete. The commencement date for this project is currently under consideration. Construction at Muskrat Falls will start approximately three years after the start of the Gull Island construction.

Nalcor Energy has been given the mandate by the province to develop the Lower Churchill Hydroelectric Generation Project for the benefit of residents of Newfoundland and Labrador. The project aims to:

- meet the future demand for hydroelectric generation in the province;
- provide an electric energy supply for sale to third parties; and
- develop the province's natural resource assets for the benefit of the province and its people.

The project will contribute to GHG emissions reductions in the province, but also nationally and in the United States. Output from Lower Churchill River has the potential to eliminate the need for the thermal generating capacity elsewhere in the province and displace existing fossil-fuel generation elsewhere. The developers anticipate that 800 MW will be required to meet provincial needs and the remaining capacity will be available to meet new capacity demand within the province and for export to other markets in the north-east of North America.

Yukon

The Yukon generates most of its electricity from hydro, with the remainder coming from diesel-fired generation units and a small amount of wind power. The very low population density of the Yukon means that many isolated communities and industrial sites rely on diesel-fired generation plants and local distribution networks. The Yukon Energy Corporation (Yukon Energy), a subsidiary of the Crown-owned Yukon Development Corporation, is the dominant power generator with almost 90% of capacity, including all the major hydro facilities. It also owns and operates two separate transmission systems (in the process of being connected – to be completed in 2011) that serve loads in the vicinity of Whitehorse-Aishihik-Faro and Dawson City-Mayo. The Yukon Electric Company Limited (YECL), a subsidiary of ATCO Electric, owns and operates the remaining generating capacity in most of the Yukon's other rural communities. Outside the Dawson City area, YECL handles most of the distribution in the Yukon and in some places, including the capital city Whitehorse, distributes power as a wholesale customer of Yukon Energy.

Northwest Territories

The Northwest Territories (NWT) obtain electricity from hydro, diesel and a small amount from natural gas. The majority of electricity is from hydro, while some communities rely on diesel-fired units or locally available natural gas fuels for power generation. The Northwest Territories Power Corporation (NTPC), a Crown corporation of the government of the Northwest Territories, is the main producer of electric power. Distribution is handled by Northland Utilities (a subsidiary of ATCO Electric) in Hay River, Yellowknife, and four other isolated communities. NTPC looks after distribution in the remainder of the NWT. The Northwest Territories Energy Corporation (2003) is a subsidiary of NTPC and works specifically on the several potential NWT hydroelectricity developments. In 2007, the two major developments on which the Energy Corporation is working are the expansion of the Taltson hydro generation facility and the development of hydro generation on the Great Bear River.

Nunavut

In 2001, two years after the 1999 creation of Canada's Nunavut Territory, the Nunavut Power Corporation was established through the Nunavut Power Utilities Act (NPUA) to take over the assets of the Northwest Territories Power Corporation within Nunavut. The NPUA was renamed the Qulliq Energy Corporation Act in 2003 and Nunavut Power Corporation was established as a subsidiary of Qulliq Energy Corporation (QEC), a Crown corporation responsible for the generation and distribution of electricity within the territory. The Nunavut electrical system consists of isolated diesel generators with no interconnections with neighbouring provinces. All aspects of QEC are regulated by the Ministry of Energy; however a Utility Rates Review Council has been established to provide independent advisory services in review of utility applications, major capital projects, and electricity rates.

TRANSMISSION AND DISTRIBUTION

TRANSMISSION NETWORK

The existing Canadian transmission network extends over 160 000 km. It is characterised by north-south backbones, in part owing to the location of most major load centres near the Canada-United States border and major hydro projects in the northern regions of British Columbia, Manitoba, Ontario and Québec. In all regions of the country, transmission upgrades are required to accommodate greater load, more generation points, enhanced interprovincial and international trade, and reliability. Transmission planning is a provincial responsibility.

Network Access

The management of energy resources, including electricity transmission networks, falls under provincial jurisdiction. Canadian utilities must provide reciprocal non-discriminatory open transmission access to sell electricity directly to customers in the United States at market-based prices. As such, many Canadian transmission providers have filed Open Access Transmission Tariffs (OATT) with the United States Federal Energy Regulatory Commission (FERC) in response to Order 888. Three provinces have transmission service providers that have not filed open access tariffs with FERC: Newfoundland and Labrador, Ontario and Alberta. These provinces have developed provisions and tariffs which are compatible with the OATT reciprocity and non-discrimination criteria. The major regulated transmission owner in Ontario, Hydro One, filed its own tariff for approval with the Ontario Energy Board. FERC has ruled that the Ontario system provides transmission access equivalent to that in an OATT. Alberta opened a fully competitive wholesale market, while Newfoundland and Labrador does not sell directly to the United States at this time.

In jurisdictions with OATT and without a competitive wholesale market, potential transmission system users can reserve transmission capacity. When a new facility becomes available or when the OATT is first implemented, the transmission owner holds an open season, where all requests are treated as being received at the same time. After the initial allocation, all requests are treated on a first come, first serve basis. In allocating transmission capacity, requests for firm service have priority over requests for non-firm service, and requests for long-term rights have priority over requests for short-term rights.

Transmission providers maintain an internet-based system called Open Access Same-Time Information System (OASIS) through which all transmission

Figure 38

International and Interprovincial Transfers of Electricity, 2008 (GWh)*

The boundaries and names shown and the designations used on maps included in this publication do not imply official endorsement or acceptance by the IEA.

* arrows indicate import/export transactions and may not represent the actual electricity flow route from source to destination.

Source: NEB, Statistics Canada.

customers can schedule transmission that is unreserved or not being used by the market participant that holds the reservation.

New Network Connections

Transmission planning is under provincial jurisdiction, and as a result the procedure for connecting new capacity to the grid varies from province to province. Although independent power generators have access to the wholesale markets in Ontario, Québec, Manitoba, Saskatchewan and Nova Scotia, administration of interconnections to provincial grids and open access tariffs has been left to the province's incumbent utility.

In contrast, although two Crown corporations, BC Hydro and New Brunswick Power, remain the owners of most of the power lines in their respective jurisdictions, the management of transmission systems has been placed in the hands of independent organisations: the British Columbia Transmission Corporation and the New Brunswick System Operator. Alberta and Ontario have slightly different arrangements in place. In both provinces, the interconnection process is overseen by the independent system operator; however, the owners of the transmission or distribution facilities as well as the provincial regulatory board may also have a role in approving or assessing proposed connections to the grid.

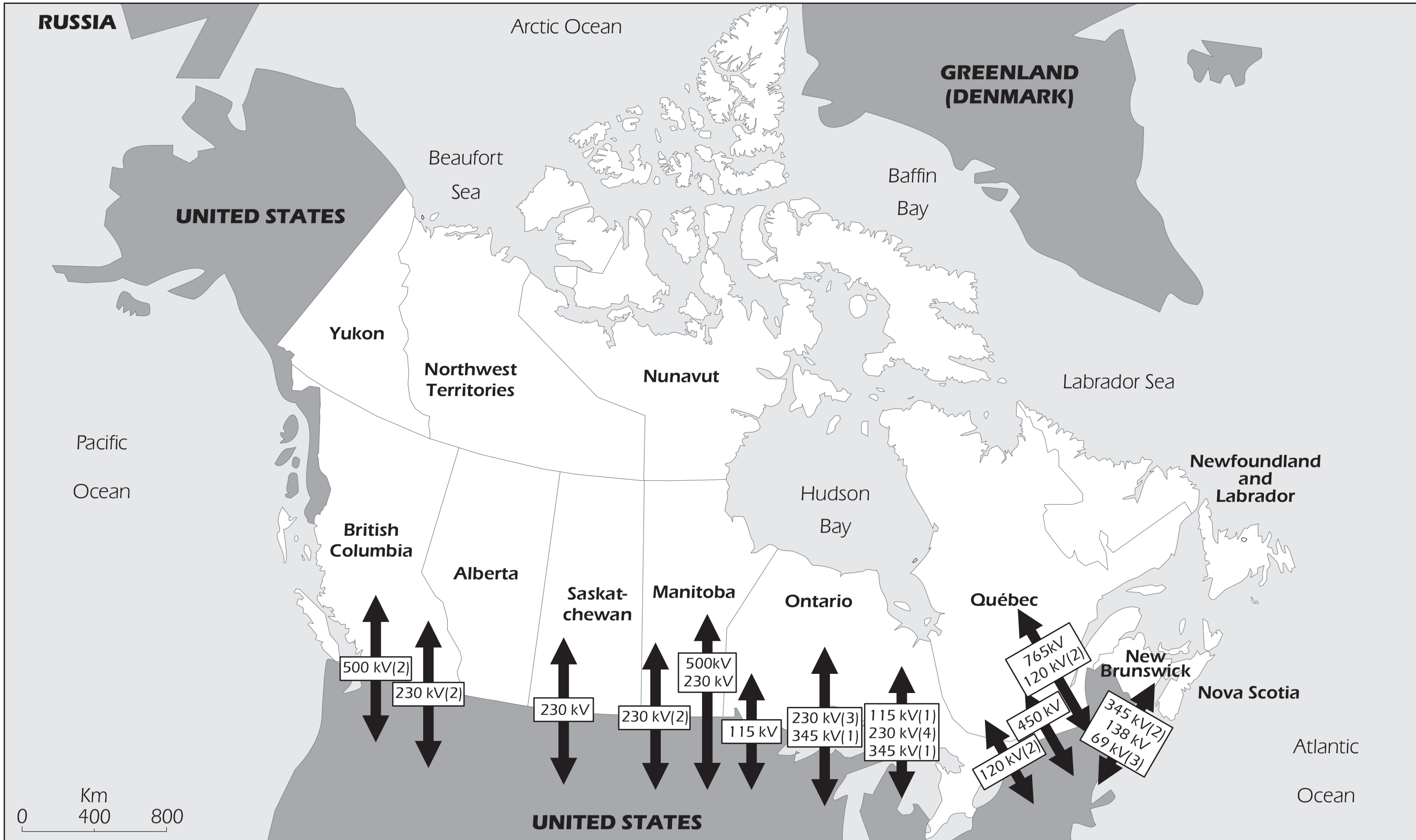
Technical interconnection standards are determined by the North American Electric Reliability Council (NERC) and are a requirement for entities wishing to connect new generation to the Canadian transmission grid. While utilities are subject to NERC rules and reliability standards, these rules must be approved or adopted by the provincial regulators, who may impose stricter standards (often owing to more severe climatic conditions in parts of Canada). The process to connect a generator is generally the same across the country. First, the utility, transmission system owner or independent system operator undertakes a number of studies at the proponent's expense. This includes an interconnection impact study to evaluate the impact of the proposed interconnection on the reliability of the transmission system and a facilities study to provide a cost estimate of the equipment, engineering, procurement and construction work needed to connect the customer to the grid. A feasibility study to assess the viability of the project may also be required. Afterwards, the proponent signs an agreement with the grid administrator that governs the obligations and requirements of both the administrator and the interconnection customer.

TRADE AND TRANSIT

Canada is a net exporter of electricity to the United States mainly because of the availability of lower-cost hydroelectric resources. Electricity exports are expected to continue to be a significant source of revenue, and imports

Figure 39

Major Transmission Interconnections between Canada and the United States



The boundaries and names shown and the designations used on maps included in this publication do not imply official endorsement or acceptance by the IEA.

Source: NRCan.

are expected to provide reliability for those provinces interconnected with adjacent United States regions. In addition to exporting power, hydro-rich provinces can also benefit from their ability to purchase less expensive thermal power at off-peak (night-time), and save hydro resources that can be used to generate electricity for export when peak (day-time) prices are higher.

Total exports and imports in 2007 equalled 57.7 GWh and 25.2 GWh. The provinces of Québec, Manitoba and Ontario exported the greatest volumes of electricity.

Cross-Border Transmission Lines

There are international transmission lines connecting New Brunswick, Québec, Ontario, Manitoba, Saskatchewan and British Columbia to the United States. Further connections are under construction or being planned:

Montana Alberta Tie Limited (MATL) has received approval to construct and operate a 230 kV interconnection between Lethbridge, Alberta and Great Falls, Montana. This will be the first major interconnection between Alberta and the United States.

Seabreeze proposes to build the Juan de Fuca Cable Project – a 550 MW connection between Vancouver Island and Port Angeles, Washington using high-voltage direct-current (HVDC) light technology. If built, the line would be the first underwater merchant line between Canada and the United States. The project is currently undergoing the regulatory process in Canada, and has received approval in the United States.

The proposed Canada/Pacific Northwest to Northern California Transmission Project will transport up to 3 000 MW of power from new renewable resources in British Columbia, to the Pacific north-west and northern California, over a 1 600 km-long transmission line. The project aims to be operational by 2015.

Distributed Generation and Wind Power Integration

There is little distributed generation in Canada at present, although some jurisdictions are promoting these technologies as an important resource for the future. Natural Resources Canada, by means of CanmetENERGY (the clean energy R&D technology development agency), has been championing the development of product standards and certification requirements in order to demonstrate that distributed energy resources can be safely interconnected. In 2006, NRCan published the second edition of *Micropower Connect: A Status and Review of Micropower Interconnection Issues and Related Codes, Standards and Guidelines in Canada*. In addition, amendments to the Canadian Electricity Code have been made to accommodate new technology.

CHP DEVELOPMENT

Combined heat and power (CHP) is primarily used in the forest products sector, the oil-sands sector and other manufacturing industries. Beyond manufacturing, only a small number of district energy systems have been developed to date. In Ontario, the Ontario Power Authority (OPA) has posted a Request for Expressions of Interest (RFEI), which is intended as a first step towards a potential future CHP procurement for larger gas-fired and waste-heat co-generation projects. The new process follows a successful CHP procurement programme completed in 2006 – the first of its kind in Canada.

In October 2006, the OPA awarded seven contracts for a total capacity of 414 MW. These projects represented a total capital investment of some CAD 800 million and ranged in size from a 2-MW district energy project in Oshawa to a 236-MW industrial application in Thorold. The OPA also initiated a procurement process for up to 100 MW of renewables-fuelled CHP, and will be introducing a programme, the Clean Energy Standard Offer Program (CESOP), for small-scale gas-fired and waste-heat CHP projects of 10 MW or less, connected at distribution level.

CHP developers will also be able to avail of British Columbia's Innovative Clean Energy Fund. Announced in 2007, this initiative will provide CAD 25 million to support pre-commercial energy technology that is new, or commercial technologies not currently used in the province. A two-phase call for power to utilise wood infected by the mountain-pine beetle as well as other wood-fibre fuel sources was also made around the same time. In addition, the utility also had a "customer-based generation" call for power in 2002.

