National Energy Board
Office national de l'énergie

Canada's Energy Future

SPEAKER SERIES SUMMARY

STAKEHOLDER INPUT 2006

Canada

ENERGY FUTURES PROJECT
SUMMARY OF SPEAKER SERIES
AUGUST 2006

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INTRODUCTION

The Board has embarked on its next *Energy Futures* Report, which is scheduled to be released in the fall of 2007. The last report, entitled, *Canada's Energy Future: Scenarios for Supply and Demand to 2025* was released in 2003. The objective of the report is to provide a long-term energy supply and demand outlook for Canada. The report provides an opportunity to integrate the short term market intelligence reflected in the various commodity-specific Energy Market Assessments (EMAs) into an "all energy" market analysis and outlook.

A key component of developing the *Energy Futures* Report is to undertake an extensive consultation process with various stakeholders in the energy industry. Experts are invited to share their views and insights on current and future market trends. The information gathered helps to develop comprehensive and realistic long-term outlooks. This time around, the Board is documenting and sharing the input we received with the public, as this information is valuable in helping to understand energy market dynamics. To this end, we developed the *Energy Futures Speaker Series.*

In the *Energy Futures Speaker Series*, nineteen experts were asked to provide a presentation to the Board on key areas of interest. These presentations occurred over a seventeen week period from March to June 2006. In addition, many of these experts were asked to comment on the scenarios currently being developed by the Board for the 2007 *Energy Futures* Report. Below you will find a copy of each of the presentations as well as a summary of the key messages that were prepared by NEB staff members. The report is categorized according to energy topic: Natural Gas, Oil and Natural Gas Liquids, Coal and Electricity, and the Future of Energy Markets. A separate document concerning "Consumer Response to High Energy Prices", also part of the *Energy Futures Speaker Series*, is available. Within each of these sections, a summary of each speaker's presentation is provided, including an introduction to the subject matter, key highlights and conclusions. Following the summary sections are speaker biographies and original presentations for further reference. It is our hope that the information contained in this report will help make the development of the *Energy Futures* Report more transparent, while better sharing the information obtained.

KEY MESSAGES

The *Energy Futures Speaker Series* presentations illuminate several key messages about our energy future, which will assist the National Energy Board in its development of the next *Energy Futures Report*.

The overarching message gathered from the *Energy Futures Speaker Series* is that energy supply and demand markets are presently at a crossroad. Rapid global energy demand growth and constrained conventional energy supplies have led to higher energy prices than we have experienced in the recent past. This is further exasperated by heightened international and national awareness of sustainability issues.

On the natural gas side, we know natural gas supply is expected to trail future increases in demand, and so liquefied natural gas (LNG) imports will be a key factor in future energy markets. LNG market prices will need to be adequate enough to attract LNG to North America, while not becoming overly expensive, which may destroy incremental gas demand. LNG is not expected to drive North American gas prices down, as host countries are seeking higher economic rents and LNG scale efficiencies have largely been captured at this point. Future LNG costs will reflect rising costs of labour and materials. Given the timeframe to be studied in the *Energy Futures* analysis, gas hydrates are not likely to be a source of energy which we will consider; however, hydrates may act as a second "tier" of supply for the northern pipelines. Compressed natural gas (CNG) may evolve into a viable transportation option for stranded natural gas offshore Newfoundland, with possible development by 2014. However, importation of LNG in more significant volumes could rule out the development of this supply source.

The *Energy Futures Speakers Series* included discussion on the possible challenges posed by the booming oil sands development. The industry will continue to experience rapid investment and is projected to grow to 3.2 million barrels per day (b/d) by 2020. However, the oil industry will face major challenges in the development of oil sands, including capital costs, infrastructure constraints, socio-economic impacts, environmental impacts of development and labour availability. Anxiety remains that oil sands development is not being appropriately managed, with constraints on production such as greenhouse gas emissions and water usage. Consequently, there is increasing opposition to letting the oil sands industry proceed with a "business as usual" mentality. The prospect of building an integrated bitumen upgrading, refining and petrochemical production plant is being discussed in Alberta, focusing on opportunities for moving up the energy value-added chain with industry. While CO_2 use in enhanced oil recovery (EOR) may be a viable possibility in Canada, such an initiative would likely require government support. EOR is not sufficiently economic by itself to support large scale infrastructure development.

On the coal and electricity generation end, Integrated Gasification Combined Cycle (IGCC) appears promising in the longer run, but there exist interim challenges such as gasification with sub-bituminous and lignite coals, in addition to the reliability of gasification plants and commissioning risks. The driver for CO_2 storage, manufacture of hydrogen by gasification and clean coal will be Canada's emissions target, which will largely determine the speed at which these technologies develop. Finally, added value from CO_2 storage would stem from EOR and repressurization of oil sands gas caps and enhanced coal bed methane recovery. Within 15 to 20 years, clean coal electricity generation will provide a means to stabilize global concentrations of carbon dioxide.

The future energy environment requires a cleaner energy system, which will hinge on changes to our current lifestyles. In order to effect change, several solutions will need to come into play, including influencing consumer choice, introducing the right policies and implementing effective decision making. Our energy future sees a strong role for sustainable fossil fuels. Society will continue to be "addicted" to oil, but this dependency can be minimized through modest changes to our lifestyle. Additionally, the future energy picture points to the need for sustainability and efforts on this front will require multi-disciplinary actions. There are a number of technologies and approaches that can be adopted to help us achieve a more sustainable energy environment, which will require a coordinated effort and a commitment to change. Nonetheless, we should be optimistic about the future of the energy system.

SPEAKER SUMMARIES

NATURAL GAS

1-Natural Gas and LNG Outlook by Christopher Theal (Managing Director, Institutional Research, Tristone Capital) - 8 March 2006

Introduction

With North American natural gas supply expected to trail future increases in demand, imports of liquefied natural gas (LNG) from offshore sources are viewed as the largest source of incremental natural gas supply available to the continent. Large amounts of natural gas have been discovered in locations around the world, but are too remote to have pipeline access to markets. In such cases, the gas can be chilled to roughly -260 F, thereby reducing its volume about 600 times, and making it practical to transport by ship. Over 40 import terminal projects have been proposed for North America and development of significant LNG trade could have implications for North American natural gas supply, demand and prices.

