

CONVENTIONAL AND NON CONVENTIONAL OIL SUPPLY TO 2030: A WORLD-WIDE ECONOMIC ANALYSIS BASED ON A MODELLING APPROACH¹

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Introduction

The global energy trend forecasts point out an increasing demand over the next decades, especially for electricity and automotive fuel. Over the next 25 years, the growing activity of the transport sector will involve increasing quantities of liquid fuels. On the supply side, the crude oil share in the total primary energy supply should remain to around 35% until 2030. Thus, the non conventional supply, coming from non-conventional oil (tar sands, extra-heavy oil and oil shale) as well as technologies transforming gas or coal to liquids should give a significant and necessary contribution to the global crude oil availability.

We have analysed the potential development of the conventional and the non conventional supply in a worldwide model which aims to satisfy the oil products demand until 2030. In this analysis, several geographical areas have been distinguished, to take into account the regional dimension of the supply and the demand. This paper is organised as follow: section 1 concerns the conventional supply, section 2 deals with the non-conventional supply, section 3 gives an overview of the modelling approach and, finally, the results are given in the last section.

1. The conventional supply

"Conventional supply" refers to world-wide crude oil production without considering bitumen, extra-heavy oil, oil shale, products from gas or Coal to liquids technologies. That supply is analysed in the section 2. Liquids from biomass are also excluded.

We have considered the crude conventional supply given by the IEA WEO 2006. The crude conventional supply, around 80 Mbb/d in 2006, should increase to about 98.7 Mbb/d in 2020 according to that document. This is, to our opinion, an optimistic point of view which implies a high level of oil price and large level of investments. The issue today is that with the high oil price, resource nationalism is coming back. That implies more difficulties for international companies to invest in foreign countries, at a moment where large investments are needed to develop additional production capacities to meet the international demand.

FSU conventional crude production on the 2006-2020 period should increase of around 34% and reach 16 Mbb/d. That increased is mainly allowed thanks to Kazakhstan and Russia. In Kazakhstan, the development of the giant Kashagan field will secure a production of 1.2 Mbb/d for a long time. The main issue today in Russia is the lack of investments mainly due to lack of transparency of the hydrocarbon legislation. However, on the long term, the production should increase given the importance of the reserves volumes.

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Middle East should see its production increase of about 46% between 2005 and 2020 and reach 37.2 Mbbl/d in 2020, mainly thanks to increase production in Saudi Arabia, Iraq and Kuwait. To reach those levels, the political situation in Iraq must be quickly stabilized to allow investments in production capacities. Thanks to the large oil reserves in the region, we can hope that in the long term, the production reaches the IEA WEO level.

Africa conventional production should reach 14.4 Mbbl/d in 2020 after a 31% increase. This is mainly due to Nigeria and Angola and in a smaller part to others west African countries like Congo. Thanks to the end of the American sanctions in Libya, the country can have a sustain high level of production, up to 2 Mbbl/d.

South America conventional production should increase of 54% and reach 9.6 Mbbl/d in 2020. That increase is mainly due to Brazil, Venezuela and to a smaller part from Ecuador. In Brazil, the increase mainly comes from deep offshore developments.

In North America, conventional crude production should also decline of around 8 % between 2006 and 2020 to reach 11.2 Mbbl/d. In USA, the production decline is slowed thanks to the deep offshore zone and natural gas liquids but the onshore production is inexorably declining. In Mexico, the decline of the important Cantarell field (1.5 Mbbl/d) should be partially offset by the development of the KU-Maloob-Zap complex. The country suffers from a lack of investments especially in exploration. Lots of uncertainties persist about the ability for Pemex to conduct alone the needed work.

In Asia, the conventional crude production should also decline of around 7% between 2006 and 2020 to reach 7 Mbbl/d. Indonesia and Australia show important decline of their conventional production. In China, the declining production in the traditional North and Songliao basins should be, for a short period of time, offset by the production coming from western basins.

European crude production is sharply declining. There seems to be no reason to expect a turnaround in the decline of the North sea given the maturity of the fields. Production could see some slowing in decline thanks to new field developments especially in Norwegian Northern North Sea. European liquids production should be around 3.6 Mbbl/d in 2020, which means a decline of 40% comparing to the 2006 level.

2. The non conventional supply

"Non-conventional supply" refers to the exploitation of the natural bitumen, the extra-heavy oil and the oil shale as well as products from technologies transforming gas or coal to liquids i.e. Coal to Liquids (CTL) and Gas to Liquids (GTL) technologies.