In Alberta's open competitive market, independent firms have developed over 4 000 MW of CHP generation in the forestry, oil-sands, petrochemical and other sectors.

DISTRIBUTION AND RETAIL

In most Canadian provinces, the distribution system is largely comprised of publicly owned monopolies. This is the case in British Columbia, Saskatchewan, Manitoba, Québec and New Brunswick. In these jurisdictions, distribution infrastructure not owned by the province is generally controlled by municipal utilities, although distribution services in the south-central portion of British Columbia are provided by Fortis, a privately owned utility. In Nova Scotia, the main regulated utility is privately owned. In Newfoundland, 85% of all residential and commercial distribution customers are serviced by Newfoundland Power, a subsidiary of Fortis. In Ontario, Hydro One is the largest electric distribution company in the province, followed by Toronto Hydro, which serves about 15% of Ontario's customers. Alberta's distribution network is a mix of investor- and municipality-owned utilities.

Only Alberta and Ontario have established competitive retail markets within their boundaries. Since 2001, all electricity consumers in Alberta may choose to receive their electricity from a regulated rate option (RRO) provider, or they may choose to obtain their energy from a competitive retailer, with whom they sign a contract agreeing to a rate plan for their electricity. Competitive retailers are licensed by Service Alberta, which also reviews the companies' retail contracts before granting them a licence to offer competitive electricity (and/or natural gas service). Consumers in Ontario can choose to stay with their local distribution company or to sign a supply contract with a retailer licensed by the Ontario Energy Board (OEB). In addition, large consumers of electricity with an interval meter can choose to purchase electricity at the spot market price.

ELECTRICITY SECURITY

SUPPLY

With transmission systems that are interconnected at multiple points from east to west, Canada and the United States are able to benefit from a significant electricity trading relationship. This relationship allows for efficient use of resources (especially between summer and winter peaking regions), commercial opportunities for both countries and improved reliability of the electric system. Following the August 2003 blackout, which affected consumers in Ontario and the north-east United States, provinces have adopted, or are working towards adopting, mandatory reliability standards. The governments of Canada and the United States are continuing to work together on common electricity reliability issues.

The North American Electric Reliability Council (NERC) forecasts that overall peak demand for electricity in Canada (which occurs in winter, except in the province of Ontario) will increase by over 6 000 MW or 6.4% in the next ten years. Conversely, committed resources are projected to increase by 11 000 MW or over 10%.

While these figures indicate some improvement in capacity margins, certain areas will still need additional supply-side or demand-side resources in the near term to ensure adequate margins. However, there are a number of issues that may affect the long-term reliability and effectiveness of the system:

- figures indicate some improvement in capacity margins, but certain areas will need additional supply-side or demand-side resources to ensure adequate long-term margins;
- integration of wind, solar and nuclear resources must be properly managed;
- increased reliance on natural gas in some regions;
- an ageing workforce and lack of skilled workers.

One of the most significant issues driving energy security concerns in the Canadian electricity market is the need for new investment in both generation and transmission. While the situation varies from province to province, certain markets may face shortfalls in generating capacity in the next 10 to 15 years owing to replacement, refurbishments and new-build requirements to meet increasing demand. Total transmission miles are projected to increase by 4.8% over the next ten years; however, efforts to expand and reinforce the transmission network continue to lag behind the growth in electricity demand and generating capacity in some areas of the country.

There are transmission developments across the country to improve reliability, access to new generation and adjacent markets, and to address increased demand and ageing infrastructure concerns. A significant interprovincial development is the 1 250 MW high-voltage direct-current (HVDC) transmission line from Québec to Ontario, promoted jointly by Hydro-Québec TransÉnergie and Hydro One Networks, which went into service in November 2009. In addition, many announcements have been made across the country as provinces develop transmission plans in anticipation of growth and trade, and reinforcements of existing facilities.

DEMAND

Electricity pricing is the exclusive domain of the provincial governments; therefore, efforts to enhance customer response in the electricity market vary from province to province. In Ontario, large commercial, industrial and institutional entities that consume more than 250 000 kWh per year, approximately 50% of Ontario load, pay the hourly spot price in the Independent Electricity System Operator (IESO) market. Households and small businesses using less than 250 000 kWh per year are billed on a fixed rate, referred to as the regulated price plan. In 2005, the government of Ontario introduced the Smart Metering Initiative programme to equip every household and small business in the province with a smart meter by the end of 2010. A phased approach is being applied to time-of-use (TOU) pricing for those customers, with approximately 250 000 residential and small business customers in Ontario now being billed on TOU rates (as of December 2009).

British Columbia (BC) has been conducting its Conservation Research Initiative since November 2006 to test time-of-use rates and smart meters. BC Hydro has introduced an inclining block rate for residential customers to encourage energy efficiency. Industrial customers have both stepped rates and time-of-use rates. Furthermore, in 2008, British Columbia announced plans – the Smart Metering & Infrastructure (SMI) Programme – to install smart meters across the province. The programme will be complete by the end of 2012 according to relevant legislation announced early in 2008. BC also has very active demand-side management programmes, including Power Smart and

LiveSmart BC. Pilot projects with time-of-use pricing are also under way in Manitoba and Alberta. Manitoba also has a curtailable rates programme and has recently adopted an inverted rate (block energy rates that increase with consumption) for industrial/commercial customers.

REGULATION AND MARKET REFORM

REGULATORY INSTITUTIONS

The regulation of electricity falls almost entirely under the responsibility of the provinces. As provinces have moved towards various degrees of competition, or have privatised parts of the industry, the role of independent regulators has increased. The following are the regulatory bodies with responsibility in each province:

- British Columbia: Public Utilities Commission;
- Alberta: Alberta Utilities Commission(AUC);
- Saskatchewan: Province of Saskatchewan;
- Manitoba: Province of Manitoba and Public Utilities Board;
- Ontario: Ontario Energy Board;
- Québec: Régie de l'énergie;
- New Brunswick: Provincial government;
- Nova Scotia: Utility Review Board;
- Prince Edward Island: Regulatory and Appeals Commission of PEI;
- Newfoundland and Labrador: Commissioners of Public Utilities;
- Yukon: Yukon Utilities Board;
- Northwest Territories: Public Utilities Board;
- Nunavut: Government of Nunavut.

The federal government, through the National Energy Board (NEB) has limited responsibilities for electricity. Specifically, the NEB regulates power exports and the construction and operation of international lines and has latent powers to designate interprovincial power lines as subject to its regulations. In Ontario and Alberta, grid management is the responsibility of, respectively, the Ontario Independent Market Operator and the Alberta Electric System Operator (AESO). No other provinces have independent transmission system operators at present.

The NEB is responsible for regulating the international electricity lines that transport power from Canada to the United States and certain interprovincial power lines deemed to fall under federal jurisdiction. The NEB responsibilities include the export of electricity and the construction and operation of international and designated interprovincial power lines. Approximately 90% of the NEB's costs are recovered from payments made by the parties it regulates, mainly through natural gas pipeline tolls and payments made by electricity exporters. The NEB is a court of record and has certain powers of a superior court of record, including those for attendance, swearing and examination of witnesses, the production and inspection of documents, the enforcement of its orders and the inspection of property.

In general, NEB decisions or orders are final and conclusive, although appeals on points of law or jurisdiction may be made to the Canadian Federal Court of Appeals. NEB members are appointed by the Governor–in-Council for a period of seven years, but may be removed at any time on address of the Senate and House of Commons.

The vast majority of generation, transmission and distribution services in Canada are overseen by provincial regulatory agencies, which have a number of features in common. Generally, these boards and commissions are independent, quasi-judicial adjudicative tribunals that take decisions independent of government direction in accordance with enabling legislation, regulation and stated public policy. They report to provincial legislative assemblies through their responsible minister, and sometimes regulate gas utilities and other industries. Provincial Cabinets have the power to appoint, and in most cases remove, Board members or commissionaires, who are empowered to set their own procedures, hire staff and consult with outside experts. Challenges to the agencies' orders or decisions are made through the provincial Court of Appeal.

There are two exceptions to this general description, Saskatchewan and Nunavut, that have established advisory bodies to conduct reviews and provide opinions on the fairness and reasonableness of rate changes proposed by the public utilities. However, decisions regarding rates are approved by the Governor-in-Council, and as a consequence, electricity rates in these jurisdictions are effectively set by the ministerial cabinet. In Saskatchewan, the Rate Review Panel receives specific instructions on the scope of each review through a "ministerial order" from the Minister of Crown Management Board. In Nunavut, the Minister of Energy is obliged by legislation to seek the advice of the Utility Rates Review Council, although he or she is not bound by its recommendations. The Rate Review Panel and Council, along with the NEB and the provincial boards and commissions, are members of the Canadian Association of Members of Public Utility Tribunals, a self-supporting, non-profit organisation that provides a forum for the exchange of information and views on utility regulation in Canada.

Over the last decade, new regulatory institutions have been created and existing ones have acquired new responsibilities in response to the introduction of competitive wholesale markets and, in Alberta and Ontario, competitive retail electricity markets. Regulatory agencies in British Columbia, Nova Scotia and Québec were granted oversight of the open access transmission tariffs (OATT), while in New Brunswick they also were given responsibility for licensing wholesale market participants. Ontario established the Market Surveillance Panel, which is part of the Ontario Energy Board, to monitor, investigate and report on activities and behaviour in the province's electricity markets. Similarly, Alberta created the Market Surveillance Administrator, an independent statutory agency appointed by the Minister of Energy, to ensure competitive electricity markets. The Competition Bureau, an independent Canadian law-enforcement agency, also plays a role in governing business conduct and preventing anti-competitive practices in competitive electricity markets. The Commissioner of Competition is appointed by the government of Canada and reports to Parliament through the Minister of Industry.

RETAIL MARKETS

Although Canada's electricity system is highly integrated with the United States, retail markets remain separate. Alberta and Ontario established competitive retail markets in the 1990s and early 2000s, but other provinces have yet to follow.

In Alberta, more than 200 market participants are competing to buy and sell power to the province's larger commercial and industrial users, who account for roughly two-thirds of all electricity usage in Alberta. With the continued development of the retail market, more retail options will be available to smaller consumers such as residential, farm and small commercial customers. Alberta has recently begun phasing in a new regulated rate for consumers, in order to manage the transition to a competitive retail market. This phasing-in of the new regulated rate is expected to afford consumers with appropriate protection during the transition period while at the same time stimulate retail competition. The new regulated rate will, by 2010, be entirely based on month-forward contracts in the wholesale market.

Ontario's Smart Meter Initiative is expected to be a key driver for technological innovation in home energy management. To date, Ontario's local distribution companies have installed over three million smart meters in households and small businesses and are on target to accomplish installation of a smart meter in 4.5 million households and small businesses by the end of 2010.

WHOLESALE ELECTRICITY

The most competitive wholesale market in Canada is the market in Alberta, a real-time spot market for electricity, open to all qualifying generators. Participants, including generators, marketers, importers and large customers, who register with the Alberta Electric System Operator (AESO) can buy and sell power from the pool. Since the last in-depth review in 2004, Nova Scotia has opened its wholesale electricity market following the passage of the Electricity Act. The Act allows the province's six municipally operated electrical companies to buy power from generators other than Nova Scotia Power, a privately owned and regulated monopoly. The Act also mandates the establishment of an open-access transmission tariff.

In Ontario, the Independent Electricity System Operator (IESO) is investigating the development of an enhanced day-ahead commitment (EDAC) process in the IESO-administered Ontario market. The IESO is consulting stakeholders on implementing the EDAC process, which would largely comprise an integration of new components to the current day-ahead commitment, pre-dispatch and real-time dispatch processes to improve the efficiency of the current market. Currently, none of the other provincial governments have plans for further wholesale electricity market reforms, although New Brunswick recently announced a review of the province's energy sector.

ELECTRICITY PRICES

PRICING POLICY

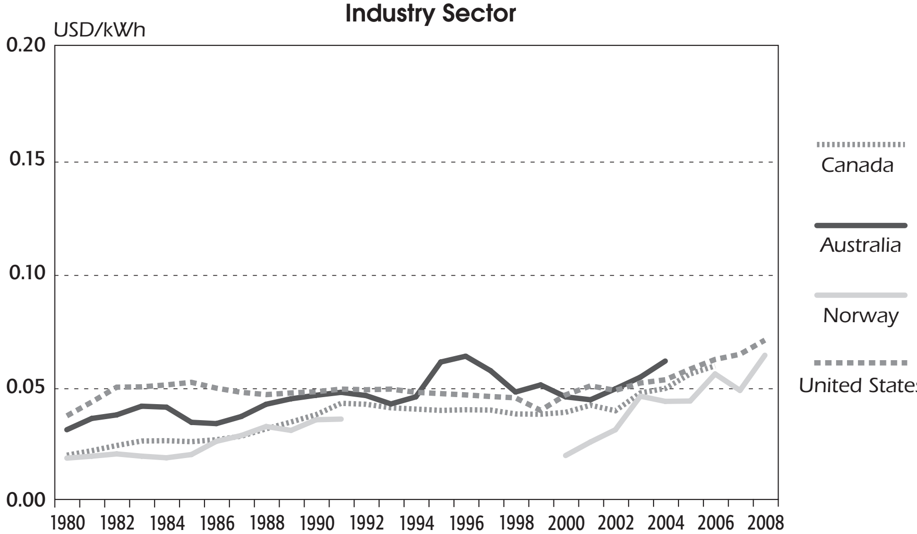
Electricity pricing varies by province or territory according to the volume and type of available generation and whether prices are market-based or regulated. With the exception of Alberta and Ontario, prices are regulated by a quasi-judicial board or commission. At the retail level, the price of electricity is not only affected by the cost of production but also by the cost of transmission and local distribution, which may vary depending on factors such as geography and population density. In Québec, Nova Scotia, Prince Edward Island and Newfoundland and Labrador, electricity rates are regulated on a cost-of-service basis. In Alberta, prices are set through the market, although households and smaller commercial consumers have the option of subscribing to a regulated rate.

Ontario householders who purchase electricity from their local utility are charged a rate set by the Ontario Energy Board as part of the regulated price plan. The threshold that defines higher and lower electricity prices for residential regulated price plan consumers is set at 600 kWh per month during the summer (1 May to 31 October) and 1 000 kWh per month during the winter (1 November to 30 April). This difference recognises that consumers use more electricity for lighting and indoor activity in the winter and that some Ontarians are reliant on electricity for their heating. Ontario customers with smart meters pay time-of-use rates based on three weekday time periods – off-peak, mid-peak and on-peak – whose times vary in summer and winter seasons. Weekends and holidays are always off-peak during both the winter and summer periods. All Ontario householders also have the option to purchase electricity from an electricity retailer, under rates stated in the retailer's contract.