Key Highlights

As early as 2009, LNG imports could be as important to the U.S. as Canadian gas imports are now. Imports could reach 10 billion cubic feet per day (Bcf/d); however, there could be key risks to substantially increasing LNG imports. Such risks include security issues, local opposition to development of import terminals, project timing, fiscal terms with national oil companies, financing supply projects in less stable regions and labour risks. The greatest labour risk is training enough qualified ship captains.

Despite higher import volumes, LNG is not expected to drive North American gas prices down because host countries are seeking higher economic rents and LNG scale efficiencies have largely been captured at this point. From now on, LNG costs will reflect rising costs of labour and materials. North American domestic gas prices are likely to remain at approximately US$7 million cubic feet (Mcf) to cover the increasing cost of developing North American gas resources and to attract sufficient LNG from markets in Europe and Asia.

Finally, LNG is cost-competitive with northern gas projects because supply costs plus delivery costs are approximately equal and major oil companies will allocate capital wherever the execution risk is lower.

Conclusions

LNG imports will be a key factor for consideration in the Board's *Energy Futures* analysis. Market prices in the *Energy Futures* scenarios must be sufficient to attract LNG spot cargoes to North America, but not so high as to destroy the incremental gas demand that would have been served by LNG.

***2-Gas Hydrates by Kirk Osadetz, (Research Geo-scientist, Geological Survey of Canada)* - 6 April 2006**

Introduction

Gas hydrates are a unique trapping mechanism for natural gas located broadly in the north of Canada and offshore of both coasts of Canada, as well as in similar environments around the world. These potentially could dwarf the supplies coming from other conventional and unconventional sources of gas if successfully developed. There is world-wide interest, especially from countries that are short of their own domestic energy supplies (such as Japan, Korea and India). Each of these countries is supplying money for research in Canada where hydrates can be accessed relatively cheaply, such as the Mallik deposits in the Mackenzie Delta.

Key Highlights

Gas hydrates are a form of natural gas contained within a clathrate (cage-like) molecular structure of ice. It is stable within a range of temperature and pressure conditions. Hydrates are a very efficient means of storing methane, with one unit of hydrate containing 160 units of methane. The energy efficiency is equivalent to bitumen content. Because of this efficiency, synthetic hydrates could be used for purifying water in oil sands plants. In permafrost regions, it may or may not be associated with underlying free gas. In ocean bottom conditions, it is associated with the water-sediment interface, either diffusely within the underlying sediments, or as a solid mass on the surface of the ocean-bottom and is generally of biogenic origin.

Current research activity in this area is driven by the need for additional gas supplies, since gas is considered to be a cleaner fuel source than coal or oil. Research dollars come from Japanese, Korean and Indian companies and governments. As there are currently no proven methods for recovering the methane from hydrate deposits, most of the current research is focused in this area. Hydrates are self-preserving in that the first water to be released wraps around the hydrate in order to protect them from further disassociation. One transportation method being considered utilizes this self-preservation characteristic: pelletized gas hydrates could be transported as a solid instead of as a gas. Korea is considering the physical mining of diffuse gas hydrates on the sea-floor which would be barged to the onshore gas plant.

World-wide resources estimates are very large and, for Canada, equally large in comparison with other forms of gas. Canada is estimated to have 1,500 to 28,000 trillion cubic feet (Tcf) of gas in place contained in hydrates, with 311 Tcf in the Beaufort/Mackenzie Delta region. Both the Pacific and Atlantic margins have confirmed gas hydrates deposits. The Pacific deposits consist of both the diffuse sediment type and the solid sea-floor mass type. These were sampled accidentally by fishing draggers and also by International Ocean Drilling Program drilling programs in 2002 and 2005. The Atlantic deposits are the diffuse sediment types and were encountered during conventional drilling operations. To date, the primary means of locating the deposits is by seismic, which reveals a mimicking Bottom Simulating Reflection.

The Mallik location was chosen for its prime conditions: the location has a thick hydrate level with a high concentration of gas hydrates in the sediments; overlies a conventional free gas zone; provides access to extensive geological knowledge from conventional drilling; and, the location is accessible. Work is funded and conducted by an international consortium involving at least six countries. Last field activity occurred in 2002 and consisted of a three-well program with a central testing well and two observation wells surrounding the central well. Tests were conducted using pressure reduction, thermal injection and inhibitor injection. All test types resulted in some gas production which was flared. Case studies and development plan schemes are being developed and shared with consortium members.

Conclusions

If there was a transportation system available and based on current knowledge, hydrates would be economic at gas prices of $10 million cubic feet (Mcf). However, these costs are not competitive with conventional gas at this time. Costs are currently much higher than conventional gas costs, but it is expected that hydrates could make up a second tier of supply for the Mackenzie Valley Pipeline. Additional testing and modeling is required to ensure results. Plans are to have a full scale production test in about five years and first production by 2020.

3-Compressed Natural Gas by Michael Hanrahan (Managing Director, Centre for Marine CNG Inc.) - 25 April 2006

Introduction

Compressed natural gas (CNG) is a method to increase the efficiency of storing a large volume of gas for shipment by a tanker for short distances. It is less efficient than liquefied natural gas (LNG), but can be accomplished at a lower cost, with the key to overall economics being the distance to market. It is a way to potentially access smaller gas deposits, which would not be practical for LNG or pipeline access, and would allow those currently stranded gas supplies to be utilized.

Key Highlights

Compressed natural gas is natural gas that has been compressed under high pressures and low temperatures to enable storage of a large quantity of gas in a small space. Under these conditions, CNG volumes can be reduced to about 1/200 of the volume it occupies at atmospheric pressure and temperature. This compares to the 1/600 reduction for LNG.

CNG potentially provides a niche opportunity for small volumes of natural gas resources that are within 300 nautical miles (nm) to 2,000 nm of a market. The operating pressures range from 1,500 to 4,000 pound-force per square inch (psi) and temperatures from -30 C to ˚45 ˚C. Development of CNG has lower capital costs compared to LNG, but higher risks associated with it. Gas-to-liquids has the same niche market (300 to 2,000 nm range) but requires a larger resource base, so capital requirements are larger. Total costs for all components are cheaper than for LNG. The cost of the steel required for constructing thick tank walls is the most expensive component of transportation costs.