Extra-heavy oil and bitumen are heavier than water ($^{\circ}\text{API} < 10$) and the distinction between them is made on the in-situ viscosity level: smaller than 10 000 centipoises (cP) for extra-heavy oil and greater than 10 000 cP for natural bitumen, or tar sands or oil sands. Due to those specific properties, the exploitation of those resources implies specific methods to extract, transport and transform them into final products.

Oil shale are sedimentary rocks containing a high proportion of seaweed organic matter, which transformation is not complete: shale are rich in kerogen, which give them an energetic interest. The kerogen can be converted to synthetic oil or gas by processing.

2.1. Tar sands

The identified volumes in place of tar sands are estimated between 2 200 and 3 700 billions of barrels (Bbbl), the main part being located in Canada, where the resources are assessed between 1 600 and 2 500 Bbbl. Smaller volumes have been identified worldwide, mainly in Asia, Russia, Venezuela and USA. Recoverable volumes outside Canada are estimated between 90 and 130 Bbbl.

According to the Alberta Energy & Utilities Board (AEUB), current technologies allow to recover some 178 Bbbl of bitumen. With anticipated technologies, ultimate recoverable volume could be 300 Bbbl. About

20% (35 Bbbl) of the recoverable resources of bitumen are located at a shallow depth and can be exploited using mining technologies. 80% (140 Bbbl) require petroleum technologies for its exploitation.

Projects concerning bitumen exploitation are mainly located in Canada. Since 1967, there has been production from the oil sands of the Western Canada Sedimentary Basin, in Athabasca. Suncor was the first company to embark on mining production in 1967, followed by Syncrude in 1978. The first production based on in situ methods started in the early 1980s with an initial expansion driven by the high prices of oil during those years. Major actors in in situ bitumen production are Imperial Oil (Exxon Mobil affiliate), Canadian Natural Resources Ltd (CNRL) and EnCana.

2.1.1. Mining production projects

Around twenty percent of the recoverable resources of bitumen are located at a shallow depth (less than 100 m) in the Fort McMurray Oil Sands Area and can be exploited using mining technologies. This production method currently provides 61% of the Canadian bitumen production i.e. 627 000 bbl/d in 2005.

That kind of project is very capitalistic. Investment are estimated between 45 000 and 80 000 \$/bbl/d. Production scale is over 100 000 bbl/d and at this scale, installation of an upgrading units dedicated to the exploitation is commercially viable. In all the projects, the bitumen is upgraded on the production and sold in the form of synthetic crude oil, with an API degree between 29 and 36 and sulphur content between 0.1 and 0.2 %. Upgraders contain typically a coker and hydrotreatment units. It produces large amount of coke and a synthetic crude which can be transported to refineries where it is treated and transformed into petroleum products.

This activity is dominated today by two companies, Syncrude and Suncor who both are conducting major projects to increase their bitumen output. Shell Canada, under the Albian Sands Energy Company, is also producing oil sands by mining methods at Muskeg River since 2003. With the development of its Athabasca Oil Sands Project, Albian Sands Energy Company will become the second largest mining producer in 2015. Four others projects are under development. In 2015, they all should be running and the total production of synthetic crude oil from bitumen mining exploitation should reach about 1.9 Mbbl/d .

2.1.2. In situ production projects

Eighty percent of the recoverable resources of bitumen in Canada are located at a greater depth and must be exploited using in situ production technologies (i.e. recovery by petroleum methods). Due to the high viscosity of the bitumen, the fields must be exploited by using **steam injection**. About twenty projects, currently underway or being studied, are expected in the coming years. In 2005, in-situ production of bitumen in Canada was about 390 000 bbl/d. It could reach 1,320 Mbbl/d in 2015.

In-situ production projects are generally of a smaller scale than the mining ones and can not accommodate the cost of a dedicated upgrader. Investments are estimated between 13 000 and 25 000 \$/bbl/d. In quite all such projects, the bitumen is blended with a lighter, less viscous hydrocarbon (diluent) and sold as bitumen blend, with an API degree of 21 and sulphur content between 2 and 4 %. Diluent typically constitutes 24-50% of the bitumen blend. Only two projects include an on-site upgrading and produce SCO (Synthetic Crude oil) instead of bitumen blend: Firebag (Suncor) and Long Lake (Nexen/OPTI).