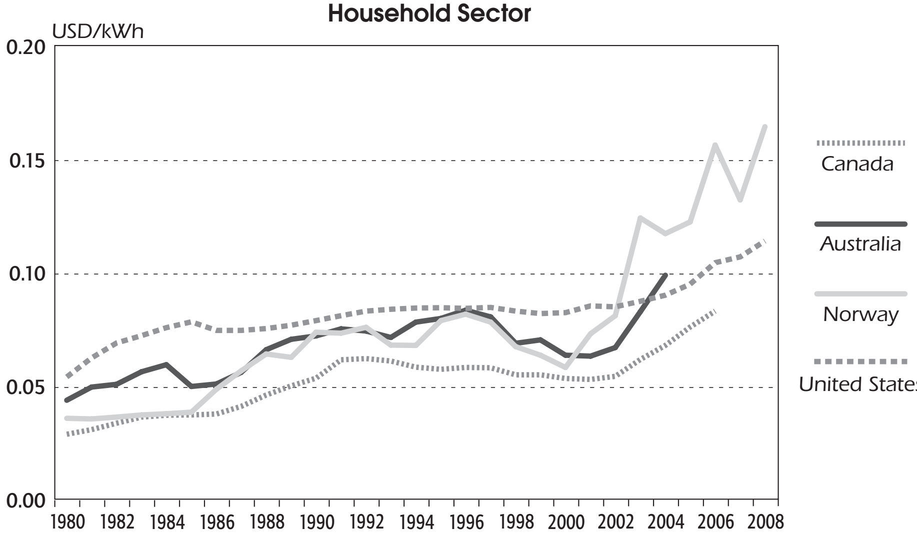
Figure 40

Electricity Prices in Canada and in Other Selected IEA Member Countries, 1980 to 2008

Industry Sector



Household Sector



Source: *Energy Prices and Taxes*, IEA/OECD Paris, 2009.

Table 16

Average Electricity Price across Canada (CADcents per kWh)*

	Residential users	*General service small users*	*General service medium users*	*General service large users*
2002	8.60	9.54	8.48	5.67
2003	9.90	10.13	9.11	6.18
2004	9.82	10.19	8.99	6.07
2005	10.25	10.59	9.50	6.55
2006	8.74	8.75	7.65	5.44
2007	11.08	11.35	9.94	6.73

* The data were taken from Hydro-Québec's annual comparison of electricity prices in major North American cities. On 1 April of each year, Hydro-Québec compiles data on average prices per kilowatt-hour for Montreal, Toronto, Ottawa, Winnipeg, Halifax, Charlottetown, St. John's, Regina, Vancouver, Edmonton and Moncton. The data are arranged into residential (<1 MWh) and three types of general consumers: small (10 MWh), medium (100 MWh) and large (300 MWh to 3 000 MWh). The Residential and General service small users columns were taken directly from the Residential and the Smaller General User series, while the medium and large users are averages of all the prices included in these categories.

NETWORK FEES

The open access transmission tariff (OATT) defines the rates, terms and conditions associated with network transmission services. The tariff and the schedules of fees are usually posted on the website of the independent system operator (ISO) or the Open Access Same-Time Information System (OASIS) site.

In Canada, one transmission provider dominates each province, so transmission tariff pancaking (the accumulation of transport charges as power moves across different systems) can only occur for transactions crossing several provincial borders. Given the large geographical area of most provinces, cross-jurisdictional transfers of electricity are not as common as in countries where there are numerous transmission-owning parties.

A strategy adopted in the United States to eliminate transmission tariff pancaking is to put all the transmission providers under the control of a single system operator in the form of an RTO (regional transmission operator). Market participants within an RTO pay only a single transmission tariff, whether they are moving power within a single utility or across several utilities in that region. For trade purposes, Manitoba Hydro participates in the Midwest Regional Independent System Operator (MISO).

CRITIQUE

The governance framework for the electricity sector in Canada is almost entirely provincially regulated with each province having its own economic, technical and safety regulator. Despite this, there is a large degree of collaboration to comply with United States open access transmission tariff rules that has led to reasonably consistent mechanisms for economic regulation of transmission through open access tariffs among Canadian and United States transmission providers. Although there are differences between provinces, this has not presented a significant problem for investment to date, and delays, should they occur, are more likely to be attributed to siting and approvals requirements and the commercial need for power transfers before transmission is built. Historically, electricity systems and utilities have developed separately within each province, with interconnection only gradually becoming more significant. As this situation changes, and more provinces consider open markets with greater demand for interprovincial and international trade, there is a case for harmonising some elements of governance. Given the size of Canada, this may work best on a regional level, perhaps modelled on the North American Electric Reliability Council (NERC) reliability regions, rather than nationally. Greater federal government involvement may facilitate this process.

An exception to the provincial governance model is the regulation of reliability of the North American bulk power system. Provincial instruments still underpin reliability requirements; however there is a degree of oversight from the NERC and delegated regional co-ordinating councils. The role of reliability organisations has been strengthened following the 2003 blackouts. In many provinces, NERC standards have been approved or adopted by the provincial regulators, which in some cases impose further standards. It may be possible to improve regulatory efficiency by providing the NEB with authority regarding reliability of Canadian cross-border and cross-provincial transmission systems. Whereas not all of the reliability task force's recommendations have been fully implemented, it appears that equivalent outcomes are being achieved in most provinces. The federal government has facilitated the establishment of the relationships required, including the international relationships with the United States government and the US Federal Energy Regulatory Commission (FERC) which provide authority to the reliability organisations in the United States.

Canada as a whole has a diverse mix of generation of fuel sources, some of which (coal and hydro) tend to be more concentrated in particular provinces. Supply-side risks (such as exposure to drought in hydro systems) are partly mitigated through interconnection, particularly with neighbouring United States systems but also between provinces. Some systems have a high proportion of coal-fired power plants; short-term implications for energy security in the transition to carbon-pricing should be assessed as part of Canada's long-term climate change strategy. Commendably, the federal government and individual provinces are devoting considerable resources to carbon capture and storage technology to help mitigate this risk in the long term.

A further challenge facing the electricity industry in Canada is the federal government's commitment to ensure that 90% of electricity needs come from non-emitting sources by 2020. This is an increase of 15% on present levels; therefore, approximately 110 TWh of carbon-emitting output must be displaced. In order to meet this significant challenge, the federal government will have to work very closely with provincial authorities in planning and authorising generation facilities.

There is a degree of utility unbundling in most provinces; however, only two have established transparently traded wholesale and competitive retail markets. In most provinces, unbundling has been driven by FERC reciprocity requirements for trade with the United States – as has the adoption of open access transmission tariffs – which generally use the FERC template. The compliance with FERC open access transmission requirements and wholesale market rules reflect Canada's willingness to work collaboratively with US regulators in the larger North American market. This should provide significant benefits to both Canada and the United States.

Several provinces have made steps to liberalise their electricity markets, although it appears that only Alberta has an effective open market at either wholesale or retail level. In general, the conditions for decentralised investment decision making do not appear to be in place in other provinces. At provincial level, Ontario has provided tax exemptions designed to encourage consolidation of distribution companies. The federal government could also remove barriers to the transfer of assets from existing monopoly entities to competing entities, for example by amending the capital gains tax rules. Markets in some provinces may be too small to establish an effective market alone, and could benefit from participation in regional markets with other neighbouring provinces. The federal government could facilitate this in more areas, as it is currently doing through the Atlantic Energy Gateway initiative.[50]

Some provinces have expressed interest in greater transmission interconnection and there are a number of projects under way to strengthen interconnection. There are also active proposals for merchant transmission lines from some provinces to neighbouring states. The federal government has set aside money for infrastructure spending, and included transmission in the potential basket of investments. We consider the federal government should avoid taking equity in transmission given that there are other entities that appear willing to make this investment. Furthermore, the fact that electricity regulation is mainly a provincial matter does not help in terms of regulatory approvals for infrastructure projects. For example, the Québec-Ontario 1 250-MW line was delayed for several years owing to multi-jurisdictional issues. Perhaps a stronger federal mandate would facilitate the implementation of needed cross-provincial transmission projects. *Turning the Corner* identifies an east-

50. The Atlantic Energy Gateway initiative, announced in March 2009, is a federal-provincial effort to facilitate the development of the Atlantic renewable energy sector by fostering collaboration, common understanding and communication between governments and the private sector. Specifically in the electricity sector, this initiative works to advance alternative power sources like wind, solar, tidal and biomass, in addition to traditional sources such as hydro and nuclear, to generate electricity.

west transmission grid among a number of specific measures to reduce emissions from the electricity sector. The federal government could also seize the initiative here and use a forum such as the Council of Energy Ministers to further develop the concept with the provinces. Furthermore, *Turning the Corner* notes that "should it not be possible to move ahead on this in co-operation with the provincial governments and electricity utilities, the federal government will consider other options, including regulations if necessary, to meet this goal."

Many provinces have experienced, or are expecting, growth in renewable electricity – especially wind energy. Ontario's Green Energy Act (GEA) contains North America's most comprehensive feed-in tariff, which is expected to spark the development of numerous renewable energy projects. The tariff offers guaranteed incentives to developers of wind, water, solar, biomass and biogas sourced power that will serve to promote green energy projects. Since October 2003, more than 1 200 MW of new renewable energy projects have come on line in Ontario and project activity is expected to ramp up with the implementation of the provisions of the GEA.

Power system operators in some jurisdictions report emerging grid integration issues. Some provincial system operators are collaborating to share ideas and experience to manage grid integration issues and forecasting. The Meteorological Service of Canada (MSC) has developed long-term wind maps that help to identify investment opportunities; and many Canadian system operators are in the process of developing their own short-term wind forecasting systems[51] to assist with the efficient dispatch of generation.

RECOMMENDATIONS

The government of Canada should:

- *Facilitate market opening and integration between provincial markets and with neighbouring United States markets to increase the transparency of generation investment signals, potential for competition in electricity wholesale and retail markets, and to simplify governance and oversight of reliability planning and system operation.*
- *With the provinces, examine whether the transmission system could be more efficiently used and developed over the long term.*

51. For example: http://www.ieso.ca/imoweb/pubs/consult/se57/se57-20090811-Centralized-Forecasting-Variable-Generation.pdf (last accessed 31 December 2009).

NUCLEAR ENERGY

OVERVIEW

Canada is a pioneer of nuclear energy, having developed its own pressurised heavy water reactor (PHWR) technology, known as the CANDU (Canadian deuterium uranium reactor). In 2008, nuclear generating capacity of 12.5 GW provided Canada with 15% of its electricity (89 TWh). The country is also one of the world's largest uranium producers, from mines in northern Saskatchewan, and has nuclear fuel facilities for the preparation of CANDU fuel.

The great majority of nuclear capacity is in Ontario, with 16 reactors in operation at present and two others under refurbishment. Québec has one nuclear plant in operation, while New Brunswick has one unit currently shut down for refurbishment; other provinces have no nuclear capacity. New nuclear plants have been proposed in Ontario, Alberta, Saskatchewan and New Brunswick. However, a decision on new plants in Ontario, originally expected in 2009, has been put on hold by the provincial government. The other three provinces are at the preliminary stage in considering new nuclear capacity.

NUCLEAR TECHNOLOGY

The first CANDU power reactor, a 22-MW prototype, began operating in 1962. The first large-scale CANDU, a 206-MW plant, followed in 1967. Subsequently, a total of 22 commercial CANDUs have been constructed in Canada, with others being exported to Argentina, China, Korea and Romania. The technology was also exported to India and Pakistan in the 1960s.

The design of CANDUs differs in several important respects from the light water reactors (LWRs) that comprise the bulk of nuclear plants worldwide. The use of heavy water as a moderator allows the use of natural uranium dioxide (UO_2) fuel, removing the need for uranium enrichment. The reactor itself comprises a horizontal cylindrical tank or "calandria" containing the heavy water moderator, through which pass several hundred horizontal fuel channels, each containing several fuel bundles. Heavy water coolant is pumped through the fuel channels. One advantage of the design is that it allows on-load refuelling, one fuel channel at a time, whereas LWRs must periodically shut down for refuelling.

The existing CANDU reactors can operate for around 25 to 30 years, at which point they require a major refurbishment (involving a lengthy shut-down). Once refurbished, they should be able to operate for a further 25 to 30 years.

However, the refurbishments carried out so far have taken longer and been more expensive than expected. To date, only two units have undergone this process and re-entered operation, with three more currently shut for refurbishment (see Table 17). The remaining units will require refurbishment over the next decade, and decisions on several of these will need to be taken in the near future.

Atomic Energy of Canada Limited (AECL) is currently marketing its 1 200 MW advanced CANDU design, known as ACR-1000, in Canada and elsewhere. Although this retains the calandria design and heavy water moderation, it differs from established CANDUs in using low enriched uranium fuel and light water coolant. AECL has also developed an enhanced version of the established CANDU 6 design, offering units in the 700 MW range. However, no orders for these new designs have yet been secured.

Table 17

Canada's Nuclear Power Station Refurbishment Plans

Station	*Operator*	*Unit*	*Power (MW_e)*	*Present status*	*Original start-up*	*Refurbishment Shut*	*Refurbishment Restart*
Pickering A	OPG	1	515	Operational	1971	1997	2005
		2	515	Shut down	1971	1997	–
		3	515	Shut down	1972	1997	–
		4	515	Operational	1973	1996	2003
Pickering B	OPG	5	516	Operational	1982	Under consideration (2012 to 2017 timeframe)	
		6	516	Operational	1983		
		7	516	Operational	1984		
		8	516	Operational	1986		
Bruce A	Bruce Power	1	750	Refurbishment	1977	1997	2011*
		2	750	Refurbishment	1977	1995	2011*
		3	750	Operational	1978	Expected to follow units 1 and 2	
		4	750	Operational	1979		
Bruce B	Bruce Power	5	795	Operational	1984	Under consideration (2013 to 2019 timeframe)	
		6	822	Operational	1985		
		7	822	Operational	1986		
		8	795	Operational	1987		
Darlington	OPG	1	881	Operational	1990	Under consideration (2018 to 2022 timeframe)	
		2	881	Operational	1990		
		3	881	Operational	1992		
		4	881	Operational	1993		
Gentilly	Hydro-Québec	2	635	Operational	1983	2011*	2012*
Point Lepreau	NB Power	–	635	Refurbishment	1983	2008	2010*

* expected date.

Sources: AECL, OPG, Bruce Power, Hydro Québec, NB Power.