Potential resides primarily in Eastern Canada as a possible way to access offshore gas supplies from relatively small discovered reservoirs. The current discoveries offshore Newfoundland, in the Jeanne d'Arc Sub-basin, contain gas resources of about 4 trillion cubic feet (Tcf) (White Rose 2.7 Tcf and Hibernia/Terra Nova 1.3 Tcf), more than the reserves at Sable Island. In addition, this area is located within the optimum supply distances to Boston and New York. Longer term, gas discoveries offshore Labrador could also be developed in spite of the more extreme operating conditions. Offshore Labrador would require a longer lead time for development (about 10 to 20 years).

There have not been any discoveries in the Laurentian Basin and offshore B.C. to date. If discoveries were made in the future, CNG would be a possible means of transporting gas to markets. Stranded gas in the north of Canada is unlikely to be developed using CNG as it is too far from markets and there are too many ice issues to deal with be dealt with. Risk for CNG in an ice-bound situation is much higher than for LNG; that is, safety is a big issue.

There are seven main players in the running for ship design and all designs are scalable from barge size to full tanker size. Gas could be stored in tanks, horizontal pipes or coselles (spiral wound tubing). Essentially, each of these is in some stage of testing or design, and until that testing is completed, the most efficient storage system remains to be determined.

Centre for Marine CNG Inc. is considering four CNG carriers with a capacity of 1.2 billion cubic feet (Bcf) per ship. Canadian players include TransCanada and Emera, and both companies are partners with the Centre for Marine CNG Inc.

Newfoundland is not a large enough gas market to support this development and the most likely market will be the U.S. New England states (1,200 nm to New York City). It is possible to ship to Goldsboro in Nova Scotia and unload CNG into the M&NE Pipeline for delivery to Boston. However, that pipeline may not be available if the Keltic LNG terminal goes ahead. Additionally, transporting gas to the market by ship would also avoid pipeline tolls.

Centre for Marine CNG Inc. has conducted economic feasibility studies under two potential cases. The common parameters were: field production rate of 250 million cubic feet per day (MMcf/d); a distance of 750 nm; and an unloading rate of 500 MMcf/d. Delivery costs would be US$1 to US$2.50/million British thermal units (MMBtu), with US$0.50 to US$1/MMBtu for production costs for the gas. In Case 1 (CNG single project), CNG would be economic, while LNG or a pipeline would not. In Case 2 (Basin-wide Case), 600 to 700 MMcf/d total production could justify a sub-sea pipeline to Nova Scotia and/or New Brunswick and CNG would not be viable. However, a pipeline would require processing of the natural gas liquids either before the gas leaves Newfoundland or after it arrives in Nova Scotia. The Newfoundland provincial government is strongly opposed to shipping raw gas out of the province. There is very little political risk associated with development of these resources as compared with development of resources for LNG elsewhere in the world.

Conclusions

Compressed natural gas seems to be a viable transportation option for stranded natural gas offshore Newfoundland, with possible development to occur by 2014 or later. It is more unlikely that CNG could be used to develop offshore Labrador resources due to the increased transportation distances. Development still has a number of hurdles to overcome, including safety issues for the delivery to Boston or New York harbours. Importation of LNG in more significant volumes could preclude the development of this supply source.

OIL AND NATURAL GAS LIQUIDS

1-Oil Sands and Canada's Energy Future by Dan Woynillowicz (Senior Policy Analyst, Pembina Institute) - 2 May 2006

Introduction

Dan Woynillowicz of the Pembina Institute was invited to provide his insights on environmental concerns and considerations associated with oil sands development in the long term. His discussion also focused on the Pembina Institute's work on the Alberta Genuine Progress Indicator (GPI), a framework for measuring total well-being, which tracks 51 social, environmental and economic indicators over a 40-year (plus) period.

In the last 15 years, the oil sands have evolved from being considered a vast but inaccessible resource to becoming globally recognized as an abundant, secure and affordable source of crude oil. In 2005, oil sands production was 1.1 million barrels per day and is projected to grow to around 3 million barrels per day by 2015. Canada's oil sands represent a new frontier of oil production at a time of growing uncertainty around the global supply of oil and growing demand from the United States and Asia.

Key Highlights

The story of the vast economic potential of oil sands development is already very well-known, but there are fewer sources to provide information about the environmental consequences.

The development of the oil sands, characterized by high demand for energy, intensity of environmental impacts in the boreal forest and significant contribution to greenhouse gas emissions, is an unprecedented challenge. The oil sands are emerging as a focal point of discussion about the future of energy production and consumption.

Potential negative impacts of development include both socio-economic and environmental issues. A growth rate that is too fast-paced potentially results in impediments to quality of life, increased costs for labour and materials, and reaching environmental threshold limits. There is already lagging physical and social infrastructure problems in the Regional Municipality of Wood Buffalo (such as lack of housing) and difficulties in attracting and retaining trade and professional labour.

The large revenues associated with oil sands will drive development, but will also create public expectations that companies can "afford to pay" and can be reasonably expected to use a portion of profits to protect the environment. Higher prices will further support this view. According to a 2005 government poll, Albertans believe that the environment should be given higher priority. There will be increased pressure on government to effectively manage oil sands development. Proper management is also necessary to minimize the impacts on social well-being. There is growing recognition and concern over the potential problems that could arise without cautionary development. The international recognition of the oil sands means that Canada's management of development will be globally critiqued.

Mr. Woynillowicz also commented on the price scenarios proposed by the NEB.

The low price case ($35 West Texas Intermediate (WTI) and $5 Henry Hub (HH)) could lead to relaxed environmental restrictions to spur development and little incentive for innovation and improved environmental performance.

The mid price case ($50 WTI and $7 HH) could lead to high public expectations that the industry has the “ability to pay”. This case would require that the definition of “business as usual” change, or there will be increased public opposition to the pace of growth.

The high price case ($75 WTI and $15 HH) will trigger high public expectations that the industry has the ability to pay and could create greater opportunity for innovation, seen in stepwise improvements to produce more, with less damage to the environment.

Conclusions

There is call to slow the pace of oil sands development in order to allow for better understanding and assessment of the risks to the environment. This could mean temporarily halting further approvals of projects. Pembina’s view is that the pace of development is not being managed now and there is increasing opposition to letting the industry proceed with a “business as usual” mentality. Although the environment and labour issues will place limits on the pace of growth such that not all planned projects will proceed, there is a role to be played by the provinces to place stricter targets on industry for better environmental management. Areas of note include greenhouse gas emissions and water use.