All together (mining or in-situ), more than 25 Canadian projects for the exploitation of tar sands and bitumen have been developed or are about to be developed. They will represent, if accomplished, a production of **2.1 Mbbl/d of synthetic crude and 1.06 Mbbl/d of bitumen blend in 2015**. In other words, the 2005 Canadian heavy oil and bitumen output should be multiplied by a factor of 3.

2.2. Extra-heavy oils

According to the United States Geological Survey (USGS), the worldwide extra heavy oil resources are estimated at around 1 350 Bbbl. About 90% of those resources are located in the Orinoco Belt in Venezuela, where they are evaluated at 1 200 Bbbl. It is estimated that 20% of resources in place in Venezuela is ultimately recoverable, which means about 240 Bbbl. At current technology and price, the recoverable volumes are estimated at about 3% - 36 millions of barrels (Mbbbl). Extra heavy oil has also been identified in other countries especially in Ecuador, Iran and Italy. Small amount have been identified in Russia but accurate and timely data are insufficient for making estimates.

Projects concerning extra-heavy oil are located in Venezuela, in the Orinoco Belt. No projects are reported in Russia concerning extra-heavy oil exploitation. The Orinoco Belt is the largest extra heavy oil deposit in the world, with an estimated 1 350 billion barrels of oil in place.

During the last ten years, joint-ventures (J.V.) involving major international oil companies have proposed or studied integrated projects to develop and exploit extra-heavy oil resources of the Orinoco Belt. Given the huge volumes of recoverable reserves, those JVs are contracted for 35 years and four extra-heavy oil projects are currently underway. They all include production by cold method, transportation of the heavy crude by pipeline through dilution to an upgrader on the Coast at San Jose. There, the crude is more or less upgraded depending on the project: two projects upgrade extra-heavy crude to a 26-32°API crude which can then be exported and used as feed in common refineries. In the two others, the crude is only partially upgraded and then exported to specific U.S. refineries dedicated to the upgrading of heavy oil. Capital intensity for the projects vary from 17 000 to 36 000 \$/bbl/d depending on the upgrading options.

The upgrader produces upgraded crude, which is exported, as well as coke and sulphur, also exported and it recovers the fluidisers added upstream. It is sent back to production plant (far from about 200 km) in a dedicated pipeline, to be reused for the same purpose. Recycling the diluent allows to lower operating costs, even if investment costs are higher as a return pipeline should be constructed.

The cold production method is the cheapest and the most environmental friendly one. Its disadvantage is that it allows the lowest recovery rate (5 to 10%), but the oil in place is so huge that the reserves are finally very important. The four projects are today producing at maximum rate, which means that the total output of synthetic crude is close to 600 000 bbl/d.

Concerning the future developments of Orinoco Belt, Petroleos de Venezuela (PDVSA) calls in its last strategic plan for the investment of about \$15 billions during 2006-2012 to increase production from the Orinoco extra-heavy oil belt to 1.2 millions bbl/d from the present level of 584 000 bbl/d. The first phase of the plan involves the quantification and certification of reserves. After this work, PDVSA hopes to enter negotiations with the third party companies to recover more than 20% of the oil in place of these areas.

2.3. Oil shale

Relatively little is known about many deposits of oil shale and much exploration drilling and analytical work still need to be done. The identified oil shale volumes in place are estimated at around 7 000 Billions of tonnes. Depending on information sources, the oil content of this oil shale resources is estimated between 2 600 and 4 400 Billions barrels. About 70% of those in-place resources is concentrated in the USA and 14% is located in Russia. Smaller volumes are also located in Zaire, Brazil and Italy. No data do exist concerning recovery ratio of the oil containing in shale. It hardly depends on the depth of the deposit and the exploitation process used.

Yet only few countries utilise this resource. Under the pressure of competition, oil shale extraction has ceased in Canada, Scotland, Sweden, France, Australia (where it restarted in 1999), Romania and South Africa, and has not taken off in the USA, Belarus, Jordan and Morocco.

Beginning of the 2000's, about 16 Mt/year of oil shale were extracted in 6 countries: Estonia Australia, Brazil, China, Germany and Russia. A small part was transformed into synthetic crude: 8000 b/d in Estonia and 1 600 b/d in China. Those volumes represent about 0.01% of the world total liquids production. Today, the biggest producer is Estonia, but since the country has entered into the European Community, it has been asked to stop using oil shale as direct feed for power plant. The last biggest oil shale development project was the Stuart project in Australia. It consisted in an open pit mine and surface retorting installations to produce 200 000 bbl/d of high quality products over more than 30 years with no production decline. That project has been postponed in 2004 for energetic yield and environmental costs questions.