INSTITUTIONAL ARRANGEMENTS

Natural Resources Canada (NRCan) is the federal government department with responsibility for nuclear policy. However, as described in Chapter 10, electricity markets in Canada are regulated by the provinces. Each province takes its own decisions on major investments in generating capacity, including nuclear plants. Hence, the federal government has a limited role in decisions on construction of new nuclear capacity, or on the refurbishment of existing units. Nevertheless, once a decision is taken by a province to go ahead with a nuclear project, the federal government has an important role in ensuring an efficient regulatory process.

Nuclear licensing and regulation is exclusively handled at federal level, through the Canadian Nuclear Safety Commission (CNSC). This is governed by the Nuclear Safety and Control Act of 2000. New legislation introduced since the last nuclear power plant was built remains to be tested in the process of licensing a new nuclear power plant. There is also no experience in Canada of licensing a non-CANDU plant. The licensing process contains several steps, including site preparation, construction, operation and decommissioning. The CNSC also conducts "pre-project design reviews" at the request of vendors, although these are not a formal part of the licensing process. Several such reviews are currently under way.

The federal government shares responsibility with the provinces for environmental assessments. This double layer of regulation can make the approvals process unnecessarily onerous. However, Ontario has agreed to accept the federal environmental assessment of nuclear projects rather than conduct its own separate review. The federal government's new Major Projects Management Office (MPMO) will be available to assist nuclear projects through the federal and provincial approval processes, including environmental assessments and nuclear licensing.

Atomic Energy of Canada Limited (AECL) is a federal Crown corporation established in 1952, which reports to the Canadian Parliament through NRCan. It developed the CANDU technology, and designed and built (with industrial partners) all the country's nuclear plants. It also provides maintenance and refurbishment services for CANDU plants. In addition, AECL operates the country's nuclear research sites, located at Chalk River, Ontario, and Whiteshell, Manitoba. There is also a substantial domestic (mainly Ontario-based) nuclear engineering industry, including Canadian subsidiaries of Babcock & Wilcox, General Electric and Hitachi.

In November 2007, the federal government began a review of AECL to consider whether the company's current structure was suited to its present role and best enabled it to take advantage of commercial opportunities in Canada and abroad. Completed in May 2009, the review noted AECL's strong industry credentials, intellectual property and skilled workforce. It concluded that the corporation's current mandate and structure limit its success and development, and that restructuring would help to maximise benefits for Canada. The review found significant private-sector interest in AECL's commercial operations, principally comprising the CANDU Reactor Division. It also found private-sector interest in new models or partnerships for the management of the Research and Technology Division, including the Chalk River Laboratories.

In response to the review, the government engaged N.M. Rothschild & Sons to develop a restructuring plan and provide financial advice. In addition, a special advisor to the Minister of Natural Resources was appointed to work with NRCan, AECL and the financial advisors. Rothschild submitted a financial analysis report on the restructuring of AECL to the government in October 2009. This envisaged that the CANDU Reactor Division would become a separate corporate entity, provisionally known as CANDU Inc., to facilitate third-party investment in the business.

In December 2009, the government issued an invitation to potential investors to make proposals that would allow the CANDU reactor business to take advantage of commercial opportunities in Canada and other countries, while reducing the risks carried by taxpayers. The government will assess how well the proposals received meet its aims of preserving the Canadian nuclear industry and the employment it provides, and of controlling costs and achieving maximum value for taxpayers. It was also announced that a decision on how to proceed with restructuring the Research and Technology Division would be taken at a later date.

NUCLEAR POWER PLANTS

ONTARIO

Nuclear power plays a key role in Ontario, with three multi-unit nuclear sites providing over 50% of the province's electricity. A total of sixteen CANDU reactors are currently in operation, with a further two undergoing refurbishment. Ontario Power Generation (OPG), a corporation wholly owned by the provincial government, owns all three nuclear sites and operates two of them (Pickering and Darlington). The third site (Bruce) is leased to a private-sector consortium which operates the site, selling power to OPG and other customers under long-term contracts. The operating performance of the existing nuclear fleet has improved notably in recent years, with higher load factors now being achieved.

The earliest nuclear power station is at Pickering, on the northern shore of Lake Ontario, about 30 km east of Toronto. The four older units, known as Pickering A, were taken out of service in 1996/97. Units 1 and 4 were subsequently refurbished and returned to service in 2005 and 2003, respectively. However, given the higher-than-expected costs involved in refurbishing these units, in 2005 OPG decided that refurbishment of units 2 and 3 was unlikely to be economic; these two units are now expected to be defuelled in preparation for decommissioning. In 2006, OPG launched a study of the possible refurbishment of the four Pickering B units, with a view to extending their life beyond the current end date of 2016. A decision is expected in the near future.

The four-unit station at Darlington is Canada's newest nuclear plant, with the largest CANDU units built to date. It is also located on the northern shore of Lake Ontario, some 70 km from Toronto. The four units started up between 1990 and 1993. They are expected to require refurbishment around 2018.

The Bruce site is located on the eastern shore of Lake Huron, near Kincardine, some 250 km from Toronto. The older four units, known collectively as Bruce A, were taken out of service between 1995 and 1998 by the then operator, Ontario Hydro (predecessor to OPG). In 2001, the Bruce site was leased by the OPG to a private-sector operating company, Bruce Power, currently owned jointly by TransCanada Corporation (31.6%), Cameco Corporation (31.6%), BPC Generation Infrastructure Trust (31.6%) owned by a pension fund, and two trade unions (5.2%). The lease lasts for 18 years, with an option to extend for up to a further 25 years. It includes terms for the purchase by OPG of the power output from the station. Bruce Power successfully restarted units 3 and 4 in 2004 and 2003 respectively.

In 2005, an investment programme for the refurbishment and restart of Bruce A units 1 and 2, and the follow-on refurbishment of units 3 and 4, was agreed with the Ontario government. A separate entity was established to undertake this programme, which does not include Cameco. TransCanada and BPC each hold 47.4% of this entity, with 5.2% held by the two trade unions. The agreement includes improved terms for the purchase by OPG of power from Bruce A. Bruce Power and the provincial government are also studying the feasibility of refurbishing the four Bruce B units, with a decision expected in the near future.

The provincial government's Integrated Power System Plan envisages maintaining nuclear capacity at its present level of about 14 000 MW (a figure that includes the two shut-down Pickering A units) through 2025. This implies the refurbishment of additional reactors and the construction of new capacity to replace those plants that are not refurbished.

In 2006, the provincial government instructed OPG to begin the licensing process for two additional nuclear units, with a planned start-up date of 2018. In 2008, the Darlington site was named as the location for these new units and Infrastructure Ontario, an agency of the provincial government, launched a competitive procurement process to select a supplier. For the first time, vendors other than AECL were invited to submit proposals for new units in

Canada. On the basis of an initial assessment, three companies were invited to submit a detailed proposal for their particular reactor design: AECL for the ACR-1000, AREVA for its US-European pressurised water reactor design, and Westinghouse for the AP-1000. The main items to be considered were lifetime generation costs, the ability to deliver the plants on time, and the level of investment to be made in Ontario. The willingness of the potential vendors to take on a large share of the financial risks of construction was also a factor considered by the province.

In February 2009, it was announced that all three invited companies had submitted proposals, which were under review. However, in June 2009 the provincial government announced that it had suspended the selection process. It also stated that only the AECL bid had satisfied all the province's requirements, but that the costs involved were unacceptably high. It also noted the uncertainty about AECL's future created by the federal government's announcement about restructuring the company.

OPG has nevertheless continued with its activities related to licensing the proposed new plants, and in September 2009 submitted an environmental impact statement and application for a site preparation licence. In the same month, the Canadian Nuclear Safety Commission (CNSC) completed phase 2 of the pre-project design review of the ACR-1000.

Separately, Bruce Power had submitted site preparation licence applications to build up to four new nuclear units, two at the Bruce site and two at Nanticoke on the north coast of Lake Erie. However, in July 2009, the company announced that it was withdrawing these applications, citing falling electricity demand and its desire to focus on the refurbishment of the existing Bruce A and B units.

OTHER PROVINCES

In **New Brunswick**, provincial utility NB Power has a single nuclear unit at Point Lepreau, on the Atlantic coast about 40 km from Saint John. In operation since 1983, it provides up to 30% of the province's electricity. In March 2008 the plant closed down for refurbishment to provide it with a further 25 to 30 years of operating life. The shut-down was expected to take about 18 months, but in September 2009 it was announced that restart was expected in October 2010.

New Brunswick is an important provider of power to neighbouring provinces and also to the New England region of the United States. The provincial government has aims to further develop the province as an "energy hub". As part of this strategy, consideration is being given to the possibility of adding a second reactor. In 2007, an industry group led by AECL was invited to prepare a feasibility study for an ACR-1000, and in parallel the province commissioned a consultant's report on the viability of such a project. These reports are now with the provincial government.

In **Québec,** Hydro-Québec has a single operating nuclear plant at Gentilly, on the St Lawrence River near Bécancour, that provides about 3% of the utility's output. The plant, which is of the same design as the Point Lepreau plant, has also been in operation since 1983. In August 2008 the company announced its intention to refurbish the unit to allow operation until around 2040. This is expected to involve closing the reactor for approximately 20 months, with restart in late 2012. There are no plans for additional nuclear capacity in Québec.

Bruce Power has expressed interest in constructing nuclear plants either in Alberta or in Saskatchewan, or both. **Alberta** has recently indicated that nuclear may be part of the energy mix for the province. As such, proposals funded by proponents may be considered by the Nuclear Safety Commission. Saskatchewan, on the other hand, has delayed any consideration of nuclear until after 2020. In Alberta, an important incentive is the need for energy for the extraction of oil from oil-sands, while limiting carbon dioxide emissions. Bruce Power has identified a site to the north of Peace River for a 3 200 to 4 400 MW nuclear station with two to four units, and has begun work on environmental assessments. The tentative schedule is to begin construction in 2012. In 2008, the province established an expert panel to report on issues related to hosting a nuclear plant. The publication of the panel's report in March 2009 was followed by a public consultation process. The consultation report released in December 2009 outlined the government of Alberta's position on individual projects being considered by the Safety Commission.

In **Saskatchewan**, Bruce Power issued a feasibility study in 2008 that envisaged 1 000 MW of nuclear capacity in the province by 2020. In the same year, the provincial government commissioned a report on how it could take greater advantage of its position as leading uranium-producing region. This could include involvement in other areas of the nuclear fuel cycle, as well as hosting a nuclear power plant. The report was issued in March 2009, recommending that the province include nuclear as part of its long-term energy strategy. However, it recognised that the province's small population means that a nuclear plant would probably need to serve other markets, such as neighbouring Alberta, to be feasible.

NUCLEAR FUEL CYCLE AND RADIOACTIVE WASTE

The country was for many years the world's largest uranium producer, accounting for about 20% of world production in 2008. Over 80% of this is exported. However, output has been declining in recent years, and in 2009 Canada was the second-largest producer after Kazakhstan.

Current production is from three mines in northern Saskatchewan: McArthur River (the world's largest uranium mine) and Rabbit Lake operated by Cameco Corporation, and McClean Lake operated by AREVA Resources Canada Inc. (a subsidiary of the AREVA Group of France). Cameco is developing a new mine at Cigar Lake, but flooding has delayed production by several years, to 2013 at the earliest. There are other known deposits that could start production before 2020, in Saskatchewan and also in Nunavut, Québec and Labrador, but none are currently under development. Production is thus not expected to increase significantly until Cigar Lake enters operation.

Ontario hosts a large nuclear fuel-processing industry. Cameco operates a uranium refinery (producing uranium trioxide, UO_3, from uranium concentrate) at Blind River, and a uranium hexafluoride (UF_6) conversion plant at Port Hope (which produces about 25% of the global supply of UF_6, used to prepare enriched fuel for light-water reactors). The latter site also produces uranium dioxide (UO_2) for the fabrication of CANDU fuel. Fabrication itself is carried out both by Cameco (also at Port Hope) and by GE-Hitachi Canada at its Peterborough site. All fuel for Canadian reactors is supplied from these domestic facilities.

In 2006, the government adopted the Nuclear Legacy Liabilities Program, a long-term strategy for the management of radioactive wastes and other nuclear liabilities (including disused facilities and buildings) at AECL research sites. Funding was provided for an initial five-year phase of the programme.

Separately, the Low-Level Radioactive Waste Management Office is responsible for historic low-level radioactive waste across Canada, for which the federal government has accepted responsibility. The Office is operated by AECL under a cost-recovery agreement with NRCan. Historic waste from early uranium mining in Port Hope, Ontario, is being managed through a dedicated office established in 2009. In 2006, the federal government and the Saskatchewan provincial government agreed to share costs for the remediation of early uranium mining sites in that province.

OPG operates the Western Waste Management Facility (WWMF) near the Bruce plant for the storage of low- and intermediate-level operational wastes from its nuclear power plants. In consultation with the local authority, OPG is proposing to construct a deep geological repository at the WWMF site for the long-term storage of these wastes. The project is undergoing an environmental assessment. NB Power and Hydro-Québec operate solid radioactive waste management facilities at Point Lepreau and Gentilly to handle their low- and intermediate-level wastes.

The Nuclear Waste Management Organization (NWMO) was established by OPG, Hydro-Québec and NB Power in accordance with the Nuclear Fuel Waste Act of 2002. The NWMO is responsible for the long-term management of the country's irradiated nuclear fuel, from both commercial and research reactors, which is currently stored at reactor and research sites. In 2007, the federal government selected the NWMO's recommendation for "Adaptive Phased Management" of irradiated nuclear fuel over the long term. The end-point of this plan is to construct and operate a deep geological repository at a suitable site within a willing host community. The NWMO is responsible for implementing the plan, under government oversight.

CRITIQUE

Given that electricity supply is a matter for the individual provinces, the federal government only plays a supporting role in decisions on new nuclear capacity. However, it does have an important role as the owner of AECL. The company has been a significant global nuclear power plant vendor, and it has continued to develop its unique technology with its latest reactor designs. But in recent years, the international nuclear industry has undergone substantial consolidation, and AECL's status as a Crown corporation has prevented it from playing a role in this. It now finds itself a relatively small player on the global stage, competing with larger and better resourced companies (including in its home market). Following a review, the government has announced its intention to restructure the company to allow it to better develop its commercial activities, while maintaining its nuclear R&D activities and its role in helping manage the nation's radioactive waste and other nuclear liabilities. This is to be welcomed, and the government is encouraged to proceed with this restructuring at an early stage.