2-Oil Sands Industry Outlook by Bob Dunbar (President, Strategy West Inc.) 5 May 2006

Introduction

Oil supply derived from oil sands bitumen is projected to exceed 3 million barrels per day in the 2015-2020 timeframe, accounting for nearly 75 per cent of total Canadian oil production. Oil sands will therefore play a vital role in Canada's energy future and an examination of the issues and potential concerning oil sands supply are critically important.

Key Highlights

After all announced projects have been adjusted for project timing and probability of completion, oil sands Synthetic Crude Oil (SCO) and non-upgraded bitumen supply is projected to reach 3.2 million barrels per day by 2020. Of this supply, about two-thirds are projected to be SCO. Required capital expenditure (CAPEX), strategic capital only, for the adjusted case averages $7.2 billion per year.

Major challenges facing the industry include:
- energy use, sources and costs;
- socio-economic impacts;
- infrastructure constraints;
- labour availability and productivity; and
- environmental issues including air emissions, water use, land disturbance and reclamation and cumulative effects.

In the future, energy intensity will likely be reduced through further efficiency improvements and application of new technologies, such as bitumen gasification and bitumen combustion, with some potential for nuclear.

Mr. Dunbar predicted that potential new technology applications could include:
- the use of hybrid steam/solvent recovery for in situ projects;
- commercial application of Vapour Extraction (VAPEX) and Toe-to-Heel Air injection (THAI) recovery methods;
- improved and new tailings technologies for mining operations; and
- a myriad of new upgrading process configurations.

The following table illustrates how bitumen supply might play out in the Fortified Islands and TREEES scenarios:

	Fortified Islands	TREEES
Bitumen Production	Greater	Less
Upgrading Intensity	No Significant Change	No Significant Change
Energy Intensity	Greater	Less
Emissions Intensity	Greater	Less

Conclusions

The industry will face major challenges in the development of oil sands. Environmental impacts of development, labour availability, capital costs, infrastructure constraints, socio-economic impacts and energy use, sources and costs will each play a major role.

3-Beyond Primary and Secondary Recovery-Business Case for Conventional EOR by Blaine Hawkins (Manager) and Ashok Singhal (Senior Staff Research Engineer), (Alberta Research Council-Conventional Oil & Natural Gas Business Unit)

30 May 2006

Introduction

In many oil-producing regions of the world, conventional oil production levels have peaked and primary production methods have been followed by enhanced oil recovery methods. The most common of these methods has been secondary recovery by waterflooding and tertiary recovery by hydrocarbon miscible flooding. Current recovery estimates indicate that about 15 per cent of oil-in-place will be recovered by primary means and an additional 15 per cent by secondary means. However, it is also estimated that a greater focus on enhanced oil production from conventional oil sources could potentially raise total recovery to 45 per cent of oil-in-place. This represents a sizable amount - up to 30 million barrels per day worldwide.

Conventional oil production in the Western Canada Sedimentary Basin (WCSB) peaked in 1973. Although soon to be surpassed by oil sands production, conventional crude oil in the WCSB still accounts for a significant portion of oil supply. While most hydrocarbon miscible projects in the WCSB have been completed, waterflooding and CO_2 flooding are foreseen to play a prominent role in enhanced oil recovery (EOR).

Key Highlights

The number of EOR projects in Canada totals 45, with 15 related to thermal projects and 30 to gas/solvent injection projects. EOR related to oil production is 13.0 per cent in Canada, 13.8 per cent in the U.S. and 3.2 per cent worldwide.

Enhanced oil recovery methods include waterflooding, hydrocarbon miscible and CO_2 miscible flooding. In Alberta, waterflooding increases the average recovery factor (primary plus secondary) to 28 per cent for light/medium gravity oil pools, and to 31 per cent for heavy gravity oil pools. High water to oil ratios (about 10 to one) are raising public concern about water use and water handling costs are increasing.

Hydrocarbon miscible flooding raises recovery factor for light and medium pools by an incremental 12 per cent, to a total of 57 per cent (primary, secondary and tertiary). In 2004, there were 29 active projects in Alberta and B.C. There have been no new projects since the early 1990s due primarily to the expense of injection fluids.

CO_2 miscible flooding is well established in the U.S. with 82 projects, based on the large natural source of CO_2 close to injection targets, and low cost production and compression. In Canada, CO_2 flooding has promise, but is constrained by higher costs for CO_2 capture (major sources are man-made), with considerable infrastructure required for delivery to targets and by higher compression costs.

The Innovative Energy Technologies Program (IETP) is a $200 million commitment by Alberta Energy to support innovative technologies and pilot/demonstration projects, and to encourage responsible development of oil, natural gas and in situ oil sands projects. To date, $15 million has been provided to support CO_2 EOR projects, and $11 million for polymer flood projects.

Two major initiatives are underway concerning EOR. The first of these involves improved waterflooding including:

- polymer flooding and use of alkalines and surfactants;
- combination of polymer technology with horizontal wells;
- chemical additives for reducing water usage and improving recovery; and
- injection of waste/stranded gas in water-after-gas (WAG) mode to improve sweep.

The second initiative involves four approved CO_2 EOR projects across Alberta.

Major issues regarding EOR implementation include WAG and CO_2. Regarding WAG, concerns include adequate gas supply, adequate facilities, number of wells, corrosion, incremental capital and operating costs.

Concerning $CO_{2,}$ it is essential to note that the supply is remote from targets, infrastructure is ageing and many target pools require repressurization. Enhanced oil recovery alone is not economic enough to support large-scale infrastructure development.

An assessment of a Medicine River example suggested reasonable economics with a rate of return of 15 to 30 per cent based on discounted cash flow analysis, long payout periods (5 to 12 years discounted at 10 per cent), and sensitivity to capital and operating costs, including CO_2 supply cost and volumes. Infill drilling had little effect on net present value or payout period.

Conclusions

The potential for EOR is very good. There is a window of opportunity in the order of five to six years for CO_2 EOR implementation, which is based on the condition of ageing infrastructure.

4-Integrated Bitumen Upgrading Complex in Alberta by John McGinnis (Director of Hydrocarbon Upgrading, Alberta Government Department of Economic Development) 21 June 2006

Introduction

The high level of activity in the oil sands has raised concern about the large number of proposed projects over the next 10 to 15 years, as increased production of bitumen and synthetic crude oil could exceed current refinery capacity resulting in the value of these products declining over time. Increasing Alberta's finished product capacity (including lower-cost bitumen-derived petrochemical products) could mitigate this potential problem. Consequently, the Government of Alberta, in collaboration with industry partners, has undertaken a number of technical and marketing studies to assess value-added upgrading of bitumen to finished products.

