21st World Petroleum Congress
Responsibly Energising a Growing World
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Unless otherwise stated, the dollar ($) values given in the book refer to the US dollar.
Unconventional oil presents the energy industry with incredible opportunities and challenges in equal measure. With this guidebook, the third one in our ongoing series, the World Petroleum Council aims to cut through the jargon and go through the many aspects of unconventional oil in clear, easy-to-understand terms.

We cannot ignore the enormous potential of unconventional oil resources that can be developed across a number of countries. This is an opportunity for many nations to become more self-sufficient, for developing countries to have better access to energy, and for enormous economic benefits to flow on from the resulting reduction in energy poverty.

In this guidebook, we explore the different types of unconventional oil, the technology that is making it possible to maximise the potential of these resources and we examine the environmental, technical and economic issues that many operators are facing.

This book also features case studies from industry leaders on how to succeed in producing oil from unconventional sources in a way that benefits all stakeholders. The sharing of knowledge and experiences can only benefit everyone in the energy industry, especially when it comes to fostering greater understanding about the production and distribution of unconventional oil. There is also a case study which focuses on the importance of strong management in the industry now and into the future – Canada’s Oil Sands Leadership Initiative is one such example in this guide of the importance of ensuring strength in the oil sand sector’s current leadership, sharing knowledge, and encouraging the career development of young professionals in the energy industry.

Projects such as the Oil Sands Leadership Initiative are important to the petroleum industry as a whole and this reflects the mission of WPC. As the issue of whether peak oil is behind us or ahead of us, we need strong leadership across the whole industry if we are to meet the major challenges faced by the oil and gas industry. Most experts agree that the four biggest challenges we face in the petroleum industry, as well as the global energy industry as a whole, are: technology, geopolitics, the environment and the world’s growing population.

As WPC’s 65 member countries seek to forge a productive path – even if there are obstacles along the way – we hope this series of expert guides will play a role in sharing knowledge and in applauding the innovation and technical achievements that are shaping the unconventional oil industry on a worldwide scale. – O/M text
WPC Vision, Mission, Values and Principles

Vision
An enhanced understanding and image of the oil and gas sector’s contribution to sustainable development.

Mission
The World Petroleum Council (WPC) is the only organisation representing the global oil and gas community. WPC’s core value and purpose centres on sustaining and improving the lives of people around the world, through:
- Enhanced understanding of issues and challenges
- Networking opportunities in a global forum
- Cooperation (partnerships) with other organisations
- An opportunity to showcase the industry and demonstrate best practice
- A forum for developing business opportunities

- Information dissemination via congresses, reports, regional meetings and workshops
- Initiatives for recruiting and retaining expertise and skills to the industry
- Awareness of environmental issues, conservation of energy and sustainable solutions

Values
WPC values strongly:
- Respect for individuals and cultures worldwide
- Unbiased and objective views
- Integrity
- Transparency
- Good governance
- A positive perception of energy from petroleum
- Science and technology
- The views of all stakeholders
- The management of the world’s petroleum resources for the benefit of all

Principles
WPC seeks to be identified with its mission and flexible enough so that it can embrace change and adapt to it. WPC has to be:
- Pro-active and responsive to changes and not merely led by them
- Creative and visionary, so that we add value for all
- Challenging, so that our goals require effort to attain but are realistic and achievable
- Focused, so that our goals are clear and transparent
- Understandable to all

**Key strategic areas**

- **World Class Congress** to deliver a quality, premier world class oil and gas congress.
- **Inter-Congress activities** to organise forums for cooperation and other activities on specific topics; and to organise regional events of relevance to WPC members and all stakeholders.
- **Cooperation with other stakeholders** to add value by cooperating with other organisations to seek synergies and promote best practice.

- **Communication** to increase awareness, of WPC’s activities, through enhanced communication, both internally and externally.
- **Global representation** to attract and retain worldwide involvement in WPC.
- **Youth and gender engagement** to increase the participation of young people and women in oil and gas issues, including the establishment of a dedicated Youth Committee for the development of active networking opportunities with young people.
- **Legacy** to create a central WPC legacy fund to benefit communities and individuals around the world based on WPC’s mission.

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**World Petroleum Congresses**

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WPC overview

Since 1933, the World Petroleum Council (WPC) has been the world’s premier oil and gas forum and is the only international organisation representing all aspects of the petroleum sector.

WPC will mark its 80th anniversary in 2013 having been established in 1933 to promote the management of the world’s petroleum resources for the benefit of all. It is a non-advocacy, non-political organisation and has received accreditation as a non-governmental organisation (NGO) from the UN. WPC’s prime function is to catalyse and facilitate dialogue among stakeholders, both internal and external to the petroleum industry, on key technical, social, environmental and management issues in order to contribute towards finding solutions to those issues.

Headquartered in London, the World Petroleum Council includes 70 member countries from around the world representing more than 95% of global oil and gas production and consumption. WPC membership is unique, as it includes both OPEC and non-OPEC countries with high-level representation from National Oil Companies (NOCs) as well as Independent Oil Companies (IOCs). Each country has a national committee made up of representatives of the oil and gas industry, the service sector, academia, research institutions and government departments. The governing body of WPC is the Council consisting of representation from each of the national committees. Its global membership elects the President and an Executive Committee every three years to develop and execute its strategy. The Council also selects the host country for the next World Petroleum Congress from the candidate countries.

Every three years, the Council organises the World Petroleum Congress hosted by one of its member countries. The triennial Congress is also known as the “Olympics of the petroleum industry”. It covers all aspects of oil and gas from technological advances in conventional and unconventional upstream and downstream operations to the role of natural gas and renewables, management of the industry and its social, economic and environmental impact. In addition to industry leaders and experts, outside stakeholders such as governments, other industry sectors, NGOs and international institutions also join the dialogue. To ensure the scientific and topical quality of the event, the WPC Council elects a Congress Programme Committee whose members are responsible for delivering the high-level content for its Congresses.

Moscow will be the host of the 21st World Petroleum Congress in 2014 (www.21wpc.com).

Beyond the triennial Congress, the World Petroleum Council is regularly involved with a number of other meetings such as the WPC Youth Forum, the WPC-UN Global Compact Best Practice Forum, joint WPC/OPEC workshops and other regional and topical events on important industry issues.

Legacy

As a not-for-profit organisation, WPC ensures that any surpluses from the triennial Congresses and other meetings are directed into educational or charitable activities, thereby leaving a legacy. The World Petroleum Council has set up a dedicated WPC Legacy Fund to spread the benefits beyond the host countries and its members and alleviate energy poverty through carefully selected projects.
The concept of leaving a legacy in the host country started in 1994 with the 14th World Petroleum Congress in Stavanger, Norway. After this Congress, the surplus funds were put towards the creation and building of a state-of-the-art Petroleum Museum in Stavanger.

The 15th World Petroleum Congress in Beijing adopted the issue of young people as a key aspect of its theme: “Technology and Globalisation – Leading the Petroleum Industry into the 21st Century”. To support the education and future involvement of young people in the petroleum industry, the Chinese National Committee donated all computer and video equipment used for the Congress to its Petroleum University.

Profits from the 16th Congress in Calgary were used to endow a fund that gives scholarships to post-secondary students in several petroleum-related fields. The Canadian Government Millennium Scholarship Foundation matched the amount dollar-for-dollar, creating an endowment which supported more than 2,000 students until its conclusion in 2010.

The 17th World Petroleum Congress was the first to integrate the concept of sustainability throughout its event. The Congress took responsibility for all the waste it generated. The congress and the accompanying Rio Oil & Gas Expo 2002 generated a total of 16 tonnes of recyclable waste – plastic, aluminium, paper and glass. All proceeds of the recycling activities were passed on to a residents’ cooperative with 6,000 inhabitants located in the port area of Rio de Janeiro.

But the sustainability efforts did not stop there – an army of 250 volunteers collected 36 tonnes of rubbish in 10 days in a special community effort to clean up the Corcovado area before the Congress, donating all proceeds to the rubbish collectors, some of the poorest inhabitants of Rio. The Finlândia Public School also received a new lick of paint from our volunteers. The surplus funds for the Congress were used to set up the

The most recent World Petroleum Congress was held in Doha in December 2011.
The WPC legacy initiative started in 1994 when surplus funds from the 14th World Petroleum Congress were put towards the building of Stavanger’s Petroleum Museum.

WPC Educational Fund in Brazil, which was further increased in 2005 with tax initiatives added by the Brazilian government.

The 18th World Petroleum Congress also chose a sustainability focus for the first-ever WPC to be held in Africa: “Shaping the Energy Future: Partners in Sustainable Solutions”. Education was the focus of the 18th World Petroleum Congress Legacy Trust, set up by the South African National Committee to provide financial assistance to needy young South Africans who wish to pursue a qualification in petroleum studies.

In 2008, with the 19th Congress in Madrid, the trend continued and the organisers selected a
number of projects and foundations to receive the surplus from the event for charitable and educational programmes in Spain and around the globe. The 19th Congress was the first one to offset all its carbon emissions and receive a certification as a sustainable event. The most recent Congress in Qatar also offset all of its carbon emissions and has chosen a project to educate and support young people as recipient for the 21st WPC Legacy Programme.

Youth outreach
Youth is a critical factor in the sustainability of the oil and gas industry. Addressing and involving young people in the design of future energy solutions is therefore one of the major issues for WPC’s 65 member countries. WPC recognises their significance to the future of the petroleum industry and the importance of giving the young generation scope to develop their own ideas, talents and competencies to create viable solutions for the future of our world.

As part of its outreach to recruit and retain the next generation, WPC created its Youth Committee in 2006 to provide a channel through which young people have a direct involvement and say in the strategy and activities of the organisation. It aims to create and nurture a collaborative, global forum for young people to be heard, to champion new ideas within the petroleum industry, to promote a realistic image of the petroleum industry, its challenges and opportunities and to bridge the generation gap through mentorship networks.

In 2011, WPC launched a pilot Mentorship Programme to provide a bridge between international experts and the next generation of our industry. This programme is now in its second successful cycle and has already created 150 matches.
WPC Member Countries

Algeria    Angola    Argentina    Australia    Austria    Azerbaijan    Bahrain    Belgium    Brazil    Bulgaria    Canada    China    Colombia    Croatia    Cuba    Czech Republic    Denmark    Egypt

Finland    France    Gabon    Germany    Hungary    India    Indonesia    Iran    Israel    Japan    Kazakhstan    Kenya    Korea    Kuwait    Libya    Macedonia    Malaysia    Mexico

Morocco    Mozambique    The Netherlands    Nigeria    Norway    Oman    Pakistan    Panama    Peru    Poland    Portugal    Qatar    Romania    Russia    Saudi Arabia    Serbia    Sierra Leone    Slovak Republic

Slovenia    South Africa    Spain    Suriname    Sweden    Switzerland    Tajikistan    Thailand    Trinidad and Tobago    Turkey    Ukraine    United Kingdom    Kingdom    Uruguay    USA    Venezuela    Vietnam
Introduction to unconventional oils

By Mark Blacklock

Unconventional oils are being exploited globally as countries seek energy security and economic prosperity.

The world has vast resources of oil which were created when organic matter was buried beneath sedimentary rocks and subjected to heat and pressure over millions of years.

As the World Petroleum Council’s Guide to Energy Fuel for Life explains, an oil or gas field “is like a sponge, not some vast underground lake: oil and gas accumulate within porous rock formations in the Earth’s crust.” Generally, a layer of impermeable rock on top stops the oil and gas from escaping but sometimes there are fissures in this layer allowing oil and gas to seep out.

While people have used natural seepages of oil for thousands of years, the modern oil industry was born in 1859 when Edwin Drake’s well on the outskirts of Titusville in Pennsylvania, USA, struck oil.

Drake’s innovation was to drill using cast-iron piping to protect the wellbore; the oil rose up the bore under the pressure of the reservoir. Typically, between 5% and 15% of the oil in a reservoir can be recovered via its natural pressure which is known as primary production. When the pressure falls to a level which does not allow free flow, the oil has to be extracted using a variety of secondary production methods ranging from simple pumping, through injecting water, CO2 or natural gas, to thermal and chemical treatments. Once extracted, the oil is shipped to refineries. The whole process is what we call conventional oil production.

In broad terms, unconventional oil is relatively immobile. It needs much more of a helping hand to be produced and has to be diluted or upgraded before it can be shipped for refining. For the purposes of this guide, we will also consider oil contained in a structure that has to be opened up with techniques considered unconventional today, although in the future they may well be considered conventional.

Tight oil is trapped in shale, rocks made up of thin layers of fine-grained sediments, typically originally laid down in rivers, lakes and floodplains. Shale formations have very low permeability and the oil is extracted by drilling – first vertically and then horizontally – and hydraulic fracturing (or “fracking”). This involves pumping a blend of water, chemicals and “proppants” (often sand) into a well under high pressure to open up cracks in underground rock formation. The grains of sand keep the cracks open and thus allow the oil to flow. Other proppants may also be used. Once extracted, the oil can be shipped for refining without treatment. The USA is the biggest tight oil producer and major tight oil formations include the Bakken, Barnett and Eagle Ford shales.

Oil shale is younger than the shale formations containing tight oil. It contains organic matter rich in hydrogen, known as kerogen. Once extracted from the ground, the rock can either be combusted directly (e.g. in a power plant) or processed by retorting to produce shale oil and other useful products. Retorting is a cracking process that breaks down kerogen to release hydrocarbons and further cracks hydrocarbons into lighter products. This can take place in a traditional refining capacity or using an in-situ process.

Production from shale oil peaked in 1981 and then declined sharply but there has been a resur-
gence of interest in the 21st century. Estonia is the main extractor of oil shale, while the largest deposits are in the Green River Formation which covers part of Colorado, Utah and Wyoming in the USA.

Heavy oil and extra heavy oil are highly viscous. Heavy oil has an API up to 22° API gravity and extra heavy oil has an API gravity of less than 10°. Some of it can be produced cold using horizontal drilling and pumping, but thermal treatment is needed for higher recovery rates. Extra heavy crude either has to be diluted by blending it with gas condensates, lighter oil or naphtha, or upgraded into what is known as synthetic crude (or syncrude) for shipping to refineries. The largest heavy oil deposits are in the Orinoco Belt in Venezuela, and the provinces of Alberta and Saskatchewan in Canada.