Today there is no project aiming at a commercial development of oil shale. A commercial development of oil shale is highly conditioned by the validation of some production technologies today at a development stage and especially in-situ processes. Beginning of 2006, the US Mineral Management Services has awarded 5 companies 8 research and development acreages. 6 over the 8 projects concern in-situ exploitation technologies. That research will not lead to commercial development before 10 to 15 years. We have assumed that production should start at the earliest in the 2020's. The DOE/AEO 2006 forecast a production of 2.5 Mbbbl/d in 2040 if the technology is at the industrial stage.

2.4. Gas to Liquids Technologies (GTL)

GTL is a technology for converting natural gas to petroleum products (mainly diesel, kerosene, naphtha and waxes). To obtain an idea of the theoretical potential for GTL, a selection of concerned countries was made on the following basis: selection of countries having over 200 Bcm of proved reserves or four times the minimum for a 20 000 b/d plant (20 000 b/d of GTL capacity requires 2 Bcm per year of production or 50 Bcm over 25 years); countries having a reserves-to-production ratio above 25 years an finally selection of gas autonomous or exporting countries.

The result shows that the potential for GTL represent 161 Tm³, corresponding to 73 % of the today gas reserves. 44.6% of the volumes are located in Middle east and especially in Iran and Qatar. 35% are in FSU, mainly in Russia. Other potential exist in Africa (8%) especially in Nigeria and Algeria, in Asia (6.5%) mainly in Indonesia and Australia and finally in South America and Europe in a small proportion.

The earliest applications took place in Germany, during the Second World War, to produce motor fuel. In 1955, South Africa then initiated a vast program to produce motor fuels from gas and the first GTL unit using gas was built in 1991. Today, South Africa's Sasol is the world leader in Fischer-Tropsch technology, and South Africa is the foremost producer of FT synthesis fuel in the world (nearly 200 000 barrels per day (b/d), including coal based units.

The last years marked the real debut of this industry, with the construction of many pilot plants. These various achievements have culminated in a technology that can be considered as operational, although it's technical and economic viability remains to be demonstrated with large scale units. The announced unit cost of GTL technology has dropped sharply: from over 50 000 \$/bbl/d, unit cost is now about 25/35 000 \$/bbl/d and some operators have targeted under 20 000 \$/bbl/d. GTL technology is therefore an available technology, even if its large-scale reliability remains to be demonstrated, and is economically profitable for a sufficiently low raw material price and a minimum crude oil price comprised between 15 and 25 \$/b

(depending on the assumptions made for investments -25/35 000 \$/b/d – and for the price of gas – 0.5/1 \$/MMbtu).

3 units are running end 2006, with a cumulated production of about 85 000 bbl/d. They are located in South Africa, Malaysia and Qatar. Lots of projects are also announced and eleven can be considered as serious. They are mostly located in Qatar but even in Nigeria, Australia, Bolivia, Papua New Guinea and Algeria. Their respective commissioning dates are highly fluctuating, but a total world production of about 0.45 Mb/d in 2012-2015 and 1 Mbbl/d in 2015-2020 appears to be realistic, regarding those announced projects and consistent with other estimates. Qatar should become the first nation regarding Liquids from gas production with an estimate of 800 000 b/d around 2020 which represent 80% of the forecasted production that year.

2.5. Coal to Liquids Technologies (CTL)

World reserves of coal are enormous and, compared with oil and natural gas, widely dispersed. According to the WEC World Energy Council, proven coal reserves at end 2005 are estimated at 909.1 billion tonnes located 33% in Asia/pacific, 32% In Europe and FSU, 28% in North America, 5.5% in Africa and Middle east and 2.2 in South and Central America. Almost half the world's reserves are located in OECD countries, and concerns over coal supply security are less important than for oil and gas. The size of the resource base is not the restraining factor for coal to be able to continue supplying a considerable portion of world primary energy demand (more than 65% share for power generation), and particularly for the production of fuels. At that time the restraining factor was identified as a question of the development of production facilities and infrastructure.