This presentation covered the results of a study for an integrated plant concept, combining bitumen upgrading, refining and petrochemical production. The study is part of ongoing efforts by the joint Industry – Alberta Government Hydrocarbon Upgrading Task Force (HUTF) to achieve more processing of bitumen to finished products within the province. David Netzer, Consulting Chemical Engineer, and associates of Houston, performed the study, with a due diligence review of the results by Colt Engineering of Calgary.

Key Highlights

The establishment of the HUTF was triggered by the province's evolving petrochemical sector ethane feedstock shortfall. Growing concern has intensified the search to find alternative ethane supply, perhaps from oil sands by-products. At the same time, there is a growing concern that North American refinery capacity may not be able to keep up with increasing bitumen product supply. Potential bitumen over-supply could lead to product discounting, causing the light to heavy oil differential to widen further. By 2010, oil sands production is expected to reach 50 per cent of Canadian crude oil output.

The U.S. has not built any new refinery capacity for years; however, U.S. petroleum product demand is growing at a rate of about three per cent per annum. Although increasing facility capital costs are a world-wide phenomenon, there is a window of opportunity for a competitive green-field complex to be constructed in Alberta to produce products for export.

Government and industry have initiated jointly-funded studies to develop a business case for upgrading bitumen to high-value end products. The Netzer "concept" study determined several benefits, including significant savings in capital and operating costs due to synergies among several process steps, improved economics based on conversion of low-cost bitumen to higher value products and significant environmental advantages and reduced footprint over non-integrated facilities.

The estimated cost of the 300 million barrels per day (Mb/d) undiluted bitumen world-scale complex is about C$11 billion, with the main products being fuel (high quality-low sulphur diesel meeting California market specifications, kerosene and gasoline); petrochemical products (ethylene 1,000 kilo tonne per year (KT/y) world-scale volume, propylene, butadiene and benzene); and, synthesis gas for ammonia production.

The estimated internal rate of return (IRR) on the reference case is 19.5 per cent (WTI US$40/barrel (bbl) 2006 through 2012; +$10 or -$10/bbl resulting in 23 per cent IRR and 15.6 per cent IRR, respectively). The reference case output results in about 62 per cent of the bitumen feed being converted to fuel products, particularly diesel. The cost estimates include cost escalation factors to adjust for cost increases over the estimated seven-year construction timeline.

The location of the complex would be in the Alberta industrial heartland, extending from refinery row in eastern Edmonton to the Fort Saskatchewan and Red Water areas. In fact, the HUTF is encouraging upgrader projects to locate in this area rather than the over-heated Fort McMurray region. The study cost estimates incorporate adjustments to account for the somewhat “hot” Edmonton market location.

Both diesel and gasoline output would require construction of an export product pipeline, as the domestic petroleum products market is essentially balanced. According to Mr. McGinnis, an export line to Chicago, Illinois, using existing oil pipeline rights-of-way, would be the most likely option. The biggest hurdles for the product export pipeline would be executing long-term supply/sales contracts to underpin the facilities, as well as the current labour and material constraints.

A complex concept shifting toward increased gasoline production, as opposed to diesel, would require an additional C$2.2 billion in investment. The market would choose the product slate.

Conclusions

The conceptual study represents only one possible configuration for a potential integrated plant located in the greater Edmonton, Alberta area. It is intended (using current technology) to provide one idea of an economically-feasible integrated complex, complete with volume, cost and revenue return estimates to allow interested parties a starting point for discussions. It is hoped that discussions could potentially lead to some form of integrated hub development in the Edmonton area.

The study provides a concept design. Companies would have to provide their own complete engineering designs and cost estimates. However, the Alberta Government would be prepared to consider a variety of incentives if industry is unable to proceed on its own. For example, an incentive system that would facilitate a collaborative approach and at the same time provide an opportunity for provincial revenue and credit balance would be considered.

COAL AND ELECTRICITY

1-Coal and Technology Systems for Concentrated CO_2 Delivery by Allen Wright (Executive Director, The Coal Association of Canada), Bob Stobbs (Executive Director, Canadian Clean Power Coalition) and Bill Gunter (Principal Scientist, Alberta Research Council)
12 June 2006

Introduction

Roughly 19 per cent of Canada's electricity generation is coal-fired. Coal generation became unpopular during the 1980s and 1990s because of its carbon emissions. Until a few years ago, there were essentially two ways to address the challenge of greenhouse gas management: to produce and use energy more efficiently or, to rely increasingly on low-carbon and carbon-free fuels. Unfortunately, energy efficiency and the use of alternative energy may not be enough to stabilize global concentrations of carbon dioxide. Carbon sequestration offers a third option that could, in tandem with the continued development of clean coal generation technologies, prove affordable, effective and environmentally safe.

Key Highlights

Canadian metallurgical coal is experiencing a renaissance in Alberta and British Columbia, and opportunities for Canadian metallurgical coal are driven by demand in China, India and Brazil.

Canadian steam coal production remains consistent with some export growth. Steam coal consumption is at risk in Ontario with projected plant shutdowns. Steam coal production remains strong in Alberta, Saskatchewan, New Brunswick and Nova Scotia.

Canadian Clean Power Coalition goals are to build and operate a full-scale clean coal demonstration plant by 2012 that will provide flexible fuel capability (different types of coal and petroleum coke) at a competitive cost of power.

Three types of clean coal technologies are being examined including flue gas amine scrubbing, CO_2/O_2 combustion, and coal gasification (Integrated Gasification Combined Cycle (IGCC) with CO_2 capture).

Mr. Stobbs pointed out that IGCC is facing specific challenges. The main challenges of IGCC are its reliance on bituminous, sub-bituminous and lignite coals for gasification, the reliability of gasification plants and the commissioning risk. Integrated Gasification Combined Cycle co-production of power, hydrogen, heat and syngas (polygeneration) is attractive commercially in Western Canada.

Production of clean power with CO_2 is technically feasible and can become economic at certain locations, however, gasification costs and reliability depend on feed quality and there is little experience with low rank western Canadian lignite, sub-bituminous coals and coal-coke mixtures.