Oil sands are a mixture of natural bitumen with an API gravity approaching zero, clay, sand and water. The bitumen is extracted either by open-cast mining and treatment for shallow deposits, or in-situ treatment for deeper ones. It is then diluted or upgraded for shipping to refineries. The Athabasca oil sand deposits in Alberta, Canada, are the world’s largest.

Gas-to-liquids (GTL) and coal-to-liquids (CTL) are also processes whereby fuels are obtained without using traditional oil well methods. GTL involves the conversion of carbon monoxide and hydrogen for processing in a reactor produce paraffinic waxes which are then refined. The main product of a typical GTL plant is automotive diesel with virtually no sulphur or aromatics. Naphtha feedstock, kerosene for jet fuel and normal paraffin and base oils for lubricants are also produced by the GTL process. The Pearl operation in Qatar is the world’s largest GTL plant.

In the case of CTL, liquids that have been obtained via the coal liquefaction process can potentially be used as fuels or feedstocks for a wide range of useful products, particularly in the petrochemical sector.

Mark Blacklock is Editor-in-Chief at International Systems & Communications.

Ask most people what they think oil extraction looks like and they’ll picture a gusher. As we’ll explore in the pages that follow, unconventional oil discoveries tell a different story.
Shale oil

By Georgia Lewis

New technologies and discoveries of shale oil are changing the global face of the energy industry in multiple countries.

According to US Energy Information Administration (EIA) estimates, 137 shale formations in 42 countries represent 10% of the world’s technically recoverable crude oil resources, or those that can be used produced using current technology.

While the US is leading the world in production and development, more than half the world’s shale oil resources are concentrated in Russia, China, Argentina and Libya.

It is important to distinguish between oil shale and oil-bearing shales. Oil shales are sedimentary rocks containing solid organic material that converts into a type of crude oil when it is heated. It is a fine-grained, hydrocarbon-bearing rock that occurs in different countries across the world and it is largely made up of clay, silt and salts. The organic matter in the shale is known as kerogen, which is generally around 12% of the make-up of the material that needs to be refined. Like oil sands, it has a high sulphur content, up to 7%. There is also around 3% of soluble bitumen in oil shale.

There are three main types of oil shale based on their origins. Terrestrial shale is of organic origins similar to coal forming swamps, lacustrine shale has its origins in fresh or brackish water algae and marine shale comes from salt water life. Oil shale can be turned into liquid hydrocarbons by mining,
crushing, heating, processing and refining, or by in-situ heating, oil extraction and refining.

Kerogen has the potential to be an enormous hydrocarbon resource in the decades to come. In North America, the largest oil shale deposits are in Colorado, Utah, Wyoming and Alaska. In Alaska, two companies achieved encouraging results from test well and US operators applied for licences to export shale oil. There is also a block of American states bordered by Alabama, West Virginia, Pennsylvania, Missouri and Michigan with a group of large oil shale plays that have been earmarked for exploration. Outside of North America, there are significant shale deposits in Australia, Brazil, China, Estonia, Israel, Jordan, Scotland, South Africa, Spain, Sumatra and Sweden.

Oil-bearing shales contain deposits containing already formed petroleum, which are referred to as shale oil or tight oil. The oil can be extracted from drilled wells using the same hydraulic fracturing technology used in coal seam gas and shale gas production. Retorting technology can also be used which does not use hydraulic fracturing but instead uses conventional open cut mining techniques.

As well as already producing oil from oil-bearing shales, tight shale exploration is underway in America in multiple areas, including New York, Maine, Mississippi, Utah and Alaska. Beyond the...
Kennedy School’s Belfer Center for Science and International Affairs, studied the performance of 4,000 American shale oil wells and the work of around 100 companies involved in shale oil production.

According to Maugeri’s study, only the US oil industry is capable of the drilling intensity required to make the most of its shale oil resources in the long term. As of 2012, the US completed 45,468 oil and gas wells and brought online 28,354 of them, compared with 3,921 wells in the rest of the world. The US holds more than 60% of the world’s drilling rigs and 95% of the rigs in America can perform horizontal drilling which, along with hydraulic fracturing, is essential for the exploitation of shale oil.

EIA has also revised upwards the estimates for US shale oil reserves from 4 billion barrels in 2007 to 33 billion barrels in 2010. Fast production growth means dramatic local effects on pricing in shale oil-producing areas where access to export infrastructure is limited. The US domestic oil price

A large and important resource
The American shale oil revolution has emerged as an important and relatively cost-effective unconventional resource. According to the EIA, shale oil production is on the rise in the US, from 111,000 barrels per day in 2004 to 535,000 barrels per day in 2011, an annual growth rate of 26%. EIA estimates suggest that US shale oil production will rise more slowly in the future – up to 1.2 million barrels per day by 2035 – but other estimates are as high as 3-4 million barrels per day.

A Harvard University study has projected that because of the shale resources in the US, it could become the world’s largest oil producing nation by 2017. The study, conducted by Leonardo Maugeri, a former oil executive and now a fellow at the
has now decoupled from global indices and imports are forecast to decline. Thus, increased shale oil output could lead to significantly lower oil prices in the future. According to EIA figures, oil shale prices are expected to plateau around the $60-a-barrel level up until 2026, compared with estimates that could go as high as $200 a barrel for conventional oils in the same timeframe.

Shale oil could also displace a large proportion of crude oil imports to the US and create extra supply to other markets, such as China. But if China makes the most of its own shale oil resources, this would further lower its own import dependency and increase effective supply to oil-importing countries.

The unconventional oil revolution, especially in the United States, has swelled reserves and heralds a bright future for the industry.

A drill site in the Bakken oil play showing some of the fracking equipment in place.
Shale oil

Getting crude oil from shale rock remains difficult and controversial, as is also the case with shale gas extraction. Oil shale is mined using either underground- or surface-mining methods.

Oil shale needs to be heated to temperatures between 400 and 500°C to convert the embedded sediments to kerogen oil and combustible gases.

**Hydraulic fracturing**

Popularly known as fracking, hydraulic fracturing is used to drill into oil-bearing shale rock formations. This technique is also used to extract gas from shale deposits. In the shale formations, the resource is known as “tight oil.” This means the oil is found embedded within the rock itself. Unlike traditional images of enormous oil drills operating on the surface on the land, fracking is an entirely different process for extracting oil from shale rock.

The process begins with a well being drilled and lined – this is usually 10,000 feet deep, but it can vary. The drilling is then directed horizontally and a pipe that has a series of holes is inserted. This stage of the process is performed in stages along the length of the horizontal run. After that has been completed, a mixture of water, proppants and chemicals (the fracking fluid) is injected. The force of the fluid exiting through the holes creates fissures in the rock, while the proppants (usually sand) prop open the cracks. The oil flows out of the cracks and into the well. It is then pumped to the surface.

The hydraulic fracturing of tight oil is widely used in the US and Canada, such as the northern Bakken, spanning North Dakota, Montana, Saskatchewan and Manitoba; Eagle Ford, Barnett and the Permian Basin in Texas and New Mexico; the Cardium play in Alberta, Canada; in the Miocene Monterey and Antelope deposits of California; Penn Shlae in Oklahoma; Mowry-Niobrara in Wyoming and Colorado; Utica Shale in Colorado, Wyoming and New Mexico, and Exshaw Shale in Montana.

According to the “A review of uncertainties in estimates of global oil resources” report by CE McGlade at the UCL Energy Institute, shale oil resources are estimated at between 330 billion and 1,465 billion barrels worldwide. As well as the US, investment is underway in China, Russia, Argentina and New Zealand to explore, quantify and develop shale oil resources.

While the US has been a leader in developing shale resources and associated technology, other countries have also enjoyed a long history of shale oil commercialisation. Estonia first started producing shale oil in 1924 after starting work on mines in 1916, China started in 1930 and Brazil in 1981.

**Extracting and processing shale oil**

Like oil extracted from oil sands, shale oil has not been processed in vast quantities for petrochemical feedstock. The processes used for extracting shale oil are more complicated than extracting liquid crude oil from the ground.
The Colony oil shale site, shown here in 1973, was created to develop TOSCO II horizontal retorting technology. The installation could process 1,000 tons of oil shale per day.
**Surface processing**

Surface processing, commonly referred to as retorting, has been the more common of the two processes. This generally involves three steps, the first of which is mining the oil shale. This can be done by either open pit mining or underground mining, which is sometimes referred to as the room-and-pillar method. The next step is the thermal processing or retorting which takes place above ground. Retorting, which happens after excavation, is the exposure of mined rock to pyrolysis, the application of extreme heat without the presence of oxygen to produce a chemical change. Finally, the shale oil is processed to obtain a refinery feedstock as well as value-added by-products.

The disadvantages of surface processing include a large land impact and heavy water consumption during production and when disposing of waste shale. Room-and-pillar methods can be inefficient because large quantities of resources can be left behind in the pillars, which need to be cut in the shale to prevent collapse.

Vertical and horizontal retorting are both used, with technologies pioneered in the US and Scotland. An example of vertical retorting is the gas combustion retort (GCR), which was developed by Cameron Engineers and the US Bureau of Mines. It achieves high retorting and thermal efficiencies and requires no cooling water, which is important in semi-arid regions. GCR works by moving crushed shale downwards by gravity, recycled gases enter the bottom and are heated by retorted shale. Air is then injected and mixes with the rising gases. Combustion of gases and residual carbon from the spent shale then heats the raw shale above the combustion zone to retorting temperature. Finally, oil vapours and
gases cooled by the incoming shale leave the top of the retort as a mist.

Horizontal retorts have also been used for many years, involving horizontal rotating kilns to achieve pyrolysis. The Alberta Taciuk Processor (ATP) has been used in the US and Australia and its process combines gas recirculation and direct and indirect heat transfer from circulated hot solids in a rotating kiln. The ATP process is largely self-sufficient. Some of the hot processed shale is recirculated in the retort with fresh shale to provide pyrolysis heat by direct, solid-to-solid heat transfer. This process has been reported to increase kerogen oil and gas yields, improve thermal efficiency, reduce process water needs and minimise coke residue on spent shale. This helps enable environmentally safe disposal. However, the concerns with ATP surround scale-up limitations which may not make it feasible for larger commercial operations.

**In-situ retorting**

This is the technology which processes shale underground. In-situ retorting deals with the problems of mining, handling and disposing of large quantities of material, which is the case for surface retorting. In-situ retorting can also help recover more deeply deposited shale oil.

According to the US Department of Energy, true in-situ processes involve no mining. In short, the shale is fractured, air is injected, the shale is ignited to heat the formation and the oil moves through the fractures to production wells.

The heating takes place underground in the in-situ process. Between 345°C-370°C, the fossil fuel trapped within starts to liquefy and separate from the rock. The emerging oil-like substance can be further refined to a synthetic crude oil.

Using slow heating methods and lower heating requirements than those employed in surface retorting is another important advantage of in-situ methods. This means the shale oil will be of a higher quality than that produced above the ground and this, in turn, reduces the upgrade requirements before the product is delivered to refineries.

Modified in-situ processes may involve mining above or below the target shale deposit before heating to create a void space of 20 to 25%. The shale is heated by igniting the top of the target deposit and recovering fluids ahead of or beneath the heated zone. Modified in-situ processes can improve performance by heating more of the shale, improving the flow of gases and liquids through the rock formation and increasing the volumes and quality of the oil produced.

Royal Dutch Shell has developed the In-Situ Conversion Process (ICP) to simplify the refining process for shale oil. With ICP, the rocks are not excavated from the site. Instead, holes are drilled into the shale and heaters are lowered into the earth. Over the course of at least two years, the shale is slowly heated and the kerogen (the fossilised material in rock that yields oil when heated) seeps out. The kerogen is then collected onsite and pumped to the surface for further refining.

![Diagram of the in-situ process](image-url)

Using the in-situ process, the oil shale is heated to release kerogen which is then pumped to the surface for processing.
Managing environmental issues

It is not surprising that the use of hydraulic fracturing has been controversial. There is one line of opinion that believes the use of fracking is and will continue to be a vital part of oil and gas production, especially in the US. While the US oil market is experiencing growth in the shale oil sector, production is expected to rise enormously over the coming decades and reduce the American reliance on imported oil.

However, there is another school of thought that believes the importance of hydraulic fracturing has been considerably overstated, will not be effective in reducing energy prices – and will come at a heavy environmental cost. There have been calls for greater transparency among shale oil producers as to the chemicals used in fracking – some operators publish the names of the chemicals they use but not all do this.

Determining the carbon footprint of any unconventional oil, including shale, is complex. One of the main challenges is attributing carbon flows from each of the upstream products to downstream products, as well as the emissions generated in extraction and refining. Oil sands and oil shale are both estimated to contain roughly three times as much carbon as conventional oil, a similar figure to that of coal. While there are knowledge gaps in the environmental impact of shale oil production, and policymakers are still trying to formulate workable regulations in many countries, some companies are taking voluntary steps to try and reduce the environmental impact of their activities.

Since oil shale development commenced in the US in the 1970s, improvements have been made to American regulations and technologies. Maturation of environmental laws and regulations has resulted in more stringent standards and requirements, new technologies have improved efficiency, and effluents and emissions are reduced or better controlled.

According to the US Department of Energy (DOE), both true and modified in-situ processes are challenged by the potential for contamination of groundwater by pyrolised oil and other metals and toxins that may be left behind.

The DOE has summarised the main environmental impacts of oil shale development. These include land impacts, water quality impacts and air quality impacts.

**Land impacts** These include the effects if oil shale is extracted using open-pit (surface) mining. This can cause surface disturbance and affect surface-water run-off patterns. However, using the example of industries such as coal mining, impacted lands can be restored with reclamation programmes. When underground techniques are used, there is less surface disturbance but the effects can include run-off and fugitive dust emissions from transport and storage.

Spent shale is generated by surface retorting, although retort technology has improved to reduce residual carbon, making spent shale better suited for landfill disposal. Backfilling will be used in both surface and underground mines, while some spent shale will be recycled as commercial building materials.

In-situ production has impacts that are similar to those experienced in oil and gas drilling operations. Heating holes and wells will usually require plugging and abandonment when heating and production operations have been exhausted.