Liquid fuels have long been produced from coal. As the cost of converting coal into useful liquid fuels is higher than the cost of refining crude oil, it is relative price of the raw feedstock that has provided the main incentive to pursue the technology. The major exceptions resulted from the isolation of a country from reliable, secure sources of crude oil. Germany produced substantial amounts of coal-derived fuels during the Second World War, as did embargoed South Africa between the mid-1950s and 1980s.

Coal may be used to produce liquid fuels suitable for transportation applications by removal of carbon or addition of hydrogen, either directly or indirectly. The first approach is carbonisation or pyrolysis but the liquids produced are of low quality and this has not been successfully demonstrated to date that these processes can be economically viable. The second approach is liquefaction, either direct or indirect. Many different "direct" liquefaction processes have been developed, but most are closely related. By the way, direct liquefaction is the most efficient route currently available. Liquid yields in excess of 70% by weight of the dry, mineral matter-free coal feed have been demonstrated. The only operating process for the "indirect" liquefaction of coal is South Africa's Sasol process, with three operating plants. The main unit specific to indirect liquefaction is the synthesis reaction step. Underground coal gasification is another possible technology. However it is non-mature and many hurdles need to be overcome before any project can go ahead.

Three operating plants produce today fuels from coal in South Africa. The units are running about 164 000 bbl/d of fuels. China, where coal resources are huge, aims to produce 400 000 bbl/d of fuels from coal in 2020. Some projects are well ongoing and one can think that 260 000 bbl/d in 2013 in China is reasonable. In United States, the first unit should start in 2011 with a production of 18 000 bbl/d. Lots of projects around the world are actually in a study stage and should be effective if that first project is decisive. It is reasonable to think that the worldwide production of liquids from coal should be **around 600 000 bbl/d in 2020. If** China reaches its goal of a production of 400 000 bbl/d in 2020, the country will represent 66% of the worldwide production of liquids from coal.

2.6. Summary of the non conventional supply over 2000 to 2020

According to the current production and the future projects that we have described in the previous paragraphs, the non conventional supply is and should be concentrated in the following areas: Canada (tar sand), Venezuela (extra-heavy crude oil), USA (future oil shale), Qatar (GTL) and China (CTL). In 2005, this production only stands for around 2.3% of the world-wide oil supply which was around 81 Mbb/d (3 900 Mt/y). Nevertheless, this non conventional supply should increase during the next decades as described in table 6. According to the current production capacities and to the ongoing projects, the expected non conventional supply could reach around 7,2 Mbb/d (332 Mt/y) in 2020. The energy forecasts point out a global increasing trend of the energy demand over the next decade. Thus, in the recent reference scenario of the International Energy Agency (World Energy Outlook, 2006), the World primary energy demand could reach 105.7 Mbb/d of oil in 2020. Thus the non conventional supply should represent 6.5% of the global oil supply in 2020.

Table 6 – World-wide extra-heavy crude oil production (in ‘000 barrel/day)

<i>Year</i>	<i>Canada tar sand</i>	<i>Venezuela extra-heavy oil</i>	<i>Oil shale</i>	<i>Liquids from gas</i>	<i>Liquids from coal</i>	<i>Total</i>
2000	476	155	11	50	164	845
2005	1 017	584	11	50	164	1 810
2010 (**)	2 110	584	ε	255	190	3 135
2020 (**)	3 990	1 200	ε	1 000	600	7 195

(**) : expected production according to the current and future production capacities

3. Modelling approach

The non conventional crude supply has been introduced in a world-wide refining model. The OURSE (*Oil Used in Refineries to Supply Energy*) model is a world-wide multi-areas refining model which is designed to simulate the world oil product supply for the POLES (*Prospective Outlook for the Long-term Energy System*) model of the European Commission (Lantz and al., 2005).

Linear programming (LP) models are frequently used in the refining industry, both for refinery management and for investment analysis. As marginal cost pricing is relevant for the oil products, an LP model has been built for this world-wide refining model. The model has been developed on the GAMS software associated with the CPLEX optimisation code. According to the size of the model (around 14,000 constraints and 66,000 variables), an interior point method is performed.

For a given set of crude oil production, oil prices and oil product demand, the OURSE refining model provides : the crude oil supply of the refineries for nine main regional areas in the World, the refineries throughput and the oil product balances of each region, the products blending (allowing compounds from biomass), the investments (refining processes) and the marginal cost of oil products. Furthermore, under some assumptions, the long run marginal costs could be used as ex-refinery prices. Then, they could be used on the demand side modelling.