Mr. Stobbs also commented on the scenarios National Energy Board staff has developed. In the TREEES scenario, clean coal technologies would become the standard for coal-fired plants. In the Fortified Islands scenario, slower growth would result in existing plants being kept in service longer, and would cause slow deployment of clean coal technologies. In Continuing Trends, strong economic growth will increase the need for new plants while global market forces will encourage adoption of clean coal technologies.

Canada's emissions target is the future driver for CO_2 storage, manufacture of hydrogen by gasification and clean coal. Added value from CO_2 storage would come from Enhanced Oil Recovery (EOR), repressurization of oil sands gas caps and enhanced coal bed methane (CBM) recovery.

Gasification in oil sands upgrading produces inexpensive fuel and hydrogen. This fuel and hydrogen can use a range of feed materials, replace natural gas (used in production of synthetic crude oil) and produce a higher grade CO_2 waste stream.

Currently, there are four CO_2 supply hubs in Alberta: Fort McMurray, Fort Saskatchewan, Red Deer/Joffre and Wabamun, which is west of the city of Edmonton. In the future, there could be a CO_2 pipeline from Fort McMurray to Edmonton, then to the east of Calgary to end at the Empress hub on the Montana border. There could be lateral pipelines as well.

On the environmental side, the consequences from the exploitation of fossil fuels in Canada are at the heart of strategic development. The three strategies to address climate change are energy efficiency, fuel switching and carbon management.

Conclusions

Clean coal electricity generation, namely integrated gasification combined-cycle technology together with carbon sequestration, will be a means to stabilize global concentrations of carbon dioxide starting in 15 to 20 years.

The major challenges of gasification technology include incompatibility with low-rank sub-bituminous and lignite coals, high commissioning risk and uncertain plant reliability. The Canadian Clean Power Coalition is addressing these challenges by developing a full-scale clean coal demonstration project. There is great potential for gasification and CO_2 storage, particularly related to oil sands upgrading operations, enhanced oil and gas and coalbed methane recovery. The speed at which the technology develops will largely depend on Canada's emissions target.

THE FUTURE OF ENERGY MARKETS

1--Sustainable Fossil Fuels: The Unusual Suspect in the Quest for Clean and Enduring Energy by Dr. Mark Jaccard (Simon Fraser University)
13 April 2006

Introduction

The Board invited Dr. Mark Jaccard of Simon Fraser University to speak about his most recent book entitled, *Sustainable Fossil Fuels: The Unusual Suspect in the Quest for Clean and Enduring Energy.* The subject matter provides another view on the numerous uncertainties surrounding our future energy system.

Key Highlights

Much of the discussion surrounding fossil fuel use focuses on the availability of supply in the future and the environmental impacts. The traditional solutions proposed for these problems include halting the use of fossil fuels and moving towards renewable energy, nuclear energy and energy efficiency improvements (the 'usual suspects'). There is no doubt that each of these proposed solutions has the potential to significantly impact the future energy system. However, these solutions also pose their own set of challenges, which should also be considered. It is important to compare and contrast strengths and weaknesses of all energy sources when making decisions for the future.

Nuclear energy has to contend with risk aversion. Human beings tend to put a significant amount of weight on extreme events, such as a nuclear accident. This risk aversion could make it difficult for local authorities to site nuclear power plants and therefore for nuclear to replace fossil fuels.

Renewable energy advocates have argued that renewable technologies will benefit from economies of scale and economies of learning. As we start to mass produce and apply these types of technologies, their costs will decline and become more competitive with conventional energy sources. However, as we scale-up renewables to use more of them, there could be countervailing factors to cost declines such as low energy density, intermittency of supply and inconvenient location of resources.

Some energy efficiency improvements already occur and this is demonstrated by the fall in energy intensity over time (i.e., energy use per unit of gross domestic product). However, acceleration of this trend has proven to be very difficult. There are a number of barriers to the more rapid adoption of energy efficiency improvements. Additionally, there is a higher risk associated with adopting energy efficient technologies than adopting conventional technologies. Energy efficient technologies tend to have a higher up-front capital cost than conventional technologies; if something happens to the technology before the additional cost is made up through energy savings, then the investment is lost (e.g., breaking a high efficiency light bulb). Improved energy efficiency technologies also tend to be newer technologies, and therefore more risky due to higher failure rates compared to their conventional counterparts.

Energy efficient technologies might not provide the same level of service as more conventional services and despite having attractive economics and being more environmentally-friendly, they are not adopted. For example, the early compact florescent light bulb provided a less desirable quality or hue of light than conventional light bulbs and so was not as readily adopted. Similarly, public transit does not provide the same level of convenience and privacy as driving a personal vehicle.

Government policy may help in overcoming some of these barriers to energy efficiency improvements. However, the policy instruments that we have chosen to employ, such as information programs and subsidies, have proven to be ineffective, and there are political barriers to using other policy instruments, such as regulations and energy prices.

Dr. Jaccard compares the total costs and potential difficulties of scaling up the ‘usual suspects’ (nuclear, renewable, and energy efficiency improvements) with the scaling up of the ‘unusual suspect’ (fossil fuels in combination with technologies and processes to reduce environmental impacts, such as CO_2 capture and storage) and finds that there is an important role for fossil fuels in a sustainable future.

To achieve this sustainable future, policies need to be developed that assign a cost to emissions. Dr. Jaccard suggests developing both supply and demand side policies, such as a carbon management standard (removal of carbon from the ground comes at the cost of being responsible for replacing it), a greenhouse gas cap and trade program, vehicle emission standards, and appliance and heating emission standards.

Conclusions

Dr. Jaccard argues that the question of “how do we break our addiction to fossil fuel use?” or “how do we use less fossil fuels?” are the wrong questions as we should not be framing the debate in terms of “good” and “bad” fuels. Instead, society should focus on developing policies to create a clean energy system given human preferences and decision making processes and this will likely result in continued fossil fuel use.

2 - A Thousand Barrels a Second: The Coming Oil Break Point and the Challenges Facing an Energy Dependent World by Peter Tertzakian (Chief Energy Economist), (ARC Financial Corporation)
6 June 2006

Introduction

Peter Tertzakian of ARC Financial Corporation presented on his insights on the dependency and addiction the developed world has with oil and resulting impacts on our societies. He presented a summary of the conclusions he reached in his book, *A Thousand Barrels a Second: the Coming Oil Break Point and the Challenges Facing an Energy Dependent World*.