Since the last in-depth review in 2004, interest in the construction of new nuclear plants in Canada has increased markedly, with plans being considered in Ontario, Alberta, Saskatchewan and New Brunswick. However, the decision of the Ontario government to suspend the procurement process for two new plants was a significant setback. The province effectively selected AECL as its preferred vendor, but found the cost of the present proposal too high. As the new plants would be the first-of-a-kind project for the ACR-1000, the financial risks would be relatively high, and the costs would to a significant extent depend on the risk-sharing model adopted. This puts the onus on the federal government, as the owner and ultimate financial backer of AECL, to take a share of the financial risk. The prospects for a restructuring of AECL that involves some form of private-sector investment will clearly be much improved if the company has a confirmed order for its ACR-1000 design.

Major refurbishments of some of the older units to extend their operating lives are continuing. However, these refurbishments, including those currently under way, have suffered delays and cost overruns. Two of the older units have been permanently closed down as their refurbishment was deemed uneconomic. Decisions will need to be taken soon on the refurbishment of a further eight units in Ontario, which will represent a significant investment in maintaining the province's nuclear capacity. AECL is the main contractor for the refurbishment of older plants. Hence, the proposed restructuring of the company may also have an important impact here.

Another important federal responsibility in the development of new nuclear capacity is for the licensing and regulatory processes, both nuclear licensing (through the Canadian Nuclear Safety Commission) and environmental assessments. The CNSC has taken steps to streamline the nuclear licensing process. However, as no new plant construction has been licensed since the 1980s, and the relevant legislation has changed, complications and delays cannot be ruled out. For environmental assessments, avoiding an onerous double layer of federal and provincial approvals is an important aim. The government has established the MPMO with the aim of facilitating regulatory review of major resource projects, including the licensing and environmental approvals of new nuclear plants, but its effectiveness has not yet been demonstrated.

RECOMMENDATIONS

The government of Canada should:

- *Provide support and encouragement for the deployment of new nuclear capacity in those provinces which decide to pursue nuclear programmes, especially those planning to host their first nuclear plants.*
- *Carry out the proposed restructuring of Atomic Energy of Canada Limited (AECL), with the aim of ensuring that the company has the resources to complete the development of the new advanced CANDU design and to pursue its other commercial activities in the domestic and international markets, while maintaining vital nuclear R&D and radioactive waste management activities, in particular to support the refurbishment and improved operation of the existing nuclear fleet.*
- *Monitor the functioning of the nuclear and federal environmental regulatory processes, and the effectiveness of the Major Projects Management Office (MPMO) in supporting nuclear projects through these processes; if necessary, act to ensure that new nuclear plant construction does not suffer undue licensing delays.*

PART III

ENERGY TECHNOLOGY

ENERGY TECHNOLOGY RESEARCH AND DEVELOPMENT

OVERVIEW

The main focus of Canada's energy research and development (R&D) activities is to sustainably produce and use/export Canada's energy resources This will be achieved through the use of technologies and systems for the production and use of energy that respect the environment and are sustainable for future generations, in particular by reducing GHG emissions, within the scope of a market-driven economy accompanied with intervention in areas of strategic national interest.

Public funds are provided by federal programmes as well as by provincial governments. Furthermore, because of the federal government's interest in practical solutions and economic applications, privately initiated R&D activities are encouraged, and those that complement the government's goals are funded primarily through private-public partnerships, *i.e.* federal and provincial governments working with private-sector firms and consortia

Federal energy R&D is planned and conducted with energy policy guidance from Natural Resources Canada (NRCan). Nuclear fission R&D, except for Generation IV technology, is separate from other federal energy R&D programmes, and is conducted by Atomic Energy of Canada Limited (AECL). AECL reports to the Minister of NRCan.

The federal government funds energy R&D by means of five mechanisms:

- Energy R&D dedicated programmes: NRCan's energy research laboratories which receive funds from the Program of Energy Research and Development (PERD) to augment their base budgets, and AECL which performs nuclear fission research related to power generation and other applications;
- Federal departmental laboratories that perform R&D in other fields, such as environmental protection, but that include an energy R&D component (their energy R&D is augmented by PERD);
- Programmes that cover a number of fields but can include energy R&D, including university grants through the Natural Sciences and Engineering Research Council (NSERC);
- R&D tax credits which apply to all R&D, including energy; and
- Climate change initiatives which include substantial energy R&D, including through federally funded organisations outside government.

Other federal government institutions not focused on energy may fund some energy-related research projects. The most significant of which are the National Research Council and NSERC.

Canada's research activities are well integrated with international collaborations on a bilateral and multi-lateral level, for example with the United States and with the International Energy Agency's R&D efforts. Its international energy R&D policy and collaboration are guided by the objective of accelerating and leveraging research, development and demonstration that advance national objectives, and contribute to international efforts.

Canada participates in 31 of the 41 IEA Implementing Agreements (IA), in all Working Parties, the IEA Expert Group on Science and Energy, the International Partnership on Energy Efficiency (IPEEC), the Asia-Pacific Economic Cooperation's Energy Working Group (APEC EWG), the Carbon Sequestration Leadership Forum (CSLF), the Global Carbon Capture and Storage Institute (GCCSI), the Asia-Pacific Partnership on Clean Development and Climate (APP), the International Partnership for a Hydrogen Economy (IPHE), the North America Energy Working Group (NAEWG), the Global Bio-Energy Partnership (GBEP), and the Generation IV International Forum (Gen IV).

Additionally, the recently announced United States-Canada Clean Energy Dialogue will review the existing forms of collaboration and identify high-return opportunities for expanded and new joint research related to advanced biofuels, clean engines, energy efficiency, carbon capture and storage (CCS) and smart grid technologies and strategies. Canada also participates actively as the lead author in developing a Technology Action Plan on advanced vehicles and as a contributor under this activity under the Major Economies Forum (MEF) which looks at a number of energy technologies and at the degree and scale of overall technology effort required and how to accelerate results.

MANAGING ENERGY R&D

NATURAL RESOURCES CANADA (NRCan)

The role of the federal government is not only to provide funding but also to act as a leader, co-ordinator and facilitator of R&D with all stakeholders. NRCan's role is to complement the efforts of the provinces and industry. The general thrust of the federal effort has been towards greater integration of science and policy, with greater concentration on applied research and technology development in co-operation with private-sector partners. Canada's energy R&D framework is a challenge given the diversity of Canada's resource base, the various provincial priorities, and the need to prioritise support for promising opportunities with limited funding.

In developing its R&D strategy, recommendations from expert bodies have been sought. These expert bodies include; the National Round Table on the Environment and Economy (NRTEE), the Canadian Academy of Engineers (CAE), the National Advisory Panel on Sustainable Energy, Science and Technology (NAP), the Energy Technology Working Group of the Council of Energy Ministers, and the Energy Dialogue (between the United States and Canada).

As a result, NRCan's energy R&D programme is organised into nine portfolios, each with an interdepartmental management committee, an external advisory committee, and an extensive national network. This co-ordinative effort is overseen by NRCan. The nine portfolios are:

- Bitumen, Oil and Gas;
- Frontier Oil and Gas;
- Clean Coal and Carbon Capture and Storage;
- Distributed Power Generation;
- Next Generation Nuclear (Generation IV);
- Bio-based Energy Systems;
- Low Emission Industrial Systems;
- Clean Transportation Systems;
- Built Environment.

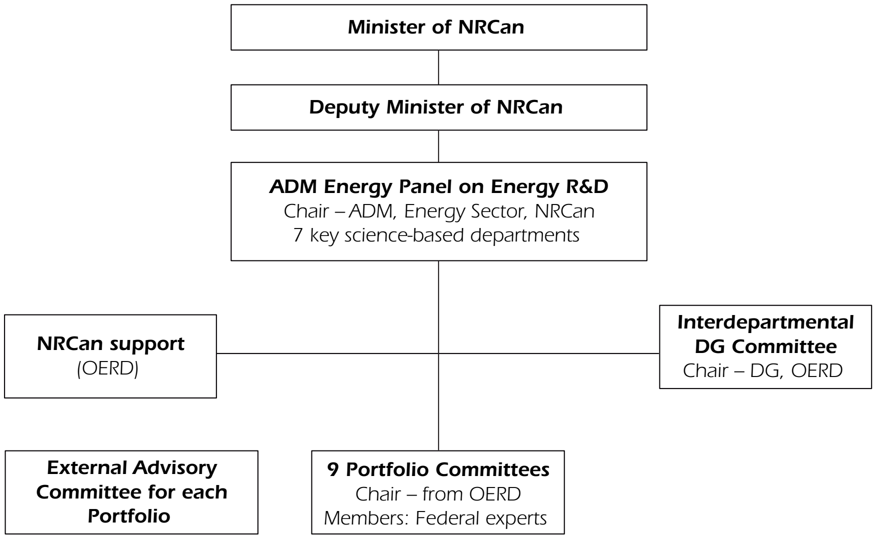
NRCan funds and manages three energy-focused interdepartmental programmes – the Program of Energy R&D (PERD), the ecoENERGY Technology Initiative (ecoETI) and the Clean Energy Fund (CEF). These programmes are interdepartmental, in that funds flow to NRCan and other participating federal departments and agencies (and in the case of ecoETI and CEF, to targeted private industries), with an interest in energy-related R&D to augment their base of energy resources. These ministries and agencies include:

- Industry Canada;
- Environment Canada;
- Agriculture and Agri-Food Canada;
- Defence Research and Development Canada;
- Health Canada;
- Public Works and Government Services Canada;
- National Research Council; and
- Atomic Energy of Canada Limited.

An interdepartmental committee comprised of Assistant Deputy Ministers (ADM) oversees the management of the three programmes. Figure 41 illustrates the structure employed by NRCan to manage its energy R&D activities.

Figure 41

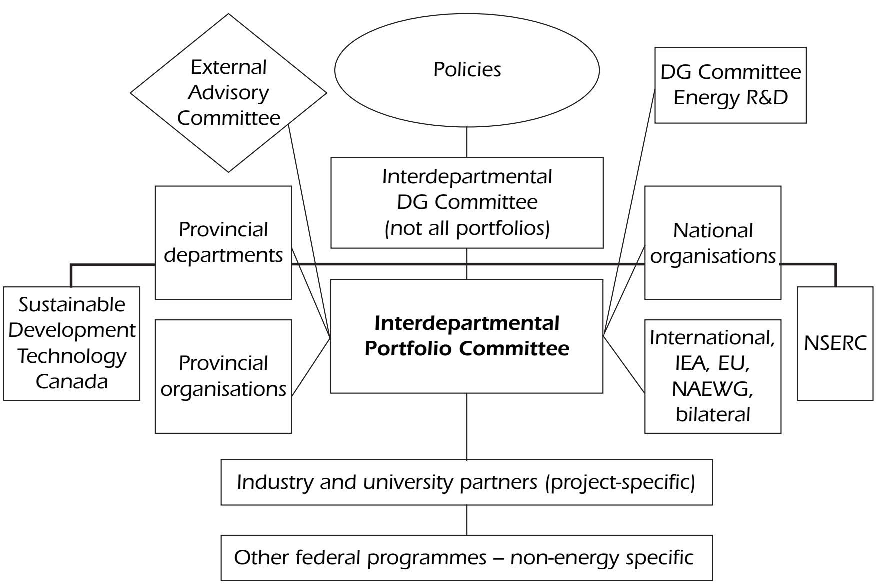
NRCan's Energy R&D Management



Source: NRCan.

Figure 42

NRCan Energy R&D Co-ordination



NSERC: Natural Sciences and Engineering Research Council. NAEWG: North America Energy Working Group.
Source: NRCan.

Energy R&D programmes are co-ordinated under NRCan's leadership and managed by its Office of Energy Research and Development (OERD). Co-operation with provinces is overseen by the Council of Energy Ministers (CEM, with the federal, provincial and territorial energy ministers) and the Energy Technology Working Group (ETWG) under the CEM. The ETWG is co-chaired by NRCan and the province of Alberta. NRCan serves as the primary co-ordinator for national R&D activities. The overall process to allow for co-ordination and networking among federal agencies, provincial governments, industry and universities, is depicted in Figure 42.

ENERGY R&D FUNDING

The government of Canada's public energy R&D budget is large when compared to other IEA member countries. Compared to other developed countries, the Canadian energy R&D budget per thousand units of GDP was 0.44 in 2008, one of the highest among IEA members (Figure 44). In the 2008/09 budget, Canadian public investment in energy R&D was allocated such that 14% was spent in energy efficiency, 27% in fossil fuels, 11% in renewables, 38% in nuclear fusion and fission, 5% in hydrogen and fuel cells, and 5% in other power and storage, and other cross-cutting R&D. These proportions are relatively consistent with 2007/08 actual R&D expenditures.