Other surface impacts can occur in conjunction with the construction of surface facilities, including retorting, upgrading, storage, transportation, roads, pipelines and utilities.

**Water quality impacts** Run-off from mining and retorting operations have a greater impact when in-situ operations are taking place and controls are required to protect groundwater. In-situ operators have been especially challenged to protect groundwater from contamination by kerogen oil, other produced gases and sediments.
Effective technologies have been developed to manage groundwater contamination issues, such as freeze-wall technologies which isolate groundwater from subsurface in-situ processing areas until post-production flushing and clean-up of heated areas has been completed.

**Air quality impacts** Heating carbonate rock to temperatures up to 500°C generates not just kerogen oil and hydrocarbon gases but also a slate of other gases including oxides of sulphur and nitrogen, carbon dioxide, and water vapour, as well as fugitive dust and particulate matter.

Commercially available stack gas clean-up technologies, pioneered in electric power generation and petroleum refining facilities, have improved over the years and should be effective in controlling oxides and particulates emissions.

Carbon dioxide may need to be captured and used in other commercial applications, such as improved oil recovery or coalbed methane operations, or otherwise sequestered. If there are depleted oil and gas reserves in an area where shale oil development is taking place, these may be effective sequestration targets.
The US and Canada may lead the way in oil shale production but there are still unexploited plays such as Utah’s Uinta Basin to be explored.

Global round-up
The future of shale oil production is looking promising in many markets with 2012 proving to be a watershed year for many countries and producers. In 2012, numerous milestones were achieved in the drive towards expanded shale oil production in multiple markets apart from the US and Canada, the two most successful commercial shale oil producers.

There is much activity across South America. In Argentina, YPF, the national oil company, signed an investment agreement worth up to $1.5 billion with Chevron to explore and develop shale oil in Argentina’s Vaca Muerta area. In Columbia, an auction of 115 blocks of land for exploration and development of shale oil resources was held, with successful bidders including Royal Dutch Shell, Repsol SA, Ecopetrol SA and Gran Tierra Energy Ltd.

Meanwhile, in Mexico, plans are underway to invest in a project worth $242 million to assess unconventional energy potential in the Galaxia block of the Burgos basin and the Limonaria block in the Tampico-Misantla basin, both in the north-eastern part of the country. The project will be carried out by the Mexican Petroleum Institute with the participation of Petroleos Mexicanos (the state oil company commonly known as Pemex).

Venezuela’s shale oil reserves are managed by the government-owned Petróleos de Venezuela and revenues have been invested to fund social welfare programmes. However, there are questions as to how sustainable this will be in the long-
Argentina’s YPF is working with Chevron to develop shale oil in the Vaca Muerta shale of the Neuquen Basin.

Top 10 countries with technically recoverable shale oil resources

<table>
<thead>
<tr>
<th>Country</th>
<th>Billion Barrels</th>
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<tbody>
<tr>
<td>Russia</td>
<td>75</td>
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<tr>
<td>US</td>
<td>70</td>
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<tr>
<td>China</td>
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<td>Libya</td>
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<td>Australia</td>
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<td>Mexico</td>
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<td>Pakistan</td>
<td>5</td>
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<td>Canada</td>
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Global total: 345 billion barrels.

Source: EIA estimates, 2013
term as there has been a parallel lack of investment in infrastructure and subsequent fall in oil production, for all types of oils.

China National Petroleum Company (CNPC) is in negotiations with Royal Dutch Shell and another firm to look at joint ventures for exploring shale oil reserves. With China’s growing economic power, the addition of shale oil production to its energy mix and economy has the potential to be a game changer. The exploration is slated to take place in the Santanghu basin of the Xinjiang Uygar autonomous region with CNPC and Shell already in a production-sharing contract for a shale gas block in the Sichuan province.

Russia announced plans for tax breaks for shale oil producers which will come into force on January 1, 2014. There will be zero extraction tax on producers who exploit oil from shale and other tight rock formations, as well as offshore oil producers.

In Estonia, the Enefit company commissioned its second major plant Enefit 280 and it is expected to become fully operational by 2016.

Japan also made early steps towards shale oil production with Japan Petroleum Exploration (Japex) recovering a small quantity of crude oil in shale oil testing in the Ayukawa oil and gas field in Akita, northern Japan. This may prove to be great news for the Japanese energy industry with oil and gas needs spiking after most of the country’s nuclear power stations were closed in the wake of the Fukushima disaster.

In 2012, Iran announced it found 15 new oil and gas layers and it will start exploration for shale oil and gas by the first quarter of 2014. This is slated to take place in the Zagros region of western Iran. Iran is an oil exporter but it has been
An Enefit rig drilling in Jordan. Exploiting shale oil reserves will provide a welcome boost to the Jordanian economy.
struggling to sell from its enormous conventional oil reserves because of Western sanctions over its disputed nuclear energy programme.

While Libya can boast extensive oil shale resources, ongoing instability in the country has caused problems for the sector. In 2013, production fell to less than one million barrels per day, which was attributed to ongoing protests that forced the closure of oil fields and production facilities, along with security concerns leading to international oil companies to either pull out of Libya altogether or reduce their presence. The political and economic fortunes of Libya will be closely watched by oil industry observers in the coming years with 95% of the country’s revenues coming from crude oil and gas exports.

Jordan has also made the most of shale oil reserves, offering its economy some hope in the form of oil like many of its Middle Eastern neighbours. The Jordanian Ministry of Environment has given the green light for an oil shale-fired power plant, after the submission of an environmental impact assessment by Enefit, the Estonian company which will be operating the plant. It will be an air-cooled plant to minimise water usage and it...
is expected to start generating electricity for local consumption by 2017.

The announcement of shale oil reserves in Pakistan is potentially good news for the country’s economy but there is still much work to be done to determine the best ways to extract the estimated 9 billion barrels worth. Investing in the required technology may prove too expensive for Pakistan without the financial support of foreign companies. However, the human capital is certainly there with many Pakistanis already working in the oil industry in the Middle East and elsewhere so there is certainly potential.

New Zealand’s East Coast Basin contains two thick shales, the Whangai and the Waipawa. Previously, these shales were not targeted for exploration because they were thought to be too tight for historic technology. But, with advances in unconventional oil extraction, there is renewed interest from the government in testing the viability of extracting shale oil in New Zealand with a view to commercialisation.

In 2013, Australian energy company Linc Energy announces the discovery of 233 billion barrels of shale oil resources. It is estimated that around 3.5 billion barrels, worth almost $360 million, will probably be recovered.

Georgia Lewis is the Deputy Editor of International Systems and Communications.
Oil Sands

By Wishart Robson

Canada is leading the way in oil sand development with new technologies at the forefront.

The creation of oil sands is caused by the slow deposition of sediments and the pressurised decay of organic matter. These are naturally occurring mixtures of water, clay, sand and a very viscous (tar-like) hydrocarbon known as bitumen.

Canada ranks third in the world's oil reserves and this is largely because of the Athabasca Wabiskaw-McMurray oil sands deposits in the province of Alberta. The Canadian oil sands are the world's third largest oil reserve after Saudi Arabia and Venezuela, and Canada is one of the few remaining countries where oil development is open to the private sector. These oil sands are found in Cretaceous-age deposits laid down over Devonian limestone when this western region of Canada was covered by a large inland sea.

In Canada, the oil sands are variously described as petroleum that exists in the semi-solid or solid phase in natural deposits. Bitumen is a thick, sticky form of crude oil, so heavy and viscous that it will not flow unless it is heated or diluted with lighter hydrocarbons – in short, it is much like molasses. Current production of Canada's oil sands is at about 1.5 million barrel per day.

Oil sands have also been found on Melville Island in the Canadian Arctic islands, Kazakhstan, Russia, Madagascar, the Republic of Congo, and the United States.

The Melville Island oil sands are not likely to be exploited commercially in the foreseeable future. However, reserves in Kazakhstan's North Caspian Basin; Russia's Tunguska Basin, East Siberia, Timan-Pechora and Volga-Urals basins; Madagascar's Tsimiroro and Bemolanga deposits; the Congo Basin; and the American state of Utah are all likely to be commercially extracted or exploitation has already commenced.

Historically, oil sands were exploited by stripping off the overburden and exposing the bitumen layer, which is generally around 100 feet thick – then subsequent excavations were done using large shovels and trucked to processing facilities. However, mining is only feasible when overburden is up to 200 feet thick, making most of the bitumen resource too deep to mine. As a result, only about 20% of the bitumen will be mined and the remaining 80% has to be exploited using different in-situ extraction techniques.

The mines process the excavated material in several stages. Initially, the bitumen is separated from the sand/clay matrix. This process requires large volumes of water, most of it from recycled sources.
Oil Sands

Steam Assisted Gravity Drainage
The most common in-situ technology in use today in oil sands is Steam Assisted Gravity Drainage (SAGD). It is the first commercial technology used to extract bitumen by injecting steam into the reservoir. This heats and mobilises the oil so that it flows by gravity to a second well and it is then pumped to the surface for processing.

More specifically, SAGD utilises two wells drilled horizontally into the bottom of the bitumen layer with one well located five metres above the lower well. At the start of the operation, steam is injected into both wells with the intent of creating a steam chamber where the combination of heat and pressure will mobilise the bitumen. This causes the bitumen to fall by gravity to the lower wellbore. Prior to starting production operations, steam injection to the lower well is terminated so that the bitumen and condensing steam can be collected via narrow slots in the well casing and pumped to the surface.

In-situ technologies are designed so that an absolute minimum of sand or clay are pumped with the bitumen to the surface production facilities. Water use is measured by tracking the steam injected into the reservoir and the water recovered. The bitumen may be prepared for shipment to an upgrader by the addition of diluents (generally diesel fuel which can be recovered or recycled) or upgraded on site. As a result, a wide range of upgraded products are produced. An example is the Nexen-operated Long Lake facility which produces a premium synthetic crude which resembles a clear mineral oil.

Cyclic steam stimulation
While SAGD is the more popular method of extraction for oil sands, cyclic steam stimulation (CCS)
is sometimes used. CSS is currently used at Imperial Oil’s Cold Lake project and CNRL’s Wolf Lake-Primrose project, both located in Alberta, Canada.

This method can be applied to heavy-oil reservoirs to boost recovery during the primary production phase. CSS is used to assist natural reservoir energy by thinning the oil so it will more easily move through the geological formations to the injection/production wells. It can also be used as a single-well procedure.

To utilise this enhanced oil recovery (EOR) method, steam is injected into wells that have been drilled or converted for injection purposes. The wells are then shut in to let the steam to heat or “soak” the producing formation around the well. After enough time has elapsed to allow for adequate heating, the injection wells are back in production until the heat is dissipated with the produced fluids.

This cycle of soak-and-produce is known colloquially as “huff-and-puff”. It can be repeated until the response becomes marginal because of declining natural reservoir pressure and increased water production. Once this stage is reached, a continuous steamflood is then initiated to continue the heating and thinning of the oil and to replace declining reservoir pressure so that production may continue. Once steamflood is commenced, some of the original injection wells are then converted for use as production wells, along with the others drilled or designated for that purpose.

**Greening the oil sands**

It is clear that unconventional hydrocarbon resources will play an increasingly important role in meeting regional and, in some cases, global energy demand. For example, the Canadian oil sands, with oil in place estimates of 1.7 trillion billion barrels, are projected to produce about 170 billion barrels of bitumen with current technology. This makes it second only to Saudi Arabia. But at what environmental and social cost?

The oil sands were initially exploited using a variety of surface mining and extraction techni-
Cyclic steam stimulation

Huff
Steam is injected into the reservoir and the wells are then shut for a period of time.

Soak
The steam and condensed water are left to heat and dilute the oil-bearing sands.

Puff
The wells are reopened. Heated oil and water are pumped to the surface for processing.
There are four main environmental impacts related to oil sands developments. They are:

- Land disturbance
- Water quality and quantity
- Tailings ponds
- Greenhouse gas emissions

**Land disturbance**

Satellite imagery, photojournalism and documentary films have all been employed to depict the scale and/or destructive nature of oil sands development. The oil sands mines clear land and remove overburden to expose the bitumen layer. Additionally, mining entails the development of tailings ponds. Conversely, in-situ extraction disturbs about 10% of the surface area of a mine.

Using the Alberta example, here the oil sands cover approximately 140,000 km². They are located under a portion of Canada's boreal forest, which occupies an area of some 3.2 million km², covering 60% of Canada's land area – in other words, if all of the oil sands were developed, less than 0.05% of the boreal forest would be disturbed. However, the oil sands mineable area is less than 5,000 km² with the mining area currently under development at around 530 km². To put that number into perspective, that is about the size of the city of Toronto.

Reclamation, or perhaps the rate at which reclamation is being undertaken, has been, and continues to be, a matter of contention with oil sands mining opponents. The Alberta government requires that companies return the land to a sustainable landscape that was as good as, or better than it was before the development commenced. The two largest oil sands operators, Syncrude and Suncor Energy, have already reclaimed and restored vast areas to productive land use.

The Nexen-operated Long Lake in-situ lease covers an area of 29,256 hectares. Of that area, 15% has been disturbed by the construction of well pads, pipelines and production facilities. Nexen has already reclaimed two-thirds of the area disturbed and planted 347,000 seedlings as part of the reclamation effort.
In its 2010 review, Environmental and Health Impacts of Canada’s Oil Sands Industry, The Royal Society concluded: “Research indicates that sustainable uplands reclamation is achievable and ultimately should be able to support traditional land uses.”

The report also notes that “reclamation and management options for wet landscapes derived from tailings ponds have been researched but are not adequately demonstrated.” The Royal Society report then went on to say that they had concerns with the systems and practices for obtaining financial security for reclamation liability so as to avoid claims on the public purse. However, the government of Alberta continues to evaluate the system, and the amounts companies pay to deal with end of life reclamation.

**Water quality and quantity**

Water, whether it is used in the extraction process, in mining or in steam generation for in-situ extraction, is fundamental to all aspects of the production of bitumen and on-site upgrading, just as it is for the production of most consumer goods. On average, the mines require about eight barrels of fresh water per barrel of synthetic crude (about half this water is recycled from tailings ponds).