The presentation provided an analysis of shifts in energy trends, as well as a description of how past significant points in time (what he calls energy “break points”) developed and evolved.

Key Highlights

Mr. Tertzakian compared our relationship with energy with an evolutionary cycle that is characterized by different phases.

Economic growth is stimulated by energy which helps to fulfill the needs of a population. At this stage, a kind of dependency evolves from the relationship and the economy becomes “hooked” on oil, for example. This first phase of the cycle is called *Growth and Dependency*.

Next, pressure builds up in the economic system in the form of environmental, geopolitical, social, policy and business pressures. These pressures on the energy system find their sources on the principle of dependency. This second phase in the cycle is called *Pressure Buildup*.

At some point, the energy system comes to a *Break Point* where it can not continue to function properly, given the numerous pressures endangering the system. To survive, the energy system must experience a radical change in the technologies used to fulfill the different needs. New technology is discovered to meet energy demands and substitution of energy sources and utilization occurs. This fourth phase is referred to as the *Magic Bullet* phase.

After the energy and the economic systems have experienced these turmoils, a rebalancing of fuel mix happens and a new cycle of dependency and growth evolves until the next crisis.

Currently, exploration implies more risks and difficulties to maintain the way we use oil because costs are rising and the quality of the resource is different compared to the early oil era. Today, nations are ready to go to great lengths to locate oil, being that the resource is highly valued in our societies and essential to our lifestyles.

To illustrate this dependency-addiction relationship with oil, one example cited is the size and number of freeways all over North America. The abundance of cement reflects the car-based “culture” we live in. Additionally, transportation is the main driver for oil consumption in modern societies, even after the 1970s oil shock. The oil shocks in the last 30 years did not change the way we use oil for transportation, at least not in the western world. Income growth and economic development, such as that seen in China, creates even more addiction to oil for transportation.

Mr. Tertzakian also noted that vehicle energy consumption is linearly correlated to the weight of the vehicle. Solving this particular issue would have major impacts on our environment. One solution is to reduce the average weight of vehicles and the average weight of vehicle fleets (the North American car fleet has 230 million vehicles for example). Additionally, the effect of higher incomes (the income effect) on car purchases still creates large impacts on consumer choice, as long as consumers can afford to fill their gas tanks.

Other variables playing a role in our oil consumption include our migration to the suburbs and modern lifestyles. We drive long distances from home to work, combined with multiple displacements for an average family during an average day. The solution, however, is not a migration to the inner city, as there is not enough physical space and modern lifestyles are not accommodated. Public transportation is considered poor and there is a lack of infrastructure.

The increase in the price of oil has not caused reduction in demand or demand response. An example can be seen in China where the number of vehicles is increasing despite the higher price of oil, which reflects the dependency of modern economies on oil. Furthermore, this addiction is maintained by better fuel economy due to better mileage performance. The average North American’s reaction is to drive further in larger and more comfortable vehicles.

Conclusions

Our addiction to oil will continue. The problems in adopting alternative vehicles include their cost, their inability to travel as far as a vehicle fueled with oil, and their size, which is considered too small to accommodate current lifestyles. Government policies, such as speed limits, taxes on fuel-inefficient or heavy cars and reserved lanes for car pooling, may also ease our dependency on oil.

Other solutions to our dependence on oil include increasing awareness about consuming oil to sustain our way of living, employing moral persuasion to influence each other’s habits and relationship with oil, introducing traffic flow management and promoting teleworking or work from home. However, Mr. Tertzakian does not believe that government interventions can curb the addiction to oil.

3 - Optimistic Futures by Dixon Thompson (Professor, Environmental Science), (University of Calgary)
29 June 2006

Introduction

Dr. Dixon Thompson of the University of Calgary provided a preview of his "optimistic energy futures" work. As the National Energy Board develops energy outlooks, it is valuable to consider a wide-ranging set of viewpoints as well. The topic is very suitable since it is not focused on one energy commodity or issue, but its implications span through many. It also provides insights on taking our energy futures to the next level where environmental sustainability is as important an element as energy and the economy.

Key Highlights

The problems and solutions facing our future energy system are complex. However, there is reason to be optimistic about the future energy system. There are a number of technologies that can be deployed to improve sustainability.

The level of complexity requires an analysis of the "big picture". Sustainability issues can not be solved through academic, mono-disciplinary research, but instead requires a coordinated approach across disciplines. Dr. Thompson argues that solutions developed using integrated interdisciplinary approaches are different and better than solutions developed in silos. However, there are barriers to addressing issues through a multi-disciplinary approach, including difficulty in securing funding and garnering support from universities as well as journals.

To help solve sustainability issues, messages must be communicated in a way to help societies make appropriate decisions. Communicating a message requires the development of a different tool for each type of audience. For example, the Roger Innovation Curve, which plots how people's attitudes and willingness to apply new technologies change over time, can identify five types of audiences in which to communicate. The innovators, early adaptors, early majority, late majority and laggards all require different messages. Messages should also be targeted to those audience members who are most likely to be reached and can make the biggest difference. In this vein, Dr. Thompson suggests targeting communication efforts to innovators, early adopters and the early majority.

Conclusions

We should continue to be optimistic about the future of the energy system. There are a number of technologies and approaches that can be adopted to help us become more sustainable (for example, wave energy and plug-in hybrids). The development of a sustainable energy system requires a coordinated effort and a commitment to change. It also requires effective communication strategies.

SPEAKER BIOGRAPHIES

Christopher Theal is the Managing Director, Institutional Research at Tristone Capital. Tristone Capital is a leading North American full-service investment banking firm specializing in the energy industry. Prior to joining Tristone in 2002, Mr. Theal held positions as a Research Analyst at CIBC World Markets Inc., a Corporate Analyst for a major Canadian integrated oil and gas company, and Officer in the Canadian Navy.

Kirk Osadetz is a Research Geo-Scientist at Natural Resources Canada, specifically in the Geological Survey of Canada (GSC) offices in Calgary. Mr. Osadetz had been a Geologist in industry for a number of years starting with Gulf in the 1970s before moving to the GSC in the 1980s. In the past, Mr. Osadetz was heavily involved in undertaking conventional oil and gas resource assessments both in Western Canada and in the frontiers of Northern Canada and the offshore resources of Eastern and Western Canada. One of his newer duties involves acting as a research co-leader of the hydrates program at Mallik with Scott Dalimore, based in Ottawa. He has given numerous technical presentations both in Canada and internationally, and is recognized as an expert on gas hydrates.