Several dozen different crude oils are processed in these regions of the World even if the concentration curves show that a large part of the supply is made up of only a few of them. Because the size of a LP model is approximately proportional to the number of crude oils considered, it is impossible to represent all of them in the refining model. Consequently the crude oil supply has been "reduced" through a limited number of representative crude oils. Five "typical" crude oil qualities have been introduced in the model : Brent (37.0 API, 0.32 %m sulphur content), Arabian Light (33.4 API, 1.86 %m sulphur content), Arabian Heavy (27.9

API, 2.69 %m sulphur content), Forcados (31.0 API, 0.20 %m sulphur content) and condensate (> 50.0 API, < 0.10 %m sulphur content).

Nine main regions are considered in the model : North America, Latin America, Northern and central Europe, South Europe, Former Soviet Union, Africa, Middle East, China and Asia (except China).

In our simulations, the oil price is exogenous as well as the conventional crude oil supply. Then, according to the demand of oil products, the non conventional oil supply pattern is determined from the model optimisation. In the model framework, the extra-heavy oil and the tar sand productions are introduced to supply the refineries ; the GTL and CTL productions are introduced through processing units in the refineries schemes. Due to the weakness of information, the level of oil shale production is determined outside the modelling approach based on expertise.

The non conventional crude oil supply represents both the non conventional crude oil extraction process and the production of synthetic crude oil through the upgrading processes. This synthetic crude oil production is split into the five "typical" crude oil categories which are considered as input feed of the refineries. Thus, the two main categories of non conventional crude oil described before – extra-heavy oil and tar sand – increase the crude oil supply mainly concerns Latin America with the extra-heavy oil in Venezuela and North America with the Canadian tar sands. The non conventional crude oil supply is derived from the production and the upgrading capacities, the reserve availability and the recovery factor. The investment behaviour in the non conventional crude oil resources is based the economic theory of exhaustible resource (Pindyck, 1978, 1980). We assume that the producers maximize their discount profits with respect to the production capacities and to the resource availability.

4. Empirical results

The oil product demand has been simulated over the next 25 years in a business as usual scenario. In this scenario, the oil price is 55 \$/bbl in 2030. The demand of oil products around reach 5 362 Mt/year (107.3 Mb/d) for the final year (table 8). This demand which represents the final oil products consumption and the demand for electricity generation is addressed to the world-wide refining industry through the optimisation process described before.

Table 8 – Oil product demand in 2030, business as usual scenario (final demand + demand for electricity generation)

<i>Product</i>	<i>North Am.</i>	<i>Latin Am.</i>	<i>NW Europe</i>	<i>South Europe</i>	<i>FSU</i>	<i>Africa</i>	<i>Middle East</i>	<i>China</i>	<i>Asia & Pacific</i>	<i>Total</i>
<i>LPG</i>	98.0	29.9	18.0	15.0	14.4	12.6	31.7	36.5	122.1	378.1
<i>Gasoline</i>	589.4	75.7	71.1	44.9	60.3	51.8	85.2	100.6	305.9	1384.8
<i>Naphtha</i>	25.9	19.2	46.2	13.4	1.1	3.3	11.5	55.9	187.2	363.7
<i>Diesel oil</i>	159.5	94.8	155.9	76.7	21.3	45.3	32.6	62.0	288.9	936.9
<i>Heating oil</i>	139.8	41.1	102.4	36.7	45.2	34.0	97.8	118.7	338.8	954.6
<i>Jet fuel</i>	126.7	18.3	54.8	16.1	20.2	10.7	10.0	17.6	69.6	344.0
<i>RFO+others</i>	130.0	60.2	47.2	61.3	77.5	51.1	82.7	56.5	189.7	756.3
<i>Maritime bunkers</i>	53.6	13.8	40.6	20.4	0.2	15.6	14.3	13.5	72.2	244.2
<i>Total</i>	1 322.8	352.9	536.2	284.4	240.2	224.4	365.8	461.4	1 574.4	5 362.5

Unit : million of metric ton

After the optimisation, the high values of the marginal cost point out the opportunities of development for non conventional oil (table 9). More particularly, the marginal cost of gasoline in North America and the marginal cost of diesel oil in Europe underline the tensions for these two products

Table 9 – Marginal cost of gasoline and diesel oil in 2030

	<i>North America</i>	<i>Europe</i>	<i>Asia</i>
Gasoline	513.2	458.3	460.5
Diesel oil	392.2	485.4	473.0