In the Alberta operations, the Athabasca River is the primary source of make-up water. Much has been made about water withdrawals, particularly in low-flow under-ice conditions. Water removals from the Athabasca River are regulated by a government management framework. In the future, companies may be required to construct water storage facilities for use during the winter months when lower river flows are experienced.

In-situ operations require about a barrel of water to produce a barrel of bitumen. Most in-situ operators use lower quality high-saline groundwater that is not used for domestic or other industrial purposes. Up to 90% of the water recovered from the wells during production operations is
A view of the same tailings pond from 2002 (above) and August 2010 (below). Having been in use for 30 years, it is expected to become a productive mixed wood forest and wetland environment in future.
recycled to the steam generators. This results in a diminished need for make-up water.

Studies on the regional cumulative impact of groundwater use have started but more needs to be done. In particular, a better understanding needs to be developed in regard to the relationship between the surface and ground water with respect to recharge rates. Water stored in tailings ponds has exhibited acute toxic effects on organisms. The tailings ponds need to be sized to allow sufficiently long residence time for mining effluents so that the toxicity levels drop to regulatory approved levels before discharge.

Concerns have been raised about residual toxicity to fish, which are part of the food supply for aboriginal peoples living downstream. As the bitumen layer outcrops in some places along the banks of the Athabasca River, separating the impact of chemical compounds in mine discharges from the impact of high levels of chemicals associated with natural seeps is an ongoing challenge for operators.

**Tailings ponds**

Tailings ponds provide several important functions for all mining operations, including oil sands mines. First, they are a repository for the waste material from the separation of bitumen, water, sand and clay, as well as small amounts of residual bitumen from processing operations. In a properly working pond, water rises to the top and the heaviest material (mostly sand) falls to the bottom. In between is a layer of clay particles suspended in the water column.

The ponds should be sized to provide sufficient retention time for the effluents directed there to be treated to a level where they can meet regulatory controls before being discharged.

Historically, it has taken longer for the suspended clay particles to settle. Dewatering of this suspension is at the forefront of research by operators, governments and academia. Suncor Energy has become a leader in this arena by moving the research from the laboratory to the field and has successful dewatered/reclaimed an old tailings pond in a matter of months, compared to the years that it can take via the natural sedimentation process. Suncor Energy has offered to share its technology at no cost to other operators.

Another option for the remediation of tailings ponds is the development of end pit lakes. End pit lakes are created by taking a portion of the mined-out area, contouring to create a depression into which tailings are placed and then capped with an impermeable layer of clay. Fresh water is used to fill the remaining space, thus creating a lake that can become part of the reclaimed landscape.

**Greenhouse Gas Emissions**

Arguably, no other topic galvanises debate about the oil sands more than the role of oil sands in the context of obligations under the Kyoto Protocol and the Copenhagen Accord. In the case of Canada, emissions from oil sands operations comprise about 5% of the country’s total greenhouse gas (GHG) emissions – in other words, the oil sands represent 0.01% of global emissions. To further put oil sands GHG emissions into context, see figure 2 which compares oil sands emissions with emissions from coal-fired electricity generation in North America.

A significant and growing percentage of oil sands production is exported to the United States from Canada. Companies, governments and consultants have conducted life cycle emissions on a range of oil sands bitumen and synthetic crude production and compared their GHG intensity to that assumed, inferred or estimated for other US domestic crudes and other crudes imported into the US. Consider any barrel of oil produced in a field, transported to a refinery, converted into a range of products, including diesel and gasoline, distributed to wholesalers and then put into vehicles and combusted.
Twenty per cent of the lifecycle emissions come from all the activities up to the point where the fuel is pumped into the vehicle and 80% of the life cycle emissions are associated with the combustion of the fuel. That is a wells-to-wheels analysis – but the combustion and efficiency of engines which combust fuels also needs to be considered in any analysis of the environmental impact. The two analyses obviously give different results – industry generally prefers the wells-to-wheels analysis to demonstrate that consumption presents a bigger challenge than the production, while others, perhaps not wanting to deal with consumers, only focus on the life cycle of the production.

Cambridge Energy Research Associates conducted one of the well-to-wheels analyses and concluded that life cycle emissions of the average oil sands barrel were 5-15% higher than the average of the basket of other crudes imported into the US. That result has been confirmed by others, including Jacobs Engineering, but this rather academic exercise is not the full story – over the past 20 years, energy use and other efficiency gains have reduced the intensity (kilograms of carbon per barrel of output) of oil sands production by almost 40%.

There is good reason to be optimistic that further reductions in carbon intensity will be realised in the future. For example, Alberta has put in place regulations in 2007 which require all facilities emitting more than 100,000 of CO2e to reduce carbon intensity of their output by 12%. Companies unable to make internal reductions were allowed to invest in a suite of Alberta-based offsets or contribute to a Technology Fund whose goal was to invest in technologies that would “green” Alberta’s oil and gas production and have a similar effect on other emitting sectors of the provincial economy.

**What lies ahead for Alberta**

The oil sands of Alberta have attracted most of the large international oil companies, as well as a...
growing number of national oil companies. In addition to the $120 billion capital spent from 1997 until 2009, the companies have collectively spent $91 billion on operating expenses and paid $17 billion in royalties. These companies understand that technology will unlock the resources and lead to more efficient operations with better environmental performance.

While there is fierce competition for resources, capital, personnel and low-cost operations, the areas of environment, health and safety have for years been the beneficiaries of the view and practice that the performance of the industry as a whole had an impact on every company, even those with sector-leading performance.

Likeminded oil sands operators created the Oil Sands Leadership Initiative (OSLI, see page 48) – this group has pledged to work cooperatively on the environmental challenges faced by operators.

The scale of development is impressive in terms of capital deployed and production growth but the development of oil sands is associated with a range of environmental and social issues that have attracted the attention of activists and the media.

In the case of Canada, the industry and its regulators within the government of Alberta work hard to identify and mitigate site-specific and cumulative impacts. Sophisticated air and water monitoring programmes are in place. The operators, both individually and collectively, are working on new technologies and processes to improve the rate of reclamation, reduce the amount of water and energy used and cut associated emissions when producing each barrel of bitumen.

Conclusions
No form of energy that we know today is without impacts of some type, magnitude and importance to individuals, groups or communities. The sheer scale of the oil sands is cause for concern for some and optimism for others. Rex Murphy, a respected Canadian political and social commentator, made the following observation after the publication of an article on oil sands in National Geographic: “Getting oil out of the ground has never been pretty. Getting anything out of the ground has never been pretty. ‘An open wound on the fair bosom of Mother Nature’ could be the caption for every single mine that has ever existed on this Earth. Getting oil from the oil sands will be, during the process, even more scarifying. I would like to offer some counter thoughts. If we want to live the way we do in the 21st Century, and apparently we do, if we want to have jobs, houses, universities, cars, communications, a military, a transportation network, getting stuff out of the ground and finding energy to run the world is absolutely a necessary thing.”

These are not popular comments in a world where there is an absence of real dialogue about our collective energy future. The scathing responses to Rex Murphy’s candid assessment is indicative of the challenges primary energy producers face day-to-day in a world where there is so little understanding of how energy reaches the homes and vehicles of consumers. Working at the physical and technical frontiers of oil exploration and production adds another complicating variable. The oil sands operators and regulators understand that modern society has expectations about the goods and services they rely upon and polling indicates that superior environmental performance is a very important issue.

The oil sands industry has a track record of innovation and the application of technology and management expertise. The challenges of today and tomorrow will be met with the same sense of optimism even as a new generation of professionals starts to exert its influence, values and expectations upon the prudent development of our global economy.

Wishart Robson is Climate Change Advisor to the CEO and President, Nexen, Canada
Upgrading in oil sands production

By Mike Ashar

What is upgrading and what is its future for the oil sands sector?

Upgrading can mean many things to many people, but in the realm of oil sands production, it usually refers to the production of useful syncrudes from oil sands after the product has been extracted from the ground.

In general, upgrading can be broken into two categories:

- Primary upgrading: The removal of carbon from bitumen (e.g., coking) or adding hydrogen to bitumen, or a combination of both. Primary upgrading produces a product lower in viscosity and higher in API gravity (the American Petroleum Institute’s measurement for the relative density of petroleum liquids). Conducting primary upgrading in a location near the resource reduces the need for acquiring and transporting large quantities of diluent.

- Secondary upgrading: The hydroprocessing of products from primary upgrading to make a higher quality, more saleable product. Each operator is likely to have different capabilities in terms of their ability to produce syncrudes from oil sands. There are many potential reasons to upgrade but the three main ones are:
  - Concern that heavy-light differentials will be large, volatile and erode project economics.
  - The cost and availability of diluent are problematic issues.
  - Upgrading (and potentially refining) makes value-creating business sense.

While upgrading may look attractive to many producers, challenges from rising capital costs, dilution of experienced personnel, an ageing and limited construction workforce, and increasing focus and cost to manage environmental, health and safety issues can all conspire to make upgrading a challenging undertaking.

Oil sands companies work individually and in consortiums to help develop new ideas for bitumen upgrading. The Upgrading Research Group at the Canadian Oil Sands Network for Research and Development (CONRAD) and the Hydrocarbon Upgrading Demonstration and Training Facility (HUDTF) industry/government group have both spent a significant amount of time and money in recent years looking at emerging technologies and how they might be advanced.

Emerging technologies of particular interest include slurry hydrocracking (combining catalyst cock-
Unconventional Oil

Upgrading in oil sands production

Shell Scotford includes a refinery, chemicals plant and oil sands upgrading facilities capable of producing 255,000 barrels per day of synthetic crude.

tails with slurry reactor designs and catalyst capture-and-recycle schemes, ENI Chevron, Headwaters and Mobis all working on this technology) and cross-flow coking (this is being developed by ETX Systems and claims to have higher yields and lower capital expenditure than conventional coking processes).

In-situ upgrading is not new but new developments are continually being made. Shell has been piloting its own in-situ conversion process (ICP) at an oil shale lease in Colorado and this may be transferable to carbonate oil sands. Petrobank Energy claims their toe-to-heel air injection (THAI) process causes some partial conversion of bitumen in-situ and it is in the demonstration phase at the Whitesands project.

During the THAI process, air is continuously injected into the deposit to create a wave of combustion. This pushes recoverable and partly upgraded oil towards a production well or production portion of a well.

Alternatively, some companies in Alberta, including BP-Husky, Encana-ConocoPhillips and Marathon, have announced projects which integrate production of bitumen in-situ with further downstream upgrading at refineries.

The main trends in the oil sands industry between now and 2030 include:

- Substantially increased production.
- A broader range of crude oils.
- Increased marketing orbits for Alberta oil sands crudes.
- A richer set of opportunities to enable refiners of oil sands crudes to improve their profitability.

Mike Ashar is the former President, Suncor Energy, Canada
The Canadian Long Lake Project is the first project to integrate Steam Assisted Gravity Drainage (SAGD) cogeneration and onsite upgrading in the Athabasca oil sands and globally. The SAGD project alone is the largest single phase project development to date. The upgrader produces synthetic crude designed to be a substitute for globally declining light sweet crude supply, and also produces a synthetic gas which is used to generate steam and electricity making the overall project largely self-sufficient.

Until recently, the primary means of extracting bitumen was surface mining but more than 80% of bitumen is buried too deep to be economically mined in this way. The commercialisation of SAGD has provided a technical solution to extract the vast majority of the resource.

To commercialise SAGD, three major economic challenges had to be met by Nexen in the Athabasca oil sands region. They are:
- Managing the cost of natural gas to generate steam.
- Managing the cost of diluent to blend the bitumen for transportation to refineries.
- Ensuring a fair price was received for raw bitumen, as bitumen pricing can be volatile.

A number of primary and secondary upgrading processes were reviewed over several years by Nexen. This resulted in an integrated design which overcomes these challenges. The Long Lake project takes 6-10° API gravity oil and upgrades it to 39° API synthetic oil. The integrated solution developed to attain this final product addresses the three main economic challenges. As a result, the Long Lake project is largely self-sufficient with respect to natural gas – it exports co-generated power to market and produces premium synthetic...
crude which requires no diluent, and it is a substitute for declining production of light sweet crude oil.

The primary technology that Nexen has used for developing the Long Lake project is SAGD, which was developed in the 1970s. As SAGD was commercialised, Nexen saw the potential for growth in the area of oil sands in the Athabasca region. As well as the technical subsurface challenges of implementing SAGD operations, it was critical to develop a concurrent business model for a commercial project that would provide the greatest potential for success. The three main economic issues had to be addressed, along with making allowances for the capital cost required to develop a SAGD project.

From 2000 until 2002, this led Nexen to examine integrating SAGD with in-field upgrading. The process used by Nexen takes advantage of conventional technology found in many refineries across the world. However, the components were configured in a unique way. The first unit, developed by OPTI Canada, recovers a liquid asphalt...
Case study: The Canadian Long Lake Project

The project is a net power exporter, thus eliminating the cost of electricity as an operating cost. The operating cost advantage of the integrated solution allowed Nexen to move into a joint venture with OPTI Canada in 2001 to develop oil sands leases. The joint venture began by strategically increasing bitumen in place that could be exploited by the two companies. This was achieved by acquiring additional crown leases, and by delineation programmes on all leases. This means there are more than 1,400 wells for Nexen and OPTI to assess for bitumen.

The Long Lake project is designed to produce 72,000 barrels per day of bitumen and 60,000 barrels per day of synthetic oil. The immense resource base and the integrated solution is a long-term investment that allows for ongoing development of multiple phases on a continuous basis. Transportation is also important to the operations. The project is connected to pipelines for North American refinery access, to the Alberta power grid for
tene which is then gasified to create a synthetic gas. Thanks to liquid asphaltene gasification, the project is largely self-sufficient in fuel for steam generation. The primary and secondary in-situ upgrading of the bitumen to 39° API means that no diluent is required for transportation. Additionally,
electricity sales, by rail for butane and sulphur sales, and by road for limited bitumen movement.

Development of the oil sands has two emerging economic drivers that have become more important since the original business plan was developed – mitigating greenhouse gas (GHG) emissions and water management. Although Canada’s GHG emissions represent less than 2% of all global emissions (with oil sands contributing less than 4% of Canada’s total emissions), oil sands projects, given their size, are large single-source emission sites. Long Lake has the capability to be compliant with new regulations with some modifications. The gasification technology used at Long Lake allows the potential capture of CO₂ onsite and its sequestration via pipeline infrastructure.