Michael Hanrahan is the Managing Director for the Centre for Marine CNG Inc. The Centre is an independent testing facility with a mandate to design efficient technology for the safe transportation of marine CNG for the economic development of currently stranded offshore gas discoveries. The Centre has alliances with Canadian, Indian and Norwegian governments; companies involved in transportation and university research; and gas companies. Mr. Hanrahan has held previous senior positions with Irving Oil at the Irving Refinery Corporate headquarters, and the Liquefied Natural Gas Project in Saint John. Mr. Hanrahan has also worked in private and public sector positions, and worked on the Hibernia Project and the Goose Bay Low Level Flight Training Project.

Dan Woynillowicz is a Senior Policy Analyst with the Pembina Institute. Mr. Woynillowicz acts as a spokesperson for the Institute and has provided expert testimonials on the impacts of oil sands development before both provincial and federal regulatory review panels. The Pembina Institute is an independent, not-for-profit environmental policy research and education organization. Mr. Woynillowicz has co-authored many of Pembina's recent publications, including *Oil Sands Fever: The Environmental Implications of Canada's Oil Sands Rush; Down to the Last Drop: The Athabasca River and Oil Sands* and *Troubled Waters, Troubling Trends.*

Bob Dunbar is an expert on oil sands matters, with more than 35 years of Canadian and international energy industry experience, including more than 10 years as an energy industry consultant. Mr. Dunbar held various senior positions at the Energy Resources Conservation Board (ERCB) including Manager, Oil Sands Department, and with Petro-Canada in strategic planning, gas marketing and project development. Before resuming his private consultancy in 2005, he led the completion of several studies at the Canadian Energy Research Institute (CERI), including *CERI's Oil Sands Supply Outlook*, released in March 2004. His consulting focus is on oil sands industry business and technical issues and training.

Blaine Hawkins is the Manager of the Conventional Oil and Natural Gas Business Unit with the Alberta Research Council (ARC). His work at the Council centers on improved oil recovery (IOR) processes by chemical methods, chemical flooding optimization and reservoir sensitivity, reservoir performance and fluid flow in porous media, thermal recovery of heavy oil.

Ashok Singhal is a Senior Staff Research Engineer with ARC, whose focus is design and operation of enhanced oil recovery (EOR) methods such as waterflooding, horizontal well techniques, CO_2 enhanced recovery, water-after-gas (WAG) and hydrocarbon gas injection, as well as performing technical and economic evaluations, simulation and forecasting.

John McGinnis joined the Alberta Government's Department of Economic Development in July 2005, as Director of Hydrocarbon Upgrading. Previously, he was an Energy Management Consultant in Ontario. He also spent several years at Imperial Oil in Toronto, Halifax and Calgary, as well as with Exxon Corporation in New York and worked on a loan assignment with Aramco in Saudi Arabia. Mr. McGinnis was Chief Engineer, Development Planning for Imperial's original Cold Lake mega-project, and subsequently Manager of Business Development for the phased bitumen production scheme at Cold Lake. Later, he was also Project Manager for the design and construction of the Esso Research Centre, University of Calgary Research Park.

Allen Wright is the Executive Director of the Coal Association of Canada. The Coal Association of Canada represents companies engaged in the exploration, development, use and transportation of coal. Its members include major coal producers and coal-using utilities, the railroads and ports that ship coal, and industry suppliers of goods and services.

Bob Stobbs is the Executive Director of the Canadian Clean Power Coalition. The Canadian Clean Power Coalition is a national association of Canadian coal companies and coal-fired electricity generators. The association represents over 90 per cent of Canada's coal-fired electricity generation. The association's goal is to demonstrate that coal-fired electricity generation can effectively address all environmental issues projected in the future, including CO_2.

Dr. Bill Gunter is the Principal Scientist at the Alberta Research Council (ARC). Dr. Gunter is known for his expertise in carbon capture and storage. He is currently leading a field project involving international companies and governments in development of a process for enhancing the production of coal bed methane by CO_2 injection. The Alberta Research Council (ARC) is an applied research and development corporation that develops and commercializes technology to grow innovative enterprises, specializing in converting early stage ideas into marketable technology products and services.

Dr. Mark Jaccard is an economist by training with a PhD from the University of Grenoble in France. Since 1986, he has been a Professor in the School of Resource and Environmental Management at Simon Fraser University, where he also leads the Energy and Materials Research Group. Dr. Jaccard is also accountable for the Canadian Industrial Energy End-use Data Centre, more commonly known as CIEEDAC, also located at the Simon Fraser University. His past assignments include acting as Chair of the British Columbia Utilities Commission (BCUC) between 1992 and 1997. He was an active member of the Intergovernmental Panel on Climate Change (IPCC) between 1993 and 1996 and contributed to the production of IPCC's Second Assessment Report. For almost a decade, he has been one of six international energy experts on the China Council for International Cooperation on Environment and Development.

Peter Tertzakian is the Chief Energy Economist of ARC Financial Corporation and member of ARC's Investment Committee, one of the world's leading energy investment firms. He is the author of *A Thousand Barrels a Second* and is a highly sought-after speaker at international events and energy conferences. Prior to joining ARC, Mr. Tertzakian worked in field operations, seismic data processing and geophysical software development as a Geophysicist with Chevron. He holds a degree in Geophysics from the University of Alberta and a graduate degree in Econometrics from the University of Southampton, U.K. He also holds a Master of Science in Management of Technology from the Sloan School of Management at MIT.

Dr. Dixon Thompson is a Professor of Environmental Science in the Haskayne School of Business at the University of Calgary. Dr. Thomson has undertaken research and taught in many environmental areas, including environmental science and environmental management, product and technology assessment, life cycle assessment, water management, and environmental chemistry and eco-toxicology.

Dr. Thompson was a pioneer in the development of graduate courses in environmental management and has extensive international experience in Latin America and the Caribbean, as well as other developing countries. As a consultant, he has applied environmental management tools for resource-based industries such as Nova, Petro-Canada, Alberta Energy Company, IntraWest and BC Gas International. As well, he is the lead author for the Commission on Environmental Cooperation's work on Environmental Management Systems (EMS) for small and medium-sized enterprises.

PRESENTATIONS