Table 18

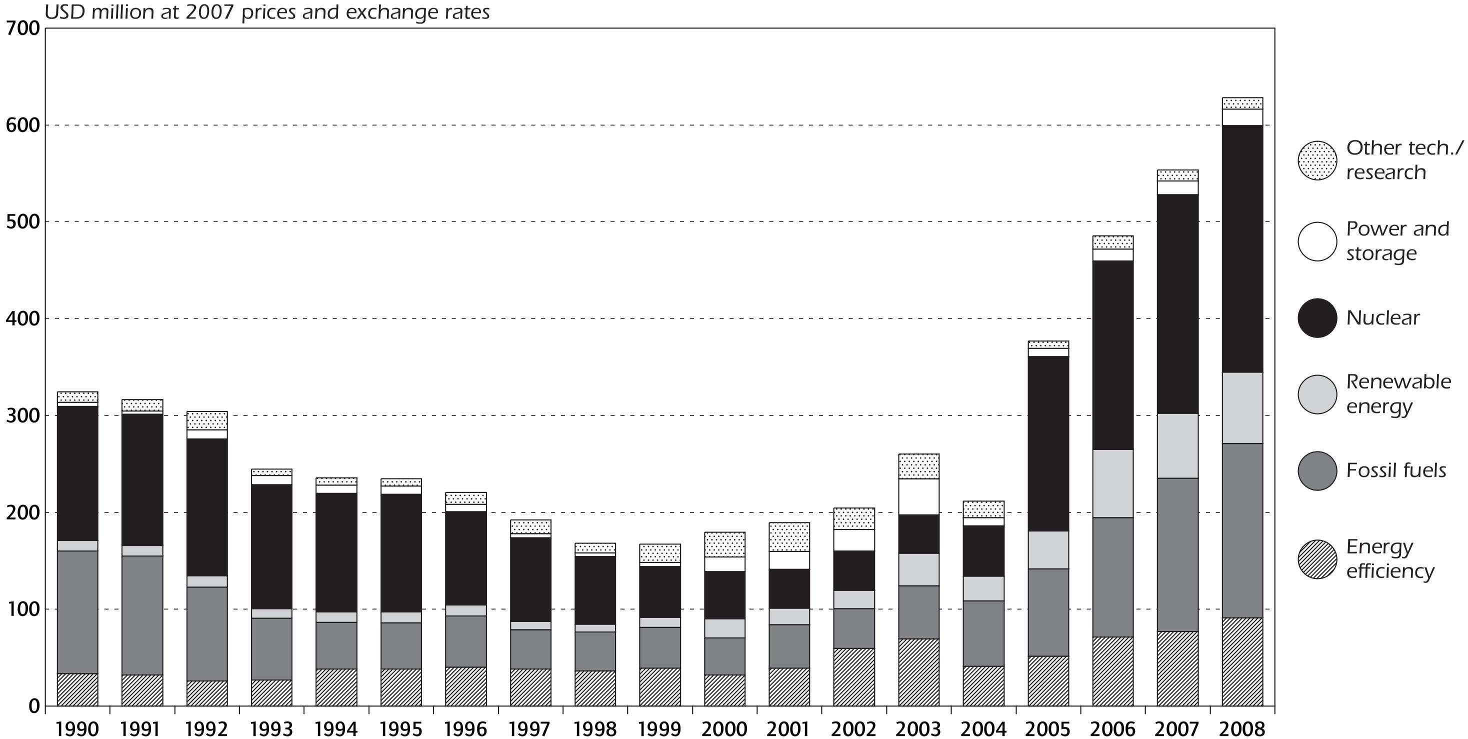
Estimated Federal Government Energy R&D Expenditures, 2008/09 (in thousand Canadian dollars)

Activities	*Federal*	*Provinces*	*Total*	*%*
Energy efficiency	90 499	6 736	97 236	14
Fossil fuels: oil, gas, coal	84 455	107 904	192 359	27
Renewable energy sources	51 458	27 338	78 796	11
Nuclear fission and fusion	271 666	26	271 692	38
Hydrogen and fuel cells	34 207	3 311	37 518	5
Other power and storage technologies	17 396	760	18 156	3
Other cross-cutting R&D	9 376	3 226	12 602	2
Total	**559 057**	**149 301**	**708 358**	**100**

Source: NRCan.

Figure 43

Government RD&D Spending on Energy, 1990 to 2008*

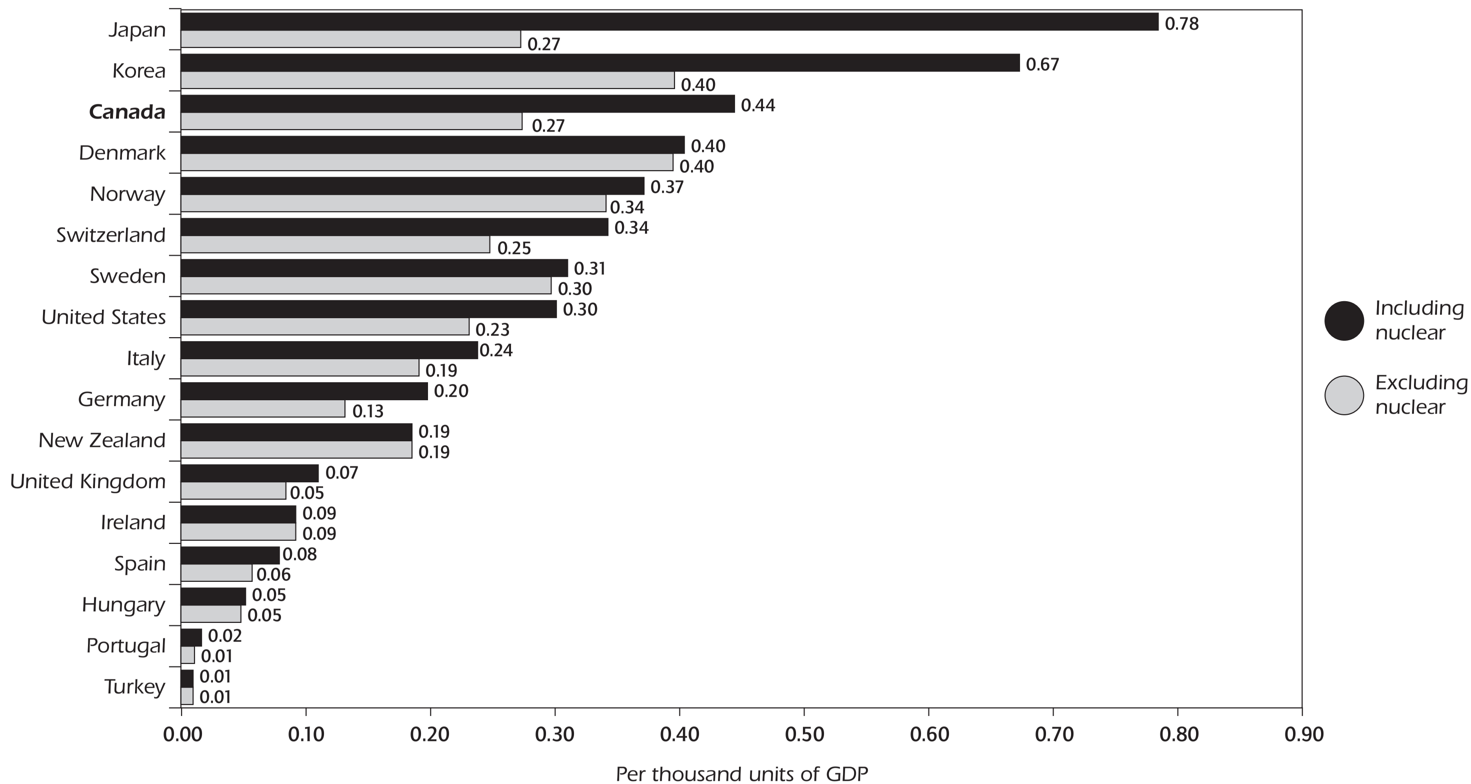


* 2008 = estimates.

Sources: *OECD Economic Outlook*, OECD Paris, 2009 and country submission.

Figure 44

Government R&D Budgets in IEA Member Countries, 2008*



* estimates.

Data not available for Australia, Austria, Belgium, the Czech Republic, Finland, France, Greece, Luxembourg, the Netherlands, Poland and the Slovak Republic.

Sources: *OECD Economic Outlook*, OECD Paris, 2009 and country submissions.

PROGRAM OF ENERGY RESEARCH AND DEVELOPMENT (PERD)

The Program of Energy Research and Development (PERD) is a federal, interdepartmental programme operated by Natural Resources Canada (NRCan). It is the ongoing base energy R&D programme in the federal government, whereas the other energy R&D programmes have fixed termination dates. PERD funds R&D designed to ensure a sustainable energy future for Canada in the best interests of the economy and environment. It directly supports 40% of all non-nuclear energy R&D conducted in Canada by the federal and provincial governments, and is concerned with all aspects of non–nuclear energy supply and use, with the exception of Generation IV nuclear technology.

PERD is primarily an applied research and technology development programme. It is implemented by Canada's three energy-focused CanmetENERGY research centres, located in Ottawa (Ontario), Devon (Alberta), and Varennes (Québec). Through its networks of federal energy R&D stakeholders, PERD funds research in universities, private-sector joint projects, grants and consortia, as well as joint efforts with the provincial governments.

Overall guidance on PERD is provided to NRCan by the interdepartmental committee comprised of Assistant Deputy Ministers from the principal federal R&D departments and agencies that perform or manage energy R&D and which have a policy interest in science and technology. This committee is responsible for bringing industrial, environmental and science policies to bear on energy R&D policy and strategic direction, and for setting PERD's strategy and priorities

The PERD programme is delivered interdepartmentally through the following departments and agencies, supporting NRCan's energy policies by a combination of departmental and PERD funds:

- Natural Resources Canada;
- National Research Council (NRC);
- Transport Canada;
- Fisheries and Oceans;
- Agriculture and Agri-Food Canada;
- Public Works and Government Services Canada;
- Health Canada;
- Environment Canada;
- Canada Mortgage and Housing Corporation;
- National Defence;
- Industry Canada;
- Atomic Energy of Canada Limited;
- Indian Affairs and Northern Development.

NRCan's Office of Energy R&D (OERD) administers PERD's annual budget of CAD 55 million (2008). Funding for PERD has remained constant over the years but is declining in real terms as new programmes have been added such as Generation IV nuclear and plug-in hybrids. Reductions have been made to energy efficiency in industry and hydrogen and fuel cells programmes. The addition of new programmes over the years is the result of the government's effort to increase the profile of its R&D support for key technology areas. For example, there has been greater concentration of funding for clean coal, CCS and oil-sands, and bioenergy activities. Nevertheless, the government has also had to maintain its R&D efforts in other areas of national interest such as nuclear, renewables, transport, energy end-use in buildings and industry. Future increased R&D levels should be considered to reverse this decline in real terms.

The general thrust of federal effort has been towards closer integration of science and policy, with a greater concentration on applied research and technology development in co-operation with private-sector partners. However, there is also a greater push on the science to understand the environmental and regulatory aspects in areas of need.

ecoENERGY TECHNOLOGY INITIATIVE (ecoETI)

In addition, NRCan's Office of Energy Research and Development also administers the ecoETI a five-year programme with CAD 230 million funding. This initiative succeeded the Technology and Innovation programme, which ended in 2008. The ecoETI is a five-year sunset programme to fund research, development and demonstration of clean energy technologies. This initiative is being delivered as a single, integrated programme – research, development and demonstration – covering the innovation spectrum from basic research to the early commercialisation of technologies. The programme is focusing on priority technology areas to support the development and demonstration of the next generation of clean energy technologies – technologies that currently do not exist, or that are at a very early stage of development. This initiative targets all sources of clean energy, including renewable energy sources.

The initiative has committed a larger portion of the funding to two areas: technology development to reduce the environmental impact of oil-sands; and carbon capture and storage technologies to reduce greenhouse gas emissions from large point sources such as coal-fired plants and oil-sands.

CLEAN ENERGY FUND

Launched in May 2009 by the Minister of Natural Resources, the Clean Energy Fund (part of the government of Canada's 2009 Economic Action Plan) will invest CAD 850 million over five years in technology development and demonstration, of which CAD 650 million for large-scale CCS demonstration projects and CAD 200 million for smaller-scale demonstration projects of renewable and alternative energy technologies. CCS projects will be co-funded by the Clean Energy Fund and provincial CCS programmes. There will also be a CAD 150 million research component. Investments made through the Clean Energy Fund will also support Canada's work with the United States in building a cleaner energy economy for North America through the Canada–United States Clean Energy Dialogue. In addition to federal funding, the government of Alberta has also committed CAD 2 billion to CCS-related activities.

NUCLEAR R&D

Public nuclear R&D is carried out by AECL, a Crown corporation owned and operated by the federal government. AECL is a nuclear technology and engineering company with global operations that designed and developed the CANDU nuclear power reactor, as well as other advanced energy products and services. It supports customers over the entire plant lifecycle from R&D, nuclear services, design and engineering, to construction management, specialist technology, and waste management and decommissioning.

The nuclear R&D budget (with the exception of the budget for Generation IV technology) has traditionally been, and continues to be, administered separately from other energy R&D programmes such as PERD and ecoETI. NRCan and the Treasury Board ensure an alignment of nuclear R&D to government objectives and priorities, and AECL manages the R&D programmes in consultation with other Canadian stakeholders.

PROVINCIAL AND TERRITORIAL GOVERNMENT R&D

Provincial and territorial governments also fund R&D activities. These activities are focused on their respective resources. Additionally, they will co-fund projects with either the federal government or with one another in areas of mutual interest. For example, the provinces of Alberta and British Columbia are engaged in studies to assess the potential development of an east-west pipeline and electricity grid, and both have strong interests in CCS that complement the goals of the Clean Energy Fund.

Table 19 provides reported 2008/09 RD&D expenditures by province. Alberta is the largest provincial funder of RD&D activities.

Energy RD&D is conducted in research centres across all provinces and includes such stakeholders as:

- Powertech Laboratories;
- Alberta Energy Research Institute;
- Petroleum Technology Alliance Canada;

- Manitoba Hydro;
- Hydro-Québec;
- Petroleum Research Atlantic Canada;
- CANDU Owners Group.

Table 19

Provinces Reporting RD&D Expenditures in Clean Energy Technology, 2008/09[1]

British Columbia [2]	*Alberta[2,3]*	*Ontario[2,4]*	*Québec[2]*	*Saskatchewan[2]*	*Prince Edward Island*	*Nova Scotia*	*New Brunswick*
CAD 45 M	*CAD 89 M*	*CAD 34 M*	*CAD 26 M*	*CAD 32 M*	*CAD 2.5 M*	*CAD 24 M*	*CAD 0.3 M*
Fuel cell and hydrogen (93%)	Oil and gas (72%)	Renewable (69%)	Renewable (bioenergy) (60%)	Oil and gas (49%)	Hydrogen (80%)	Oil and gas (78%)	Renewable (100%)
Power and storage (3%)	Coal (13%)	Energy efficiency (29%)	Energy efficiency (16%)	Coal (22%)	Renewable (wind) (12%)	Renewable (ocean) (22%)	
	CCS (7%)		Renewable (solar) (9%)	CCS (9%)			
	Renewable (bioenergy) (4%)			Energy efficiency (8%)			

[1] All utility RD&D expenditures are captured under industry expenditures.
[2] Have provincial R&D institutes.
[3] Does not include the Alberta announcement of CAD 2 billion for CCS projects;
[4] 2007/08 RD&D expenditures;
Source: NRCan.

In addition, all major Canadian universities have established, or are establishing, energy institutes. University funding comes from federal and provincial governments.

PRIVATE-SECTOR R&D

Private-sector expenditure on R&D is approximately double the amount of public-sector funding on an annual basis and is on the order of approximately CAD 1 billion. The major areas of private-sector energy R&D continues to reflect the largely commodity-based nature of the natural resources sector in Canada and includes oil and gas (oil-sands, enhanced oil recovery, sour gas, pipelines), electricity (hydro-turbines, transmission and distribution, CANDU nuclear technology, CCS), renewables (biomass gasification and combustion, wind forecasting, bioethanol and biodiesel), and efficient end-use of energy (alternative fuels, process integration and optimisation, plug-in hybrid electric vehicles, air quality).

CRITIQUE

Canada's R&D budget has continued to rise to meet changing national priorities in energy security and sustainable development. While the Technology and Innovation programme ended in 2008, it has been followed by the ecoETI with more funds focused primarily on clean coal and oil-sands technology demonstration and the CAD 1 billion Clean Energy Fund. The federal government also added CAD 500 million for the demonstration of second-generation biofuels and advanced heavy oil and oil-sands production technologies, which is managed by Sustainable Development Technology Canada (SDTC, a third-party foundation).