Fresh water use is a growing global issue. The vast majority of fresh water allocation in Alberta is for agriculture. The current total allocation of the Athabasca River for oil sands projects is less than 1% of river flow (See, Water quality and quantity, page 46). Mining projects use the water in the physical separation of bitumen from sand and in the upgrading process for hydrogen and to reduce air emissions.

SAGD projects require water for steam generation but government regulations require that SAGD projects recycle more than 90% of the produced water to minimise the draw on water resources. Most of the water in Nexen and OPTI’s Athabasca project is recycled and only a small amount is disposed of in underground formations. Long Lake uses mostly saline formation water and future phases will use entirely saline water for steam generation. None of the water from oil sands projects is returned to the Athabasca River – this is to eliminate man-made contamination.

John Birdgeneau is the Vice President, Technology, Nexen.
Oil sands water use and environmental management at Long Lake

- Water use from Alberta River basins.
- Environmental advisor Megan Storrar using a Heron H.Oil interface meter to measure the thickness of floating or sinking hydrocarbon products in ground water at one of Long Lake’s metering stations.
- Environmental technician William Van Der Weide, seen here changing the filter on a passive air monitor at well pad 7.
- This handheld multi-parameter instrument simultaneously measures dissolved oxygen, pH, conductivity, temperature, salinity, total dissolved solids and the oxidation-reduction potential in the surface water at a creek near well pad 12.

![Graph showing water use from different basins: Athabasca, North Saskatchewan, South Saskatchewan.](Source: AENV state of the basin website)
Case study: The Canadian Long Lake Project
The Oil Sands Leadership Initiative

By Dr Vincent Saubestre

Canadian oil sands operators are working together to meet the challenges faced by the sector.

The Oil Sands Leadership Initiative

In 2010, Conocophillips Canada, Nexen Inc, Statoil Canada, Suncor Energy Inc and Total E&P Canada signed a charter agreement to launch the Oil Sands Leadership Initiative (OSLI). This initiative is committed to achieving significant improvements in their environmental, social and economic performance in developing Canada’s world scale oil sands resources. Shell Canada signed the charter in 2011. Canadian Natural Resources and Husky Energy also contributed to individual projects in 2012.

Since 2009, OSLI has initiated more than 50 projects aimed at addressing the challenges posed to industry, and deployed a collaborative structure regularly involving more than 100 staff from the aforementioned companies. The government of Alberta is an active observer and advisory panels and critics are convened to provide feedback on its activities.

In 2012, based on the success of the OSLI collaborative model, the members decided to transition all environmental activities (Land, Water, Green House Gases and Tailings) to the newly established Canada’s Oil Sands Innovation Alliance (COSIA). COSIA is made up of 14 companies (including all OSLI members) and it represents
90% of oil sands production in Canada. From 2013, Technology and Community projects are being pursued by the COSIA’s OSLI members with a view to invite participation from other members.

The pillars that underpin OSLI are collaboration, innovation, stakeholder engagement and deployment to the field.

**Collaboration**

OSLI is a collaborative network of companies and advances in best practices and technological processes are shared. The OSLI Steering Committee meets four times a year and support comes from the highest levels of the companies.

**Innovation**

OSLI reaches out to universities, research institutes and technology developers beyond the oil sands industry. For example, OSLI worked with Massachusetts Institute of Technology (MIT) on the International Genetically Engineered Machine (iGEM) competition. OSLI has supplied financial support, tailings samples, and access to experts and materials to students involved in this competition. It is also supporting the work of universities in Canada, Hungary and the Netherlands.

**Stakeholder engagement**

OSLI established an advisory panel to work with the management committee. This is made up of a cross-section of stakeholders. They have been described as “critical allies” and they are invited to challenge the Working Groups to find new and better ways of looking at the issues facing the industry.

Building sustainable communities is another ongoing OSLI project. OSLI is working with indigenous communities on new approaches to
In 2009, the OSLI companies collectively planted approximately 170,000 trees on reclaimed drilling pads. The Faster Forests initiative has now planted more than 1.6 million trees.
The Oil Sands Leadership Initiative

OSLI also uses a geospatial database/modelling system. This system is called Landscape Ecological Assessment and Planning (LEAP) and it is used to understand how today’s reclamation efforts will affect future forests and wildlife habitat. The database includes public data and additional data provided by OSLI companies, such as types of vegetation, age of vegetation, human-generated footprint and wildlife areas. LEAP is used to plan the Faster Forests initiative and winter wetland planting.

OSLI is also investigating alternative well configurations to improve the effectiveness of SAGD with field tests planned in 2013.

Other initiatives

Environmental initiatives include land stewardship. This means all OSLI companies aim to return disturbed land to as close to a natural state as possible. For example, Suncor is planning to turn former oil sands land into productive mixed wood forests and a wetland. In 2012, over 600,000 trees and shrubs were planted onsite.

The Faster Forests initiative means that since inception and up to 2012, OSLI companies have planted more than 1,600,000 trees. An innovative approach was used to condition seedlings in subfreezing temperatures. Nine hundred black spruce trees were planted in wetlands that are usually inaccessible during the summer season. Monitoring of this project shows an outstanding 90% survival rate for these trees after one year. Through innovation challenges and dedicated workshops, OSLI has also played a strong coordinating role to address caribou population sustainability in Alberta.

OSLI also uses a geospatial database/modelling system. This system is called Landscape Ecological Assessment and Planning (LEAP) and it is used to understand how today’s reclamation efforts will affect future forests and wildlife habitat. The database includes public data and additional data provided by OSLI companies, such as types of vegetation, age of vegetation, human-generated footprint and wildlife areas. LEAP is used to plan the Faster Forests initiative and winter wetland planting.

A co-ordinated approach is being taken to reducing greenhouse gas emissions in the Canadian oil sands sector. Instead of duplicating efforts already being made by OSLI members, OSLI has identified new areas that needed addressing in a coherent manner, such as developing technologies to reduce energy consumption, and emissions from water processing and steam generation.

Technological advances are important too. OSLI’s Water Technology Development Centre is working to optimise water use by oil sands operators.

Dr Vincent Saubestre is Executive Director, Oil Sands Leadership Initiative, Canada
Heavy oil and extra heavy oil

By Georgia Lewis

Globally, the energy industry is rising to the challenges presented by the extraction and production of heavy and extra-heavy oil.

Heavy oil or extra heavy oil is broadly defined as any type of crude oil that does not flow easily. The use of the word “heavy” refers to its density and gravity, which is higher than light crude oil. It is generally accepted that heavy oil has an API gravity of less than 20°. Heavy oils have a higher viscosity than lighter crude oils and a heavier molecular composition.

The World Energy Council has defined “extra heavy oil” as crude oil with a gravity of less than 10° API. Most oil that falls under the “extra heavy oil” category is bitumen from oil sands (See Chapter X). According to the US Geological Survey: “Natural bitumen … shares the attributes of heavy oil but is yet more dense and viscous. Often bitumen in present as a solid and does not flow at ambient conditions.”

There are six main processes used for the refining of heavy oil. These can be used individually or in combination with each other, depending on the requirements and resources at any given operation.

**Visbreaking**

The heating of heavy oil residue to a high temperature. This cracks some of it to lighter components and, thus, the viscosity of the flow is also reduced. It is a relatively mild thermal cracking process and, as well as reducing viscosity, it also serves to reduce the quantity of cutting stock required for residue dilution so that it meets fuel oil specifications. This increases the yield from more valuable distillates which are directly con-

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Natural bitumen collected from the shore of the Dead Sea. Present as a solid, it must be refined to create useful products.
Heavy oil and extra heavy oil

Coke, far from just a byproduct, can be used to power the smelters used in metals production, as well as a variety of other applications.

verted by visbreaking or used as catalytic cracker feedstocks.

There are two types of visbreaker operations: coil furnace cracking and soaker cracking. Coil furnace cracking uses temperatures between 470°C and 500°C and reaction times of a few minutes. Care needs to be taken with visbreaking – if the operation is too severe, there is a risk that the resulting product can become unstable, filters can become plugged and sludge forms during storage and use.

Soaker cracking, meanwhile, uses lower temperatures – between 430°C and 450°C – and longer reaction times. This method uses less energy than coil furnace cracking and also involves longer run times before operations have to shut down in order to remove coke from furnace tubes. However, soaker drum cleaning is difficult and time-consuming.

The coker tower at Suncor’s oil sands plant in Fort McMurray, Alberta.
Heavy oil and extra heavy oil

In the reactor, the feed is thermally cracked to produce a range of liquid products and coke. Bed coke is transferred from the reactor to the heater via a coke transfer line and hot coke from the heater is circulated back to the reactor to supply the heat required to maintain the reactor temperature. Excess coke is sent to the gasifier where the coke reacts with air and steam to produce a clean fuel gas. This gas can be used in boilers and furnaces. Around 97% of the coke generated by the reactor is consumed in the process.

**Flexicoking**
This is a process trademarked by ExxonMobil and first commercially applied in 1976 as an extension of its Fluid Coking process, which it pioneered in 1954. It is a continuous fluid bed technology that thermally converts heavy and extra heavy oils into lighter products. It is an integrated process that almost entirely eliminates the production of petroleum coke while also providing an economical fuel for refinery furnaces and boilers.

In the Flexicoking process, the feed enters a scrubber at 565°C for integrated direct contact heat exchange with reactor overhead effluent vapours. The scrubber condenses higher boiling hydrocarbons in the reactor’s effluent, usually at temperatures above 525°C. These are recycled along with the fresh feed for the reactor. The lighter overhead vapours are sent to conventional fractionation.

Coke falls from the bottom of the coking drum to be collected for reclamation and storage.

**Delayed coking**
This is a process whereby heavier crude oil fractions can be thermally decomposed under conditions of elevated temperatures and pressure. This produces a mixture of lighter oils and petroleum coke. The light oils can then be refined further to meet the requirements of different pro-
Whether used to create steam to aid in the extraction of oil sands as here, or in any of the various refining processes, vast quantities of heat are needed to create useful products from heavy oil.
Heavy oil and extra heavy oil

products and the coke can be used either as fuel or in other applications, such as the manufacture of aluminium or steel.

The set-up of a delayed coking unit can vary in size. Some have a single pair of coke drums and one feedstock furnace, but larger units may have as many as four pairs of drums as well as a furnace for each pair.

Residual oil from a vacuum distillation unit is pumped along the bottom of a distillation column (called the main fractionator). From there, it is pumped along with injected steam, into a furnace and heated to a temperature of around 480°C. Thermal cracking starts in the pipe between the furnace and the coke drums and finishes in the coke drum that is on-stream. The steam helps to reduce the deposition of coke within the furnace tubes. Some of the hot vapours produced are recycled back into the furnace as well as hot residual oil from the bottom of the fractionator.

When cracking takes place in the drum, gas oil and lighter components are generated in the vapour phase and are separated from liquid and solids. The drum effluent is mostly vapour along with some liquid or solid entrainment and these are directed to the main fractionator for further separation.

Any solid coke that is produced remains in the coke drum in a porous structure that allows flow through the pores. The time it takes for the coke drum to fill varies, but it usually between 16 and 24 hours.

Once the drum is full of solid coke, the hot mixture from the furnace is switched to the second drum in the pair. While this drum is filling, the full drum is steamed out to reduce the hydrocarbon content of the coke and then drenched with cooling water. Then, the top and bottom heads of the full coke drum are removed and the solid coke is cut away from the drum using a high-pressure water nozzle. From here, it falls into a pit, pad or sluiceway for reclamation to storage.

**Hydrocracking**

Hydrocracking is a versatile refining process for converting heavy oil components into naphtha, kerosene, jet fuel, diesel oil and high-quality lubricating oils. This is done through catalytic reactions under a high-temperature, high-pressure hydrogen conditions.

In a hydrocracking plant, when the heavy oil is passed on to the catalyst under these conditions, the impurities are removed through a combination of cracking, hydrogenation, isomerisation, desulphurisation and other chemical reactions.

There are different types of advanced process technologies which have been developed and applied to the design of hydrocracking plants. The flow schemes for such plants can be categorised into single-stage reaction systems and two-stage reaction systems.

In general, the single-stage reactor system is used for producing kerosene and diesel oil in a cost-effective manner, while the two-stage reactor system is used for cracking the feedstock oil completely so as to produce middle distillate oils. The single-stage reactor can be further integrated into the complete conversion system by recirculating the unconverted oil.

**Partial oxidation**

The main advantage of refining heavy oils by partial oxidation, instead of steam reforming, is that this method can operate on any type of hydrocarbon feed. No desulphurisation is needed before the partial oxidation step, as is the case in hydrocracking, for example. However, the main disadvantage is that the operator must provide a supply of 95% pure oxygen which increases plant investment and operating costs.

Partial oxidation is carried out by injecting the preheated oil and steam through a specially designed burner into a closed combustion vessel. In here, oxygen is added at around 1,290°C to create a reaction – the fuel-air mixture is partially
Unconventional Oil

Heavy oil and extra heavy oil

The process is also known as “solvent desasphalting.” It is a process that has been used for more than 50 years to separate heavy fractions of crude oil. The earliest solvent desasphalting applications used propane solvent to extract lubricating oil stock from vacuum residue. Over the decades, the process has been extended to the preparation of catalytic cracking feeds, hydrocracking feeds, hydro-desulphuriser feeds and asphalts.

Various hydrocarbons can be used for this process. Each hydrocarbon solvent is specifically designed to ensure the most economic process for each refinery. For example, a solvent containing propane may be used for a low deasphalted yield operation, but a heavier hydrocarbon, such as hexane, may be used to extract a high deasphalted oil yield from heavy vacuum residue feedstock.

Georgia Lewis is the Deputy Editor of International Systems and Communications.
EHO and bitumen require twice the amount of hydrogen as light crude oils to create fuel products. This is a strong motivation to develop lower-cost hydrogen generation in the places where these resources are abundant. AICISE includes an effort to develop in-situ production from residual oil and fractions of the recovered in-situ upgraded crude oil.