Unit: US\$/tonne

The total primary oil supply in 2030 is around 112.4 Mbb/d. This include the CTL, GTL production and the biomass contribution which raise at 1.8 Mbb/d. The conventional crude oil supply represents around 102 Mbb/d with an important share of the Middle East (46.9 Mbb/d). Concerning oil shale, several values of the technical and economic parameters in 2030 have been introduced in a sensitivity analysis. The potential production could raise at around 500 000 bbl/d in some cases. In 2030, non conventional supply as defined in this paper should reach 10.4 Mbb/d which represent 9% of the world oil supply. The Canadian and the Venezuelan synthetic crude oil production growth up to, respectively, 4.8 Mbb/d and 1.5 Mbb/d. The contribution of North America to the worldwide crude oil supply should be around 19% and the Middle East stands for 40 % of the refining industry supply (Table 10).

Table 10 – Crude oil supply (including non conventional supply) in 2030 – reference scenario

	Conv. crude oil	Extra-Heavy oil	GTL-CTL	Biomass	Total
North America	17.6	4.8	0.02		22.4
Latin America	7.8	1.5			9.3
Europe	1.6				1.6
FSU	13.8				13.8
Africa	8.4		0.6		9.0
Middle East	46.9		1.0		48.0
China	2.2		0.4		2.4
Asia	3.6		0.3		4.1
				1.8	1.8
Total	101.9	6.3	2.4	1.8	112.4

Unit : Mbb/d

The evolution of the final oil product demand is driven by the activity of the transport sector which stands for around 60 % of the demand in 2030. Thus, the strong increase of the diesel oil consumption which grows up to 937 Mt in 2030 involves some important investments in the refining industry in hydrocracking and hydrodesulphurisation units. Moreover, Europe and Asia will import some increasing quantities of middle distillates. Thus, the development of the GTL production (mainly in the Middle East) could be highly valued due to the high price of diesel oil (marginal cost obtained through the model optimisation). Furthermore, this will diversify the European imports of diesel oil which are strongly depending on the FSU

exports. In Asia, mainly in China, the development of the CTL production should also make a significant contribution to the oil product demand. At the World-wide level, the GTL and CTL production could reach around 2.4 Mbb/d in 2030.

Nevertheless, several sensitivity analyses have been carried out concerning the feedstock price of the CTL and GTL units. A too high value of the coal and gas prices should influence the capacity level of these productions.

In the environmental scenario, we assume that the oil product demand is 5% lowest than the demand for the main products in the reference scenario and stands at 5094 Mt (102.3 Mbb/d). Furthermore, we introduce a tax of 40\$/ton on CO₂ emissions. After the optimisation, the marginal costs of the oil products remain approximately the same as in the reference scenario which indicate the same potential for the development of non conventional oil. Consequently, the conventional crude oil supply is reduced and represents around 97 Mbb/d (cf Table 11).

Table 11 – Crude oil supply (including non conventional supply) in 2030 – environmental scenario

	<i>Conv. crude oil</i>	<i>Extra-Heavy oil</i>	<i>GTL-CTL</i>	<i>Biomass</i>	<i>Total</i>
North America	17.5	4.8	0.02		22.3
Latin America	6.0	1.5			7.5
Europe	1.6				1.6
FSU	10.7				10.7
Africa	8.4		0.6		9.0
Middle East	46.7		1.0		47.8
China	2.1		0.4		2.4
Asia	3.6		0.3		4.1
				1.7	1.7
Total	96.7	6.3	2.4	1.7	107.1

Unit : Mbb/d

Finally, all these results could be considered as too optimistic. As Pindyck (1980) points out, an oil producer could keep its resource if the resource prices are volatile. In this case, the expected higher profits in the future should involve a slowest pattern for the non conventional oil supply.

Conclusion

Non conventional resources represent a huge potential in terms of resources. They are either of a high strategic importance in term of diversification of oil supply and enhancement of supply security. In fact, the non conventional resources are more balanced over the five continents than the conventional crude oil.

Four main issues raise from this study:

- the increasing oil products demand in 2030 involves the development of the non conventional supply. It should represent 9% of the total oil supply;
- thanks to the tar sands development, North America should keep a quite stable share of the total worldwide oil supply at 19%;
- Liquids fuels from GTL and CTL technologies should give significant contribution to the increasing automotive fuel demand in Europe and Asia;
- Concerning oil shale, according to the improvement of the industrial technologies, they could slightly reinforce the North American supply.

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