Canada spent about 0.3% of its GDP on non-nuclear R&D in 2007, placing it among the highest spending OECD members. This level of spending has been increasing in recent years to reflect Canada's energy diversity and national energy objectives. It is arguable, however, that an even higher level of spending would better reflect Canada's status as a leading energy producer and this should be considered by the Canadian government. Canada participates in a large number of international initiatives and R&D collaboration and this is welcomed.

The primary funding for the federal government's R&D programmes consists of:

- the Program on Energy Research and Development, PERD (CAD 55 million annually);
- the ecoETI (CAD 230 million over five years); and
- the Clean Energy Fund (CAD 1 billion over five years).

This continued upward trend in research, development and demonstration budget allocations is encouraging, and for this the Canadian government should be commended. Despite the upward trend in national R&D budgets, we note that the PERD budget has remained constant even as new programmes have been added in Generation IV nuclear, plug-in hybrid vehicles and gas hydrates.

The role of the federal government is not only to provide funding but also to act as a leader, co-ordinator and facilitator of R&D with all stakeholders. This co-ordination role has its challenges and the federal government (NRCan) is to be commended for taking an active leadership role. We note, however, that co-ordination between the provinces and industry is uneven with full co-ordination occurring primarily when the mutual interests of all parties intersect. Otherwise, we note that the provinces have no real incentives to co-ordinate R&D efforts with the federal government.

The federal government's energy R&D structure of nine portfolio areas is operating in a manner that allows for co-ordination, information-sharing and decision making. These nine portfolios were established on the basis of the national priorities established in the Federal Science and Technology strategy and the federal energy framework. There has been a greater concentration of government (federal and provincial) funding for nuclear energy, technology development and demonstration of clean coal, CCS, oil-sands and bioenergy. While this focus represents to a large extent the current priorities of the provinces and industry, we encourage the federal government to continue to assess its priorities and to expand or shrink its portfolio as national priorities change to meet future energy requirements. Two areas in which the federal government might consider further investments are its cross-cutting and other power and storage technology R&D activities. These two areas currently comprise only 5% of the total energy R&D budget. Advances in electricity storage and smart grids technology would benefit several industries where Canada is among global technology leaders.

RECOMMENDATIONS

The government of Canada should:

- *Continue to increase funding for research and development at federal level. Specifically, funding increases to the Program on Energy R&D budget should be considered, and dependence on short-term (typically five years) special programmes reduced.*
- *Continue to assess its RD&D priorities and to adjust its RD&D portfolio as national priorities change to meet future energy requirements.*

PART IV

ANNEXES

ORGANISATION OF THE REVIEW

REVIEW CRITERIA

The *Shared Goals*, which were adopted by the IEA Ministers at their 4 June 1993 meeting in Paris, provide the evaluation criteria for the in-depth reviews conducted by the IEA. The *Shared Goals* are presented in Annex C.

REVIEW TEAM

The in-depth review team visited Canada from 19 to 28 April 2009 and travelled to Ottawa, Toronto and Edmonton. The team met with federal government officials, representatives of provincial and territorial governments, energy producers and suppliers, interest groups and various other organisations. This report was drafted on the basis of these meetings and the federal government response to the IEA energy policy questionnaire and other information. The team is grateful for the co-operation and hospitality of the many people it met during the visit. Thanks to their openness and candour, the review visit was highly productive.

In particular, the team wishes to express its gratitude to Ms Sue Kirby, former Assistant Deputy Minister, Energy Sector, Natural Resources Canada and her senior staff, Mr. Kevin Stringer, Director-General, Petroleum Resources Branch, and Ms Kristi Varangu, Chief Multilateral Energy Relations, Petroleum Resources Branch, for their personal engagement in briefing the team on current national energy policy issues. Their willingness to share information and gracious hospitality contributed in no small way to a successful and productive visit.

The team is also grateful for the co-operation it received from the provinces of Ontario and Alberta, in particular from Mr Saad Rafi, Deputy Minister, Ontario Ministry of Energy and Infrastructure, government of Ontario, Ms Anne Denman, Executive Director, Oil Sands Operations, Department of Energy, government of Alberta, and Mr Mike Balfour, Director, Energy Economics, Ministry of Energy and Resources, government of Saskatchewan, who also participated in the provincial sessions. The team is also grateful for the assistance of Mr Brian Nicholson and Holly Metropolit of Department of Energy, government of Alberta for facilitating our visit to Edmonton.

The author is particularly thankful to Ms Stacy Burton and Ms Aruna Rajulu of Multilateral Energy Relations, Petroleum Resources Branch, for co-ordinating the team visit and their ongoing support throughout the drafting process.

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Kieran McNamara managed the review and drafted the report with the exception of Chapter 11 on Nuclear Energy, which was drafted by Martin Taylor and Chapter 12 on Energy Technology Research and Development, which was drafted by Steven Lee. Aad van Bohemen and James Simpson contributed on matters related to Emergency Preparedness in Chapter 8 on Natural Gas and Chapter 9 on Oil. Ulrich Benterbusch, Didier Houssin, Shinji Fujino, Grayson Heffner, Sara Moarif, Richard Baron, Anselm Eisentraut, Brian Ricketts, Tom Kerr, Anne-Sophie Corbeau, Julius Walker, Eduardo Lopez, Ricardo Crespo, Francois Nguyen and Rebecca Gaghen contributed helpful comments throughout.

Monica Petit and Bertrand Sadin prepared the figures. Karen Treanton and Alex Blackburn provided support on statistics. Muriel Custodio, Jane Barbière and Madeleine Barry managed the production process. Viviane Consoli provided editorial assistance. Marilyn Ferris helped in the final stages of preparation.

ORGANISATIONS VISITED

The team held discussions with the following energy and environment stakeholders:

- Natural Resources Canada (NRCan)
- The Department of Foreign Affairs and International Trade (DFAIT)
- Indian and Northern Affairs Canada (INAC)
- Environment Canada (EC)
- Provincial and territorial governments (via teleconference and in-person):
  - Alberta Department of Energy
  - Saskatchewan Ministry of Energy and Resources
  - Ontario Ministry of Energy and Infrastructure
  - Nova Scotia Department of Energy
  - New Brunswick Department of Energy
  - Nunavut Energy Secretariat
  - Yukon Department of Energy, Mines and Resources
  - Northwest Territories Department of Industry, Tourism and Investment
  - Québec Ministère des Ressources naturelles et de la Faune
  - Prince Edward Island Department of Environment, Energy and Forestry
  - Manitoba Department of Innovation, Energy and Mines
  - Newfoundland and Labrador Department of Natural Resources
  - British Columbia Ministry of Energy, Mines and Petroleum
- *Natural Sciences and Engineering Research Council (NSERC)*
- *National Research Council (NRC)*
- *Canadian Petroleum Products Institute(CPPI)*

- Canadian Gas Association (CGA)
- Canadian Electricity Association (CEA)
- Canadian Nuclear Association (CNA)
- Canadian Hydropower Association (CHA)
- Canadian Solar Industries Association (CANSIA)
- Canadian Wind Energy Association (CANWEA)
- Canadian Renewable Energy Alliance (CANREA)
- Pembina Institute
- Members of the Canadian Environmental Network (CEN) - Assembly of First Nations, Conserver Society of Hamilton and District, Environmental Health Association of Nova Scotia, Northwatch, National Council of Women of Canada
- Ontario Centre of Excellence for Energy
- Ontario Energy Board
- Ontario Independent Electric System Operator
- Ontario Power Authority
- Ontario Energy Association
- Association of Power Producers of Ontario
- British Columbia Department of Energy, Mines and Petroleum Resources
- Shell Canada- Scotford Upgrader
- Alberta Industrial Heartland Association
- Alberta Chamber of Resources
- Canadian Association of Petroleum Producers (CAPP)
- Canadian Society for Unconventional Gas
- Canadian Energy Pipeline Association
- Petroleum Technology Alliance Canada
- Alberta Energy Resources Conservation Board
- Alberta Utilities Commission (AUC)

ENERGY BALANCES AND KEY STATISTICAL DATA

Unit: Mtoe

SUPPLY		1973	1990	2000	2006	2007	2008P	2020
TOTAL PRODUCTION		**198.2**	**273.8**	**372.6**	**410.5**	**413.2**	**410.3**	**469.7**
Coal		11.7	37.9	34.4	32.4	33.9	33.5	33.3
Peat		–	–	–	–	–	–	–
Oil		96.5	94.1	128.4	155.3	160.9	164.7	229.9
Gas		61.4	88.6	148.3	154.9	150.6	143.6	130.0
Comb. Renewables & Waste[1]		7.8	8.3	11.6	11.7	11.5	11.1	17.0
Nuclear		4.1	19.4	19.0	25.5	24.4	24.5	23.2
Hydro		16.7	25.5	30.8	30.6	31.7	32.6	34.4
Wind		–	–	0.0	0.2	0.3	0.3	2.0
Geothermal		–	–	–	–	–	–	–
Solar/Other[2]		–	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL NET IMPORTS[3]		**–37.3**	**–61.1**	**–129.7**	**–141.9**	**–150.9**	**–140.7**	**–133.9**
Coal	Exports	7.6	21.4	19.3	16.8	18.0	18.4	14.5
	Imports	10.5	9.5	15.0	12.7	13.6	12.4	6.1
	Net Imports	2.8	–11.9	–4.2	–4.2	–4.4	–6.0	–8.4
Oil	Exports	63.2	49.7	93.3	116.1	120.3	119.8	114.3
	Imports	48.7	34.8	54.3	57.2	56.7	60.4	52.7
	Int'l Marine and Aviation Bunkers	–1.7	–1.8	–2.1	–1.4	–1.2	–1.1	–2.3
	Net Imports	–16.1	–16.7	–41.1	–60.3	–64.8	–60.5	–93.9
Gas	Exports	23.1	33.0	82.7	83.8	90.0	84.7	46.7
	Imports	0.3	0.5	1.3	7.9	10.2	12.8	16.4
	Net Imports	–22.8	–32.5	–81.3	–75.9	–79.8	–71.9	–30.3
Electricity	Exports	1.4	1.6	4.4	3.7	3.8	3.7	2.7
	Imports	0.2	1.5	1.3	2.0	1.7	1.4	1.5
	Net Imports	–1.2	–0.0	–3.1	–1.6	–2.2	–2.3	–1.2
TOTAL STOCK CHANGES		**–1.6**	**–4.0**	**8.2**	**0.5**	**7.1**	**3.1**	**–**
TOTAL SUPPLY (TPES)[4]		**159.3**	**208.7**	**251.2**	**269.2**	**269.4**	**272.7**	**335.9**
Coal		15.3	24.3	31.7	28.6	30.1	26.2	24.9
Peat		–	–	–	–	–	–	–
Oil		79.4	76.5	86.8	94.6	94.5	103.5	135.9
Gas		37.3	54.7	74.2	79.6	79.0	76.9	99.7
Comb. Renewables & Waste[1]		7.8	8.3	11.7	11.7	11.7	11.1	17.0
Nuclear		4.1	19.4	19.0	25.5	24.4	24.5	23.2
Hydro		16.7	25.5	30.8	30.6	31.7	32.6	34.4
Wind		–	–	0.0	0.2	0.3	0.3	2.0
Geothermal		–	–	–	–	–	–	–
Solar/Other[2]		–	0.0	0.0	0.0	0.0	0.0	0.0
Electricity Trade[5]		–1.2	–0.0	–3.1	–1.6	–2.2	–2.3	–1.2
Shares (%)								
Coal		*9.6*	*11.6*	*12.6*	*10.6*	*11.2*	*9.6*	*7.4*
Peat		–	–	–	–	—	–	–
Oil		*49.8*	*36.7*	*34.6*	*35.1*	*35.1*	*38.0*	*40.5*
Gas		*23.4*	*26.2*	*29.6*	*29.6*	*29.3*	*28.2*	*29.7*
Comb. Renewables & Waste		*4.9*	*4.0*	*4.7*	*4.4*	*4.3*	*4.1*	*5.0*
Nuclear		*2.6*	*9.3*	*7.6*	*9.5*	*9.0*	*9.0*	*6.9*
Hydro		*10.5*	*12.2*	*12.3*	*11.4*	*11.8*	*11.9*	*10.3*
Wind		–	–	–	*0.1*	*0.1*	*0.1*	*0.6*
Geothermal		–	–	–	–	–	–	–
Solar/Other		–	–	–	–	–	–	–
Electricity Trade		*–0.8*	–	*–1.2*	*–0.6*	*–0.8*	*–0.9*	*–0.4*

P: provisional data. 0 is negligible, – is nil. .. is not available.

Forecasts for 2030 are not available.