Other challenges faced by operators who favour in-situ upgrading include regulating temperature and pressure, but this can be alleviated by using hydrogen- and environment-adaptable catalysts.

Integrated field upgrading

In the mid-1990s, the Venezuelan oil industry was already considering the integration of partial field upgrading with either full upgrading or refining. The field upgrading targeted the replacement of diluents usually needed at the remote areas of production to transport to EHO or bitumen to large upgrading facilities. Extensive work was then deployed to develop complementary approaches to produce field upgrading at low cost, thus reducing the dependence on diluents.

Aquaconversion, a process that uses steam and an additive to extend visbreaking/thermal cracking levels of upgrading was the focus of this effort. This development was complemented by the integration of the field upgrading facilities to either hydroprocessing or delayed coking, bringing the moderately field-upgraded oil to more competitive quality levels. Integration has to be strategically assumed throughout oil corporations to fully assess the advantages of field upgrading.

The accentuated depletion of conventional oils makes more evident the limitations that the use of diluents has for carrying extra heavy oils (EHO) and bitumen to processing facilities. An alternative to dilution is field upgrading which involves an increased level of operations at production sites. With the deployment in Canada of thermal in-situ bitumen production technologies, such as steam-assisted gravity drainage (SAGD, see also page 31), a different engineering approach to that used in conventional oil exploitation is resulting.

The Alberta Ingenuity Centre for In-Situ Energy (AICISE) at the University of Calgary researches a wide range of novel hybrid processes to create effective in-reservoir processing elements, working closely with industry to achieve this.

This centre is creating a versatile range of small pilot plants to test hybrid processes at the conception stage. They have the potential to upgrade petroleum in-situ with reduced needs of energy introduction into the reservoir while selectively transforming contaminants into harmless products.

In-situ upgrading

The lessons learned from close to three decades of experience in EHO upgrading have made poss-
ible new ideas to accentuate the capture of synergies via integration activities for developing unconventional oils. This has taken place in parallel with the progression towards the new generation of nano catalysts for this purpose. In a technology-driven, varied and stimulating environment, such as the one existing in the oil sands of Alberta, Canada, such developments have taken place.

With the deployment of thermal in-situ bitumen production techniques, such as Steam Assisted Gravity Drainage (SAGD), a different engineering approach to the conventional oil exploitation was the result. SAGD allows the development of a relatively confined liquid and gas chamber along the length of the production wells. This chamber could be used as a reactor for in-situ upgrading processes or as a complement to field upgrading, resulting in environmentally and economically sound options.

Additionally, temperature levels in the reservoir can be increased with existing new technologies, such as the deployment of heating elements. This has been successfully tried by a number of companies. Expectations of moderate-to-medium upgrading of the crude oil in-situ are rising as a result. Efficient hybrid recovery processes can be quickly conceived and implemented via the joint efforts of multidisciplinary research teams working with industry.

**Hydrogen for in-situ and field upgrading**

The hydrogen demand created by upgrading EHO and bitumen, as well as shale oil, is the prime motivator for cost-effective hydrogen generation. AICISE includes a project to produce in-situ hydrogen from residual fractions of the in-situ upgraded crude oil.

A non-in-situ initiative has also been developed by the Catalysis for Bitumen Upgrading group at the Schulich School of Engineering at the University of Calgary to generate hydrogen in the context of a moderate low cost field upgrading. This development is based on the fundamental idea that only a fraction of heavy molecules, most of them recognised as asphaltene but many within the range of resins, are really at the basis of alienating the performance of EHO and bitumen upgrading and refining.

*Dr Pedro Pereira-Almao and Dr Stephen Larter are both professors at the University of Calgary School of Engineering.*
Case study: An integrated approach to in-situ upgrading

Transporting unrefined heavy oil by pipeline is problematic. Using SAGD to lower viscosity in combination with in-situ upgrading can greatly aid the process.
Case study: An integrated approach to in-situ upgrading
Case study: Residue decarbonisation technology for heavy oil

By Jifeng Liang and Yuzhen Zhang

CNOOC has developed a new method to upgrade heavy oil in an era where environmental protection is increasingly important.

Because of increased production of heavy crude oil and increasingly strict laws on environmental protection, new technologies for production are being developed.

Since the 1990s, there has been great progress made in delayed coking, visbreaking and solvent deasphalting, but these methods are not perfect. For example, delayed coking is a heat treatment with poor selectivity and the solvent deasphalting process is difficult in wholesale application.

In response to this challenge, the Heavy Oil Utilisation Research Centre (HOURC) at the China National Offshore Oil Company (CNOOC) has developed a new method – Residue Decarbonisation Combination Process (RDCP), which it has trademarked. RDCP is an evolutionary process which aims at improving yields and realising the wholesale application of the carbon-enriched components of heavy oil. In short, RDCP is simple in operation and low in equipment and operating costs. It also has good reaction selectivity and easy control and can improve the structure and character of the final product.

RDCP uses a self-catalysed reactor and, when used in combination with the solvent deasphalting process, both atmospheric residue and vacuum residue can be processed. To start with, residue feedstock is introduced into a low-pressure non-cooking reactor at a moderate temperature. Here, the large carbon chains are split into smaller molecules. Then the product is distilled and light cuts are removed. Next, the heavy liquid phase is sent to a solvent desasphalter where the extractable residue is separated and purified from the asphaltenes. The solvent is then recovered and deasphalting oil is blended with the extracted light cuts.

As well as excellent yields, this process results in products with a lower density and lower molecular weight than the feedstock. Carbon residue, calcium, sodium and nickel content are also reduced.

Jifeng Liang and Yuzhen Zhang are engineers for China Offshore Oil & Gas Development & Utilization Company.
Case study: A new process for heavy oil upgrading

By Alberto Delbianco, Salvatore Meli and Lorenzo Tagliabue, Nicoletta Panariti

While CNOOC has developed RDCP, Eni has pioneered a new technology to get the most out of every barrel of heavy oil.

Eni Slurry Technology (EST) was developed by Eni’s Exploration and Production division to innovate in the field of residue conversion and unconventional oil upgrading, with work starting on the project in the 1990s. Eni tested the new technology at the Taranto Refinery and operations started in 2005. EST allows the total conversion of the heaviest fraction of the barrel into useful products, mainly transportation fuels, with a major impact on the economic and environmental valorisation of hydrocarbon resources.

The benefit of the EST upgrading process is that it avoids the production of residual by-products such as petroleum coke and heavy fuel. It is a novel hydrocracking process that is particularly well suited for the total conversion to distillates of a variety of black oil materials, such as conventional vacuum residues, visbroken and thermal tars and residues from unconventional oils.

Today’s world refining industry still produces such by-products at an average level of around 15 to 20% of the crude oil feedstock. This material has long been used for applications as diverse as generating electricity and powering ships but, in the future, the tendency is towards the use of more environmentally acceptable fuels (those with less sulphur, less metals and possibly a higher hydrogen content, such as natural gas). On the other hand, as a cogeneration feedstock in integrated gasification combined cycle applications, high sulphur fuel oil must compete with low-price fuels, such as pet-coke and coal. Bitumens and extra heavy oils constitute the largest component of unconventional resources that we can expect to add to the conventional ones in the coming decades. This is the scenario in which Eni developed EST.

EST employs nano-sized hydrogenation catalysts and an original process scheme which allows complete feedstock conversion to valuable distillates, or to upgrade to synthetic crude oil with an API gravity gain of more than 20°. From the technological point of view, EST can be classified as a hydrocracking process, while the peculiar characteristics include the use of dispersed catalysts, an original process scheme for the catalyst handling that allows for almost total feedstock conversion as well as high upgrading performance.

The heart of the process is a slurry reactor in which the heavy feed is hydrocracked to to light products in the presence of thousands of parts-per-million of nano-sized catalysts. The catalysts are molybdenum-based. Molybdenum is a Group 6 chemical element that does not occur naturally as a free metal on Earth but rather in various states of oxidation in minerals.

The feedstock conversion is initiated thermally, breaking bonds and generating free radicals that are quenched by the hydrogen uptake reactions. This prevents the free radical recombination that could evolve to coke formation. The upgraded oil is withdrawn from the reactor and sent to a separation system to recover gas, naphtha, middle and vacuum distillates, while the unconverted
Case study: A new process for heavy oil upgrading

material, as well as the dispersed catalyst, are recycled back to the reactor.

Depending on the feedstock, the best process severity (reaction time and temperature) is selected in order to generate a residue at the limit of stability. This avoids the phenomenon of asphaltene precipitation which can generate coke and foul the process equipments.

The operation of recycling and blending the partially converted residue with an aromatic stream, such as the fresh feed, allows the recycle stream to recover stability so it can be reprocessed to achieve almost total conversion. After repeated cycles, the system reaches a sort of “steady state” situation so that the net result is the total conversion of feedstock to valuable products. In this way, EST can process heavy black oil materials assuring very high conversion to distillates without the generation of by-product, such as coke or heavy fuel oil.

*Alberto Delbianco, Salvatore Meli, Lorenzo Tagliabue and Nicoletta Panariti are engineers for Eni Divisione E&P.*
Gas-to-liquids

By Mark Blacklock

The gas-to-liquids (GTL) process offers a means of extracting greater value from an important resource.

Today’s GTL business draws on the pioneering work on synthetic fuels carried out by Franz Fischer and Hans Tropsch in Germany in the 1920s. They developed a process to turn gasified coal into liquids, and gave their names to the generic term Fischer-Tropsch (F-T) synthesis. However, Germany’s synthetic fuel production during World War II (which reached a peak of 50% of consumption in 1943) was largely based on hydrogenation with F-T production accounting for about 8% at the peak. It was South Africa which took the lead in developing large-scale F-T liquefaction plants after the war, initially using coal as a feedstock and later natural gas as well.

The original development of synthetic fuels was subsidised for strategic reasons; Germany and South Africa had large coal reserves but had to import oil. The challenge of subsequent R&D was to make synthetic fuel production commercially viable, and a number of proprietary technologies using F-T synthesis have been developed.

The basic process (see box) sees methane converted to carbon monoxide and hydrogen (syngas) for processing in a reactor to produce paraffinic waxes which can then be refined. The various proprietary technologies use different combinations of catalysts, reactor types and process conditions. The production phase of GTL uses more energy and thus entails higher emissions of greenhouse gases compared to a standard refinery, but the end products are cleaner.

The main product of a typical GTL plant is automotive diesel with virtually no sulphur or aromatics and a high cetane number. High-quality naphtha for petrochemical feedstock, kerosene for blending into jet fuel, normal paraffin and base oils for top-tier lubricants are also produced.

Monetising gas

GTL is a means of monetising gas resources that are abundant, undervalued or wasted by flaring.

A barrel of oil has roughly six times the energy of a million Btu (mmBtu) of gas. Oil has traditionally traded at a premium to gas given the ease of refining it to produce a range of products, but this premium has increased in some markets. At the time of the 19th World Petroleum Congress in 2008, for example, the oil price of $147/b and the US Henry Hub price for gas of $13/mmBtu meant the oil premium was 100%. By the time of the 20th WPC in 2011, the premium had risen to 500%, although it has since dipped slightly. At press time the Henry Hub price of $3.5/mmBtu gave a US oil premium of 488%.

Unconventional oil has come a long way since Professor Franz Fischer and Dr Hans Tropsch first developed their eponymous GTL process in the 1920s.
It is the flood of unconventional gas which has driven US prices down and is now driving interest in developing GTL plants. Sasol is moving ahead with the front-end engineering and design (FEED) stage of Westlake GTL in Louisiana and is also looking at a GTL plant in western Canada. Both would use shale gas as a feedstock. Other companies are considering projects.

For countries with abundant conventional gas resources, GTL is a way of providing high-quality products to the domestic market as well as extracting greater value from exports. Qatar Airways, for example, fuels aircraft departing from its Doha base with a 50:50 blend of locally-produced GTL kerosene and conventional jet fuel. The resulting GTL jet fuel is not only cleaner but has a higher concentration of energy and weighs less than conventional jet fuel.

Flaring gas associated with oil production is polluting and wasteful. Nigeria is one of the members of the World Bank-led Global Gas Flaring Reduction (GGFR) public-private partnership, and the Escravos GTL plant built by Chevron and the Nigerian National Petroleum Company will help the country eliminate flaring.

Brazil also wants to avoid flaring associated gas. For its offshore oil fields Petrobras is evaluating a project to include a small GTL plant on floating, production, storage and offloading (FPSO) vessels. This would produce a syncrude which would then be shipped with the main crude production to be refined elsewhere.

**GTL plants around the world**
The first large-scale plants using gas as a feedstock were commissioned in 1992 by Mossgas (now part of Petro SA) in Mossel Bay, South Africa (using

Petro SA was the first to develop a commercial scale GTL plant in Mossel Bay, South Africa.
Sasol’s advanced synthol process), and in 1993 by a Shell-led consortium in Bintulu, Malaysia (using Shell’s middle distillate synthesis – MDS). The Malaysian plant suffered an explosion in its air separation unit in December 1997 and was closed until May 2000, but this was caused by an accumulation of air-borne contaminants from forest fires and was not related to the GTL technology.

Oryx in Ras Laffan, Qatar was the next GTL plant and uses the slurry phase distillate (SPD) process developed by Sasol at a test plant in Sasolburg. Oryx shipped its first product in April 2007 but a higher than design level of fine material in the paraffinic wax initially constrained output, and it took several years to resolve the problems and achieve the intended output of 32,400 b/d. Oryx is now working on expanding capacity to 35,000 b/d through debottlenecking.

In Nigeria, the problems of building Escravos GTL in the Niger Delta caused long delays and cost over-runs. The plant was originally expected to cost $1.7 billion and be in service by 2008. The cost is now $9.5 billion and it is due to start operations in late 2013. This is over six times the cost of the similarly-sized Oryx plant (which was built under a fixed-price contract signed before construction costs in the petroleum industry escalated) but it will still be profitable at current oil prices. Escravos will use SPD.

However, the largest GTL plant, Pearl in Ras Laffan, Qatar, was built on time and budget. The first product was shipped in June 2011 and full
output was achieved in mid-2012. Pearl is an integrated project and its $19 billion cost covered the upstream as well as the downstream development. The project produces 120,000 b/d of upstream products (condensate, LPG and ethane), while the GTL plant has two 70,000 b/d trains and uses MDS with improved catalysts based on experience from the Bintulu plant.