Unit: Mtoe

DEMAND

FINAL CONSUMPTION BY SECTOR

	1973	1990	2000	2006	2007	2008P	2020
TFC	**131.2**	**159.1**	**189.7**	**196.8**	**205.0**	**207.0**	**258.9**
Coal	5.2	3.1	3.5	3.6	3.6	4.7	5.2
Peat	–	–	–	–	–	–	–
Oil	75.7	68.8	80.8	89.4	91.4	92.6	109.2
Gas	23.7	43.3	53.4	50.5	55.8	53.0	74.6
Comb. Renewables & Waste[1]	7.6	7.3	9.7	9.6	9.7	9.3	14.9
Geothermal	–	–	–	–	–	–	–
Solar	–	–	–	–	–	–	–
Electricity	18.9	36.0	41.4	42.7	43.7	46.5	53.8
Heat	0.1	0.7	0.9	0.9	0.8	0.8	1.2
Shares (%)							
Coal	*4.0*	*1.9*	*1.9*	*1.8*	*1.7*	*2.3*	*2.0*
Peat	–	–	–	–	–	–	–
Oil	*57.6*	*43.2*	*42.6*	*45.4*	*44.6*	*44.7*	*42.2*
Gas	*18.1*	*27.2*	*28.2*	*25.7*	*27.2*	*25.6*	*28.8*
Comb. Renewables & Waste	*5.8*	*4.6*	*5.1*	*4.9*	*4.7*	*4.5*	*5.8*
Geothermal	–	–	–	–	–	–	–
Solar	–	–	–	–	–	–	–
Electricity	*14.4*	*22.6*	*21.8*	*21.7*	*21.3*	*22.5*	*20.8*
Heat	*0.1*	*0.4*	*0.5*	*0.5*	*0.4*	*0.4*	*0.5*
TOTAL INDUSTRY[6]	**52.8**	**62.1**	**75.0**	**78.3**	**80.5**	**81.2**	**110.6**
Coal	4.7	3.0	3.5	3.6	3.5	4.7	5.2
Peat	–	–	–	–	–	–	–
Oil	21.3	18.1	22.1	26.0	25.6	26.3	32.7
Gas	11.9	20.2	23.4	22.7	26.1	24.0	39.3
Comb. Renewables & Waste[1]	5.7	5.7	7.7	7.6	7.2	7.5	12.3
Geothermal	–	–	–	–	–	–	–
Solar	–	–	–	–	–	–	–
Electricity	9.1	14.4	17.5	17.5	17.4	18.1	19.9
Heat	0.1	0.6	0.8	0.8	0.7	0.7	1.2
Shares (%)							
Coal	*8.9*	*4.9*	*4.6*	*4.6*	*4.4*	*5.8*	*4.7*
Peat	–	–	–	–	–	–	–
Oil	*40.4*	*29.1*	*29.5*	*33.3*	*31.8*	*32.3*	*29.5*
Gas	*22.5*	*32.6*	*31.2*	*29.0*	*32.4*	*29.6*	*35.5*
Comb. Renewables & Waste	*10.8*	*9.2*	*10.3*	*9.8*	*8.9*	*9.2*	*11.1*
Geothermal	–	–	–	–	–	–	–
Solar	–	–	–	–	–	–	–
Electricity	*17.2*	*23.2*	*23.3*	*22.4*	*21.7*	*22.3*	*18.0*
Heat	*0.2*	*1.0*	*1.1*	*1.0*	*0.9*	*0.8*	*1.1*
TRANSPORT[4]	**33.6**	**43.1**	**52.1**	**55.4**	**57.9**	**57.3**	**65.4**
TOTAL OTHER SECTORS[7]	**44.8**	**53.9**	**62.5**	**63.2**	**66.6**	**68.6**	**82.9**
Coal	0.4	0.1	0.0	0.0	0.0	0.1	0.0
Peat	–	–	–	–	–	–	–
Oil	21.1	10.7	11.8	12.6	13.0	12.7	15.4
Gas	11.9	20.2	25.3	23.8	25.6	25.9	31.5
Comb. Renewables & Waste[1]	1.9	1.6	1.8	1.9	1.9	1.9	2.6
Geothermal	–	–	–	–	–	–	–
Solar	–	–	–	–	–	–	–
Electricity	9.5	21.2	23.5	24.8	25.9	28.1	33.4
Heat	–	0.1	0.1	0.1	0.1	0.1	–
Shares (%)							
Coal	*0.9*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*
Peat	–	–	–	–	–	–	–
Oil	*47.1*	*19.9*	*18.9*	*20.0*	*19.6*	*18.5*	*18.6*
Gas	*26.4*	*37.5*	*40.4*	*37.6*	*38.4*	*37.7*	*38.0*
Comb. Renewables & Waste	*4.3*	*3.0*	*2.9*	*2.9*	*2.8*	*2.7*	*3.1*
Geothermal	–	–	–	–	–	–	–
Solar	–	–	–	–	–	–	–
Electricity	*21.3*	*39.4*	*37.6*	*39.3*	*38.9*	*40.9*	*40.3*
Heat	–	*0.1*	*0.1*	*0.2*	*0.2*	*0.1*	–

Unit: Mtoe

DEMAND

ENERGY TRANSFORMATION AND LOSSES

	1973	1990	2000	2006	2007	2008P	2020
ELECTRICITY GENERATION[8]							
INPUT (Mtoe)	**36.1**	**72.6**	**89.9**	**91.7**	**95.6**	**97.1**	**98.7**
OUTPUT (Mtoe)	**23.2**	**41.5**	**52.1**	**53.0**	**55.0**	**55.9**	**60.6**
(TWh gross)	270.1	482.0	605.6	615.9	639.7	650.1	704.7
Output Shares (%)							
Coal	*12.9*	*17.1*	*19.4*	*17.6*	*18.1*	*17.8*	*12.0*
Peat	–	–	–	–	–	–	–
Oil	*3.4*	*3.4*	*2.4*	*1.5*	*1.5*	*1.5*	*1.8*
Gas	*6.0*	*2.0*	*5.5*	*5.5*	*6.4*	*6.2*	*12.2*
Comb. Renewables & Waste	–	*0.8*	*1.4*	*1.4*	*1.3*	*1.2*	*1.3*
Nuclear	*5.6*	*15.1*	*12.0*	*15.9*	*14.6*	*14.5*	*12.6*
Hydro	*72.1*	*61.6*	*59.2*	*57.7*	*57.6*	*58.3*	*56.8*
Wind	–	–	–	*0.4*	*0.5*	*0.6*	*3.3*
Geothermal	–	–	–	–	–	–	–
Solar/Other	–	–	–	–	–	–	*0.1*
TOTAL LOSSES	**31.5**	**50.7**	**63.1**	**65.8**	**68.9**	**81.7**	**76.9**
of which:							
Electricity and Heat Generation[9]	12.8	30.4	36.9	37.8	39.8	40.5	36.9
Other Transformation	2.1	–0.9	–1.8	–5.1	–4.9	3.5	–
Own Use and Losses[10]	16.6	21.2	28.0	33.0	34.0	37.8	40.0
Statistical Differences	**–3.4**	**–1.2**	**–1.6**	**6.6**	**–4.6**	**–16.1**	**–**

INDICATORS

	1973	1990	2000	2006	2007	2008P	2020
GDP (billion 2000 USD)	–	–	–	–	–	..	..
Population (millions)	22.49	27.70	30.69	32.65	32.98	33.33	35.82
TPES/GDP[11]	..	..	..	..	..	..	..
Energy Production/TPES	1.24	1.31	1.48	1.53	1.53	1.51	1.40
Per Capita TPES[12]	7.08	7.53	8.18	8.25	8.17	8.18	9.38
Oil Supply/GDP[11]	..	..	..	..	..	..	..
TFC/GDP[11]	..	..	..	..	..	..	..
Per Capita TFC[12]	5.84	5.75	6.18	6.03	6.22	6.21	7.23
Energy-Related CO_2 Emissions (Mt CO_2)[13]	375.1	432.4	532.8	537.7	572.9	..	..
CO_2 Emissions from Bunkers (Mt CO_2)	5.2	5.6	6.4	4.2	3.6	..	..

GROWTH RATES (% per year)

	73–79	79–90	90–00	00–07	07–08	08–20	73–20
TPES	3.0	0.8	1.9	1.0	1.2	1.8	1.6
Coal	4.4	1.9	2.7	–0.7	–12.9	–0.4	1.0
Peat	–	–	–	–	–	–	–
Oil	2.4	–1.6	1.3	1.2	9.6	2.3	1.2
Gas	2.7	2.1	3.1	0.9	–2.7	2.2	2.1
Comb. Renewables & Waste	–1.6	1.4	3.5	0.0	–5.4	3.6	1.7
Nuclear	15.7	6.4	–0.2	3.6	0.5	–0.5	3.8
Hydro	3.8	1.8	1.9	0.4	2.8	0.5	1.5
Wind	–	–	–	41.4	26.2	16.2	–
Geothermal	–	–	–	–	–	–	–
Solar/Other	–	–	7.2	3.2	20.0	16.9	–
TFC	2.6	0.4	1.8	1.1	1.0	1.9	1.5
Electricity Consumption	4.7	3.4	1.4	0.8	6.4	1.2	2.2
Energy Production	1.0	2.4	3.1	1.5	–0.7	1.1	1.9
Net Oil Imports	..	..	..	..	..	..	..
GDP	–	–	–	–	..	..	..
Growth in the TPES/GDP Ratio	..	..	..	..	..	..	..
Growth in the TFC/GDP Ratio	..	..	..	..	..	..	..

Please note: Rounding may cause totals to differ from the sum of the elements.

FOOTNOTES TO ENERGY BALANCES AND KEY STATISTICAL DATA

1. Combustible renewables and waste comprises solid biomass, liquid biomass, biogas, industrial waste and municipal waste. Data are often based on partial surveys and may not be comparable between countries.

2. Other includes tide and wave.

3. In addition to coal, oil, gas and electricity, total net imports also include combustible renewables.

4. Excludes international marine bunkers and international aviation bunkers.

5. Total supply of electricity represents net trade. A negative number in the share of TPES indicates that exports are greater than imports.

6. Industry includes non-energy use.

7. Other Sectors includes residential, commercial, public services, agriculture, forestry, fishing and other non-specified sectors.

8. Inputs to electricity generation include inputs to electricity, CHP and heat plants. Output refers only to electricity generation.

9. Losses arising in the production of electricity and heat at main activity producer utilities and autoproducers. For non-fossil-fuel electricity generation, theoretical losses are shown based on plant efficiencies of approximately 33% for nuclear and 100% for hydro, wind and photovoltaic.

10. Data on "losses" for forecast years often include large statistical differences covering differences between expected supply and demand and mostly do not reflect real expectations on transformation gains and losses.

11. Toe per thousand US dollars at 2000 prices and exchange rates.

12. Toe per person.

13. "Energy-related CO_2 emissions" have been estimated using the IPCC Tier I Sectoral Approach from the *Revised 1996 IPCC Guidelines*. In accordance with the IPCC methodology, emissions from international marine and aviation bunkers are not included in national totals. Projected emissions for oil and gas are derived by calculating the ratio of emissions to energy use for 2007 and applying this factor to forecast energy supply. Future coal emissions are based on product-specific supply projections and are calculated using the IPCC/OECD emission factors and methodology.

INTERNATIONAL ENERGY AGENCY "SHARED GOALS"

The member countries* of the International Energy Agency (IEA) seek to create conditions in which the energy sectors of their economies can make the fullest possible contribution to sustainable economic development and to the well-being of their people and of the environment. In formulating energy policies, the establishment of free and open markets is a fundamental point of departure, though energy security and environmental protection need to be given particular emphasis by governments. IEA countries recognise the significance of increasing global interdependence in energy. They therefore seek to promote the effective operation of international energy markets and encourage dialogue with all participants. In order to secure their objectives, member countries therefore aim to create a policy framework consistent with the following goals:

1. **Diversity, efficiency and flexibility within the energy sector** are basic conditions for longer-term energy security: the fuels used within and across sectors and the sources of those fuels should be as diverse as practicable. Non-fossil fuels, particularly nuclear and hydro power, make a substantial contribution to the energy supply diversity of IEA countries as a group.

2. Energy systems should have **the ability to respond promptly and flexibly to energy emergencies.** In some cases this requires collective mechanisms and action: IEA countries co-operate through the Agency in responding jointly to oil supply emergencies.

3. **The environmentally sustainable provision and use of energy** are central to the achievement of these shared goals. Decision-makers should seek to minimise the adverse environmental impacts of energy activities, just as environmental decisions should take account of the energy consequences. Government interventions should respect the Polluter Pays Principle where practicable.

4. **More environmentally acceptable energy sources** need to be encouraged and developed. Clean and efficient use of fossil fuels is essential. The development of economic non-fossil sources is also a priority. A number of IEA member countries wish to retain

* Australia, Austria, Belgium, Canada, the Czech Republic, Denmark, Finland, France, Germany, Greece, Hungary, Ireland, Italy, Japan, Korea, Luxembourg, the Netherlands, New Zealand, Norway, Poland, Portugal, the Slovak Republic, Spain, Sweden, Switzerland, Turkey, the United Kingdom, the United States.

and improve the nuclear option for the future, at the highest available safety standards, because nuclear energy does not emit carbon dioxide. Renewable sources will also have an increasingly important contribution to make.

5. I**mproved energy efficiency** can promote both environmental protection and energy security in a cost-effective manner. There are significant opportunities for greater energy efficiency at all stages of the energy cycle from production to consumption. Strong efforts by governments and all energy users are needed to realise these opportunities.

6. **Continued research, development and market deployment of new and improved energy technologies** make a critical contribution to achieving the objectives outlined above. Energy technology policies should complement broader energy policies. International co-operation in the development and dissemination of energy technologies, including industry participation and co-operation with non-member countries, should be encouraged.

7. **Undistorted energy prices** enable markets to work efficiently. Energy prices should not be held artificially below the costs of supply to promote social or industrial goals. To the extent necessary and practicable, the environmental costs of energy production and use should be reflected in prices.

8. **Free and open trade** and a secure framework for investment contribute to efficient energy markets and energy security. Distortions to energy trade and investment should be avoided.

9. **Co-operation among all energy market participants** helps to improve information and understanding, and encourages the development of efficient, environmentally acceptable and flexible energy systems and markets worldwide. These are needed to help promote the investment, trade and confidence necessary to achieve global energy security and environmental objectives.

(The Shared Goals were adopted by IEA Ministers at their 4 June 1993 meeting in Paris.)

GLOSSARY AND LIST OF ABBREVIATIONS

In this report, abbreviations are substituted for a number of terms used within the International Energy Agency. While these terms generally have been written out on first mention and abbreviated subsequently, this glossary provides a quick and central reference for many of the abbreviations used.

bcm	billion cubic metres
b/d	barrels per day
CCS	carbon dioxide capture and storage
CDM	clean development mechanism (under the Kyoto Protocol)
CHP	combined heat and power
cm	cubic metre
CO_2	carbon dioxide
ERU	emissions reduction unit
EU	European Union
GDP	gross domestic product
G8	Group of Eight (Canada, France, Germany, Italy, Japan, Russia, the United Kingdom and the United states)
GHG	greenhouse gas
GW	gigawatt, or 1 watt by 10^9
HFC	hydrofluorocarbon
IEA	International Energy Agency
JI	joint implementation (under the Kyoto Protocol)
kWh	kilowatt-hour , or 1 watt x 1 hour x 10^3
LNG	liquefied natural gas

m^2	square metre
mb	million barrels
mcm	million cubic metres
Mt	million tonnes
Mt CO_2-eq	million tonnes of CO_2-equivalent
Mtce	million tonnes of coal equivalent
Mtoe	million tonnes of oil equivalent, see toe
MW	megawatt, or 1 watt x 10^6
MWh	megawatt-hour, or 1 watt x 1 hour x 10^6
NGL	natural gas liquids
NO_2	nitrogen dioxide
NO_x	nitrous oxides
OECD	Organisation for Economic Co-operation and Development
PFCs	perfluorocarbons
PV	photovoltaic
R&D	research and development
RES	renewable energy sources
t	tonne
tcm	trillion cubic metres
TFC	total final consumption of energy
toe	tonne of oil equivalent, defined as 10^7 kcal
TPES	total primary energy supply
TSO	transmission system operator
UNFCCC	United Nations Framework Convention on Climate Change
VOC	volatile organic compound

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