**GTL projects**

Looking ahead, GTL plants using SPD in Louisiana, USA and Shurtan, Uzbekistan are at the FEED stage, while other large-scale projects are being evaluated in North America. And now that Pearl is in full operation, Shell is considering its future GTL options.

MDS and SPD are the two principal proprietary F-T technologies in commercial operation; others are on verge of commercialisation.

One is GTL.F1, a low temperature process using a cobalt-based catalyst in a slurry bubble column reactor. This was developed by Petro SA, Lurgi and Statoil in a 1,000 b/d semi-commercial unit at Mossel Bay. Statoil has since withdrawn and the remaining two partners are looking at opportunities for GTL.F1 in a number of markets with a focus on Mozambique.

For small-scale applications CompactGTL and Velocys have developed processes using mini- and microchannel technology and proprietary catalysts with steam methane reforming (SMR) to produce the syngas. Petrobras is working with both companies. The Brazilian NOC is keen to avoid flaring associated gas when developing offshore oil fields and aims to include a modular GTL plant on floating, production, storage and off-loading (FPSO) vessels. This would produce a syncrude for shipping with the main crude pro-
Gas-to-liquids

Production to be refined elsewhere. The capacity of each module would be 200 b/d and the overall capacity of the plant would be adjusted to match the declining flow of associated gas throughout the life of the oilfield by removing modules for refurbishment and re-deployment elsewhere.

CompactGTL has proved its technology in a demonstration plant at the Petrobras research centre in Aracaju, while a trial of the Velocys technology is underway at the Petrobras refinery in Fortaleza. Both companies are looking at other on- and offshore applications with a range of companies.

CompactGTL has worked on studies with Gazprom and Total, while the Velocys technology has been selected for proposed GTL plants in Pennsylvania and Ohio, USA, a biomass-to-liquids (BTL) plant in Oregon and a BTL plant in the UK called GreenSky London. Solena Fuels is working with British Airways on the latter project to produce 1,100 b/d of jet fuel and 1,100 of diesel and naphtha. It is in FEED with a targeted start-up in 2015.

Meanwhile, the Russian company Infra Technology claims significant productivity and catalyst performance benefits from the proprietary process it has developed to produce light synthetic oil and is working with Gazprom on a 100 b/d pilot plant.

**Growing importance**

By 2014, GTL production will exceed 250,000 b/d. While this is still a small proportion of the overall market for refined petroleum products, a high oil price and premium over gas mean the sector is set to grow in importance.

Mark Blacklock is the Editor-in-Chief of International Systems and Communications.

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**Processing natural gas**

After raw natural gas has been treated, there are three main operations in a gas-to-liquids plant. Firstly, synthesis gas (syngas) is produced. This is typically a combination of hydrogen and carbon monoxide in a ratio of 2:1, and four alternative methods are used:

1. **Fluidised bed processes**, in which syngas is passed rapidly at high temperatures through a catalyst bed, such as the Sasol advanced synthol process. This uses an iron-based catalyst. It has been superseded by SPD in the international market.
2. **Slurry processes**, in which syngas is reacted in a slurry with a catalyst and molten wax (produced in the reactor), such as the Sasol slurry phase distillate (SPD) low-temperature process. This uses a cobalt-based catalyst.
3. **Fixed bed processes**, where the syngas flows through tubes containing catalyst, such as Shell middle distillate synthesis (MDS). This uses a cobalt-based catalyst.

The synthetic crude is then converted into marketable petroleum products using conventional petrochemical upgrading processes, depending on the final slate of products required by the plant operator.
Both plants have been based on the results of an ongoing, evolutionary process involving research and development (R&D), pilot plant testing and the use of experiences gained from plant operation. This is a process that was initiated back in 1973 at Shell’s Amsterdam laboratory. In 1983, a pilot plant in Amsterdam was opened and in 1993, a plant opened in Bintulu, Malaysia. In 2010, construction on Qatar’s $19 billion Pearl GTL plant was completed; it opened in 2011 and went into full production in 2012.

This evolutionary process has not ended with Pearl GTL and Shell continues to invest in the further development of its GTL technology through continued basic R&D, pilot and demo plant testing, as well as drawing on the experiences gained in designing and operating Pearl GTL.

The areas of R&D are broad – gasification, gas treating, FT synthesis catalyst, hydroconversion, process integration, utilities, GTL products, engineering and new leads. The aim of this extensive work is to improve production, carbon efficiency, thermal efficiency, reliability, product slate, operating costs and capital costs. There are now GTL R&D facilities in Amsterdam, Bintulu and Doha, the capital of Qatar. More than $500 million has been invested in R&D by Shell, 3,500 patents have been filed and 80-100 people are employed.

The Pearl GTL project, located in the Ras Laffan Industrial City, Qatar, represents the second generation of Shell’s proprietary GTL technology. Shell’s middle distillate synthesis (MDS) plant in Bintulu, Malaysia, which started in 1993, represents the first generation of this technology as deployed on a commercial scale.

The Pearl GTL plant has often been described as one of the world’s largest, most complex and challenging energy projects.

Shell implemented the lessons they had learned in developing GTL technology in Bintulu, Malaysia (above) when moving to the second generation Pearl project in Qatar.
Case study: Shell’s Evolution in GTL Technology

Shell’s GTL synthesis catalyst evolution is an example of the company’s ongoing commitment to R&D. In the late 1980s, the catalyst was designed for the Bintulu plant and then applied in Bintulu on a retrofit basis from 2000. This led to the design of the catalyst for Qatar’s Pearl GTL plant which can also be retrofitted. The catalysts have steadily improved so that multitubular reactors are now part of Shell’s integrated GTL complexes. There is also the potential to retrofit a third generation catalyst at Pearl GTL, to expand the plant, to further expand production, and to optimise and extend the production slate.

Synthesis catalyst evolution involves many parties. At the laboratory/pilot plant stage, a mastery of fundamental surface sciences is important as well as the understanding and modelling of reaction kinetics, diffusion and deactivation mechanisms. At this stage, much testing takes place including testing of improved formulations, catalyst pellet sizes and shapes, operating procedures and samples of spent catalysts. Derisking innovations through dedicated efforts is another part of this stage.

Shell also worked with suppliers to optimise the raw material of catalysts, with catalyst manufacturers to improve manufacturing techniques.
and procedures and with specialist contractors to improve catalyst loading techniques. The Amsterdam-based lead researchers then worked with the Bintulu and Pearl GTL plants to make improvements to regeneration and activation procedures, operational procedures for startup, shutdown and upsets and overall catalyst management strategy.

The Bintulu project has contributed enormously to the Shell GTL evolution with many lessons learned, an estimated 3,000+ that can be transferred to other projects.

In terms of syngas manufacturing, Shell learnt how to upscale gasifiers, made modifications to burners, used suitable construction materials in critical hot parts of the facility, improved process control of parallel units and developed ways to treat syngas to more stringent specification. With synthesis, the Bintulu plant is an example of how to manage industrial scale synthesis catalyst performance, improve catalyst regeneration and loading, develop operational procedures for upset and retrofit more active catalysts. At the productions work-up stage, Bintulu has become an example of how to manage hydrocracking catalyst performance. Furthermore, new products have been developed and product specifications have been adapted to meet market requirements.

As well as advances in the production of GTL products, the Shell experience in Amsterdam, Bintulu and Qatar has helped to create a rigorous risk management system. A web-based system tracks 300 active risks and an assurance plan based on the risk profile has been set up.

The next generation of Shell GTL technology includes a third-generation catalyst, commitment to a lower CO₂ footprint and higher efficiency. Less equipment, steel and piping will be used and heat integration will be more advanced.

Managing technology in a mega-project, such as the development of Pearl GTL, is a challenge but Shell has five principles for such undertakings.

- Creativity is welcome – and necessary – but innovation is “perspiration rather than inspiration”.
- For a mega-project, a highly structured development process is required.
- A “key investigation” process is essential during front-end development.
- Risk profiling with a dedicated assurance process is always applied.
- A fully integrated GTL project needs all options evaluated with tools that reflect true integrated project economics.

Niels Fabricus, Senior Technical Advisor, Qatar Shell.

R&D work continues at Shell’s GTL pilot plant in Amsterdam.
Achieving the goal of no harm to people is a leadership journey where safety forms a common value that binds people together and enables them to be moved to a position where there is a belief that we can work without having incidents. This is a daunting task but Shell addressed it and won a Gold award in the inaugural Qatar Oil and Gas Industry Safety Awards.

In view of the size of the project, and when considering typical oil and gas project industry injury statistics, the Pearl GTL project in Qatar was expected to experience a large number of fatalities during the construction phase. Clearly this was unacceptable so a mitigation plan was developed by Shell. An extensive lessons-learned process was initiated that led to the identification of five main focus areas (workers' welfare, training, communications, leadership and life-critical activities) and established the value of caring for people.

A set of commitments against each of these themes; commitments the company would make, and counterpart commitments for the contractors were developed and signed by the entire project leadership, including the contractor CEOs. The implementation of these commitments was reviewed every six months at the contractor CEO summits with additional measures taken as deemed necessary.

Excellent progress was made in implementing the commitments, but energising the leadership needed additional attention. To address this, a safety leadership programme was introduced which made safety personnel work at every level of the project (leaders, supervisors, workforce) and helped instil in everyone the belief that you can work without having incidents.

Taking care of everyone's physical and mental health, we were able to get people to believe they could work safely and want to follow rules to keep them safe, rather than just compliance.

The results showed a safety performance in 2010 where the Lost Time Incident frequency was one tenth that of the International Association of Oil and Gas Producers (OGP) average in 2009. Based on historical industry statistics, it was projected that during construction of the Pearl GTL plant, there could have been 25 predicted fatalities, 190 non-accidental deaths (NAD) and a NAD rate of 1.2 deaths/1,000 man years. Instead, there was just one construction fatality, 53 non-accidental deaths and a NAD rate of 0.33 deaths/1,000 man hours.

Also, there were no serious road accidents in 260 million kilometres driven and a significant increase in productivity. The economic benefits of safety during the construction phase of GTL developments cannot be underestimated. In the case of the multicultural workforce on the Pearl GTL plant, Shell learnt to engage with communities, different cultures and different nationalities. Improved worker welfare, such as quality accommodation, recreational events and ongoing support were all directly linked to better performance.

Robert Munster, Vice President (Health, Safety, Environment and Sustainable Development), Qatar Shell.
Liquids that have been obtained via the coal liquefaction process can potentially be used as fuels or feedstocks for a wide range of petrochemical products and fuels. These include ultra-clean petroleum and diesel, synthetic waxes, lubricants, stationary power generation, ultra-clean indoor cooking fuels, chemical feedstocks and alternative liquid fuels, such as methanol and dimethyl ether (DME).

This process was first used in the 19th century to provide fuel for indoor lighting. Coal liquefaction has a long history in countries such as Germany and South Africa where there is not a secure supply of crude oil.

South Africa has been producing CTL fuels since 1955 and has produced more than 700 million barrels of CTL fuels since the early 1980s. Around 30% of country’s petrol and gasoline needs are met from indigenous coal. Also, around 85% of the coal consumed in South Africa is used as either feedstock or to produce electricity. As well as using CTL fuels in road vehicles, South African energy company Sasol has also approved CTL fuels for use in commercial jets.

For countries with large reserves of coal still remaining, there can be many advantages to using these reserves for CTL production. On a domestic level, this can reduce the reliance on imported fuels, provide affordable energy and create employment. For countries with coal reserves, CTL technology helps achieve a more balanced energy mix.

The coal-to-liquids (CTL) process is generally more expensive than refining crude oil but it can be cost-effective if crude oil is in limited supply, unavailable or the supply has been disrupted. Coal liquefaction can be a more efficient process if it is combined with electricity production as this utilises some of the heat that would otherwise be wasted. Unsurprisingly, interest in constructing CTL plants generally increases when oil prices are high and different markets are worried about the cost of importing oil, while they are less favoured when the oil price falls.

**Direct and indirect liquefaction**

CTL processing can be achieved via either direct or indirect liquefaction.

Direct coal liquefaction (DCL) works by dissolving coal in a solvent at a high temperature and pressure. It is an efficient process but the resultant liquid products then require further refining before they can be used as high-grade fuel.

The DCL process can take place as a one- or two-stage process. In the 1960s, single-stage DCL techniques were pioneered but these first-generation processes have now been largely superseded or abandoned. The single-stage processes attempted to convert coal to liquids with a single reaction stage, usually involving an integrated hydrotreating reactor.

In DCL, the coal is put in direct contact with the catalyst at very high temperatures (850°F/455°C) in the presence of additional hydrogen. This reaction takes place in the presence of a solvent. The solvent facilitates coal extraction. The solubilised products, which consist mainly of aromatic compounds, then may be upgraded by conventional petroleum refining techniques, such as hydrotreating.
Coal-to-liquids

Hans Tropsch in 1925 and it is still used today. Once the coal gas is filtered and processed, the carbon monoxide and hydrogen ratio is adjusted by the addition of water or carbon dioxide. This hot gas is passed over a catalyst, causing the carbon monoxide and hydrogen to condense into long hydrocarbon chains and water. These chains can be used as an alternative to oil products such as heating oil, kerosene and gasoline. The water, meanwhile, can be recycled and used as steam for the liquefaction process.

Pioneers in coal liquefaction technology development include American companies such as HRI, Exxon, Gulf Oil, Conoco, Chevron, Amoco, Lummus, Kerr-McGee and Consol; Germany’s Ruhrkohle; the UK’s British Coal Corporation; and Japan’s NEDO and Mitsubishi Heavy Industries.

### CTL in transportation

For markets in which vehicle ownership is on the rise, CTL can help make vehicle fuel more affordable, especially when oil prices are high. CTL, along with GTL and biomass-to-liquids (BTL) can all allow for greater diversification of liquid fuel supplies, which is a great boon to the transport sector.

When used for transportation fuels, gasoline and diesel from CTL can be accessed by consumers at existing filling station pumps through existing infra-

DCL processes are more efficient than ICL but a higher quality coal is required for best results. However, since the late 1980s, very few DCL programmes were continued with the exception of HTI, now called Headwater Inc, has developed a two-stage catalytic liquefaction process that was funded by the US Department of Energy. This technology was then licensed to China’s Shenhua Corporation in 2002 for the construction of a 20,000 bpd plant in Inner Mongolia that commenced demonstration testing in 2008 and has been operational ever since.

Indirect coal liquefaction (ICL) gasifies the coal to create a syngas, a mixture of carbon monoxide and hydrogen, and this syngas is condensed over a catalyst to produce high-grade, ultra-clean products.

There are two main stages to the indirect coal liquefaction (ICL) process – coal gasification and gas-to-liquid (GTL). During gasification, air and steam are added to raw coal and this is heated. The carbon in the coal reacts with oxygen and water to produce carbon monoxide, carbon dioxide, hydrogen and methane. The CO\(_2\) is waste and other gases can be burnt or processed further.

The second stage for indirect liquefaction is the Fischer-Tropsch process. This is an indirect liquefaction process developed by Franz Fischer and Hans Tropsch in 1925 and it is still used today. Once the coal gas is filtered and processed, the carbon monoxide and hydrogen ratio is adjusted by the addition of water or carbon dioxide. This hot gas is passed over a catalyst, causing the carbon monoxide and hydrogen to condense into long hydrocarbon chains and water. These chains can be used as an alternative to oil products such as heating oil, kerosene and gasoline. The water, meanwhile, can be recycled and used as steam for the liquefaction process.

Aiming to diversify the uses of its vast coal reserves, China has pioneered direct coal liquefaction with Shenhua’s Inner Mongolian CTL facility.
Unconventional Oil

Coal-to-liquids process is more CO₂-intensive than conventional oil refining but there are options available for the prevention or mitigation of emissions.

At CTL plants, CO₂ concerns can be addressed using cost-effective carbon capture and storage (CCS) techniques. At plants where both coal and biomass are processed and CCS techniques are used, greenhouse gas emissions over an entire fuel cycle may be as low as one-fifth of those from fuels provided by conventional oil.

CTL has also been mooted as a bridging fuel towards a future where hydrogen fuels are far more prevalent. Using polygeneration – that is, the connecting of multiple types of energy plants at the one location – plants that produce CTL and other fuels could become more commonplace as different countries seek to achieve long-term energy security.

Georgia Lewis is Deputy Editor at International Systems and Communications

Environmental concerns

CTL production, like any process in which feedstock is converted to liquid fuels, is an energy-intensive exercise. Across the whole process, greenhouse gas emissions are an important consideration for producers and regulators. The CTL production process is more CO₂-intensive than conventional oil refining but there are options available for the prevention or mitigation of emissions.

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BHP Billiton’s Klipspruit Colliery. After almost 60 years’ experience in producing fuel via CTL, 30% of South African vehicles are run on fuel produced from local coal.
Glossary of terms

Above-ground processing  Used to extract and process shale oil, this involves the pyrolysis of oil shale in a retort vessel to produce shale-derived oil and processing this oil to produce feedstock.

API gravity  The American Petroleum Institute (API) determined a measure of how heavy or light a petroleum liquid is compared to water. If the API gravity is greater than 10°, it is lighter and floats on water. If it is less than 10°, it is heavier and sinks. Although, mathematically, API gravity has no units, it is still referred to as being in “degrees”. The API scale was devised so that most values would fall between 10 and 70 API gravity degrees.

Asphalt  A brown-black solid or semi-solid mixture of bitumens which are commonly used in roofing, paving and waterproofing. Derived from either native deposits or as a petroleum by-product.

Asphaltenes  Very large molecules that incorporate most of the sulphur and approximately 90% of the metals of heavy oil.

Bitumen  Any of the different mixtures of hydrocarbons, which present as tar. These are often found together with their non-metallic, naturally occurring derivatives, or they can be obtained as residues after refining processes have taken place.

Catalytic conversion  The catalytic (of or relating to a catalyst) oxidation of carbon monoxide and hydrocarbons, especially in automotive exhaust gas to carbon dioxide and water.

Catalytic reforming  Catalytic reforming is the chemical process which is used to convert low-octane petroleum refinery naphthas into high-octane liquid products. These products are called reformates and they are components of high-octane petrol.

Centipoise  Commonly abbreviated to cP, this is a centimetre-gram-second unit of viscosity equal to one-hundredth of a poise.

Coal-to-liquids (CTL)  The result of converting coal to a liquid fuel, a process known as coal liquefaction. This can be done via direct or indirect liquefaction.

Coke  High-carbon material produced as a result of coking.

Coking  The process of deriving petroleum coke, a carbonaceous solid, from petroleum using oil refinery coker units or other cracking processes.

Cracking  The breaking down of large molecules as part of the refining process.

Crude oil  A naturally occurring, unrefined petroleum product made up of hydrocarbon deposits. It can be refined to produce useful products, such as gasoline, diesel and different types of petrochemicals. The viscosity and colour of crude oil can vary, depending on its hydrocarbon composition.

Cyclic steam stimulation (CSS)  A three-stage process consisting of injection, soaking and production. Steam is injected into a well to heat the oil to a temperature where it can flow, this is then left to soak, usually for a few days, before it is produced out of the same well. This is done firstly by natural flow and then by artificial lift. Production decreases as the oil cools. Also known as the huff and puff method.

Derivative products  Heavy oil derivative products can be made in a number of different ways, using different methods of refining and upgrading. The number of steps involved to create a final product varies.

Diluent  A thinning agent made up of a mixture of organic compounds which contain lighter hydrocarbons.
**Distillation**  A method of physically separating mixtures in a boiling liquid mixture.

**Enhanced oil recovery (EOR)**  A generic term for techniques aimed at increasing the quantity of crude oil that can be extracted from a source. It is also known as improved oil recovery or tertiary recovery.

**Extra heavy oil**  The portion of heavy oil having an API gravity of less than 10°.

**Feedstock**  The raw material that is needed for some industrial processes.

**Fischer-Tropsch process**  A collection of chemical reactions that converts a mixture of carbon monoxide and hydrogen into liquid hydrocarbons. It was developed in 1925 in Germany by Franz Fischer and Hans Tropsch.

**Fossil fuel**  Hydrocarbons, primarily fuel oil, natural gas or coal, formed from the remains of dead plants and animals. The term is also often used to refer to hydrocarbon-containing natural resources that are not derived from animal or plant sources but are in finite supply.

**Fracking**  See Hydraulic fracturing.

**Fraction**  A component of a mixture that has been separated by a fractional process.

**Gas-to-liquids (GTL)**  A refinery process used to convert natural gas or other gaseous hydrocarbons into longer-chain hydrocarbons, such as gasoline or diesel.

**Greenhouse gas (GHG)**  Gases, either naturally occurring or man-made, which allow sunlight to enter the Earth’s atmosphere freely. These gases absorb infrared radiation and trap heat in the atmosphere.

**Heavy oil**  Asphaltic, dense, viscous oil with a low API gravity. It is chemically characterised by its content of asphaltenes. Although definitions vary, the upper limit for heavy oils has been set at 22° API gravity and a viscosity of less than 100cP.

**Huff and puff method**  See cyclic steam stimulation (CSS).

**Hydraulic fracturing**  The process of creating small fissures, or fractures, in underground formations to release oil or natural gas. It involves the use of high pressure truck-mounted pumps to push water, sand and chemical additives into a formation to create fractures. These fractures are propped open by the sand to allow the oil or natural gas to flow into the wellbore for collection at the surface.

**Hydrocarbon**  A broad term that refers to organic chemicals that are characterised by various carbon and hydrogen molecular structures.

**Hydrogen**  A flammable, colourless gas with the chemical symbol H and H2 as a molecule of gas. It is the lightest and most abundant element in the universe.

**Hydrogenation**  To treat or combine with, or expose to hydrogen. Shale oil is low in hydrogen so it needs to be hydrogenated as part of the process to make it commercially usable.

**Improved oil recovery**  See Enhanced oil recovery (EOR).

**In-situ**  A relatively new method used to extract bitumen from oil sand that is buried too deep beneath the surface to be mined with a truck and shovel. In-situ technology injects steam below the surface to separate the viscous bitumen from sand and then pumps it to the surface before upgrading. In-situ is Latin for “in place”.

**In-situ conversion process (ICP)**  This involves blocking off sections of an oil shale deposit using freeze walls, heating the oil shale via conduction. This releases the shale oil and gas from the rock whereby it can be pumped to the surface.

**Kerogen**  A solidified mixture of organic compounds. This mixture releases crude oil and natural gas when it is heated inside the Earth’s crust. It is found in shale deposits where it can be exploited as shale oil or shale gas.
Glossary

Kerogen oil  See Shale oil.

Light oil  Also known as “conventional oil”, light oil has an API gravity of at least 22° and a viscosity less than 100 cP.

Modified in-situ (MIS)  When a combination of in-situ and traditional mining methods are used.

Naphtha  Generally refers to a number of flammable liquid mixtures of hydrocarbons that boil in a certain range. It is a broad term which encompasses the lightest and most volatile fractions of the liquid hydrocarbons in petroleum. It is colourless to reddish-brown and can be used as a diluent.

Natural gas  A fossil fuel. Natural gas is a mixture of naturally occurring hydrocarbon gases and it is primarily used as a fuel and for making organic compounds. Deposits are found beneath the Earth's surface. Methane is the main component of natural gas but it also contains varying quantities of ethane, propane, butane and nitrogen.

Oil sands  Sand and rock material containing bitumen. The bitumen is extracted and processed using surface mining or in-situ processes.

Oil shale oil  See Shale oil.

Open cast  A surface mining technique of extracting rock or minerals from the ground by their removal from an open pit.

Overburden  The layer of soil, rocks and other organic material that sits on top of a deposit of oil sand.

Permeability  The property or condition of being permeable. Also refers to the rate of flow of a liquid or gas through porous material.

Petrochemicals  Any substance obtained from petroleum or natural gas.

Petroleum  A thick, flammable mixture of gaseous liquid and solid hydrocarbons occurring naturally beneath the Earth’s surface. The origins of petroleum are believed to come from accumulated remains of fossilised plants and animals. Petroleum can be separated into fractions including natural gas, gasoline, lubricating oils, naphtha, kerosene, paraffin wax and asphalt. It can also be used as raw material for a range of derivative products.

Petroleum coke  Often abbreviated to “pet coke” or “pet coke”, this is the carbonaceous solid derived from petroleum during a refining process.

Porosity  The state or property of being porous/having pores. Pores in rock allow for the passage of oil or gas.

Pyrolysis  The most common method for extracting oil from shale, this involves the heating of raw materials to convert the kerogen into shale oil vapours through decomposition. The vapours are then collected via distillation before being refined.

Reclamation  The process of restoring an area after surface mining activities are complete. The reclamation process includes maintaining air and water quality, minimising erosion, flooding and damage to wildlife and aquatic habitats. Often, the final step in the reclamation process is the replacement of topsoil and revegetation with appropriate plant species.

Refinery  An industrial plant where a crude substance, such as crude oil, natural gas or coal, is purified so it can then be turned into more useful products.

Room and Pillar (R&P)  A means of extracting oil or other natural resources from underground deposits by first cutting out rooms and then extracting from the pillars that have been created between them.

Sedimentary rock  Rock formed by the deposition and solidification of sediment, usually transported by water, ice in the form of glaciers or wind. These rocks are frequently deposited in layers.
Shale oil  An unconventional oil extracted from shale rock by processes such as pyrolysis, underground mining and surface mining. These techniques convert the organic matter within the rock (also known as kerogen) into synthetic oil. This oil can be used as a fuel or upgraded to meet refinery stock specifications by adding hydrogen and removing impurities. The products can be used for the same purposes as those which come from crude oil.

Solvent extraction  Methods for extracting shale oil by treating the shale with a solvent system of water and an alcohol at an elevated temperature.

Steam assisted gravity drainage (SAGD)  A technique to extract bitumen from oil sands by injecting steam into the reservoir before it flows by gravity to a second well and is pumped to the surface for processing.

Steam cracking  The high-temperature cracking of petroleum hydrocarbons in the presence of steam as part of the petroleum-refining process.

Strip mining  See Surface mining.

Surface mining  A broad term for mining in which soil and rock overlying the mineral deposit are removed. Surface mining techniques include strip mining, open-pit mining and mountaintop-removal mining.

Synthetic crude  A complex mixture of hydrocarbons that are somewhat similar to petroleum. These are obtained from oil sands, shale oil, synthesis gas or coal. Known as syncrude.

Synthesis gas  A mixture of carbon monoxide and hydrogen. This is mainly used in chemical synthesis to make hydrocarbons. Known as syngas.

Synthetic  Produced by synthesis, not of natural origin.

Tailings ponds  An engineered dam-and-dike system used by mines as a settling basin/storage solution for the mixture of water, sand, clay and residual oil that is left over after oil sands have been processed. Once this mixture is in the pond, the sand sinks to the bottom and the water from the uppermost three metres is recycled.

Tar sands  See Oil sands.

Tertiary recovery  See Enhanced oil recovery (EOR).

Thermal dissolution  A hydrogen-donor solvent refining process used for shale oil and coal liquefaction.

Toe-to-heel air injection (THAI)  An in-situ method of bitumen recovery in which air is continuously injected into the deposit to create a wave of combustion. This pushes recoverable and partly upgraded oil towards a production well or production portion of a well. The name comes from the initial design of the process – air gets injected at the end of the horizontal well (the “toe”) and the wave travels the length of the well to the other end (the “heel”).

Underground mining  A general term for the mining techniques which take place underground to extract shale oil, coal or other minerals from sedimentary rocks.

Unconventional oil  Petroleum that is produced or extracted using techniques other than the conventional oil well method.

Upgrading  The process in which heavy oil and bitumen (extra heavy oil) are converted into lighter, more usable crude oil by increasing the ratio of hydrogen to carbon. This is normally done by either coking or hydroprocessing.

Vacuum distillation unit  A distillation column that operates in a vacuum (where operating pressure is less than atmospheric pressure). Used in the production of oil sands.

Viscosity  The property of a fluid that resists the force tending to cause the fluid to flow, or the measure of the extent to which a fluid possesses this property.
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