Chapter 9

Gasification a Driver to Stranded Resource Development

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Additional information is available at the end of the chapter

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1. Introduction

When evaluating natural gas projects, stakeholders and decision-makers have been traditionally limited by the requirement for large reserves to be recoverable before any investment can be committed. Technological advancement and commercial know-how has unlocked many potential reserves that would technically be considered stranded or entirely overlooked by IOCs (International Oil Companies) and NOCs (National Oil Companies). This has important implications for policymakers as it can affect the way natural gas is utilised as an indigenous supply, an export resource or substitution fuel.

There have been some structural changes in the way the gas sector operates over the last decade. This has been an exciting time for market observers, as political, economic, financial and technical inputs have driven major changes in the industry.

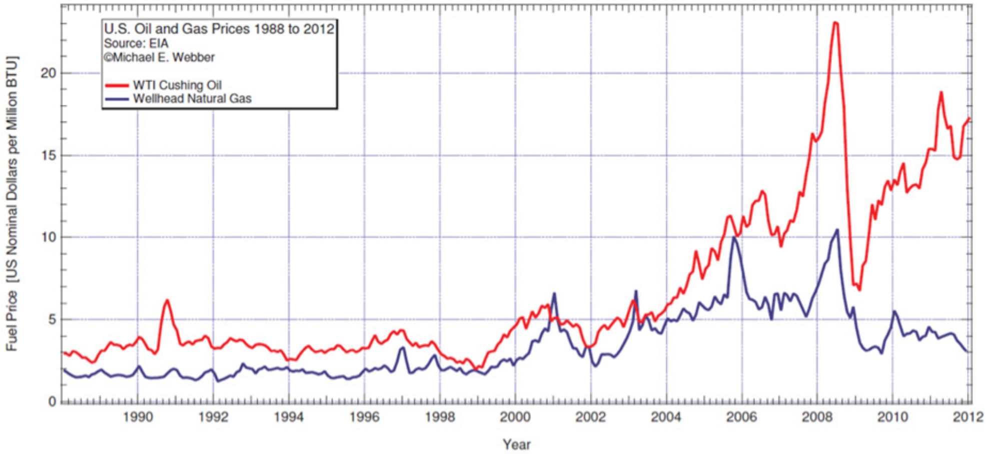
One of the ways that the industry has changed is the attention to using gas in less traditional methods. To understand how this has developed, this chapter analyses the major recent trends, the traditional market characteristics and discusses the outlook of potential future changed in the field of natural gas development, production and processing.

When looking at gas field development, stakeholders evaluate a number of options to monetise gas. These options are limited by a host of factors, each with a unique position with respect to geography, government, market and political dynamics.

This chapter acts as an overview of the monetisation routes and the options that are becoming available to decision-makers.

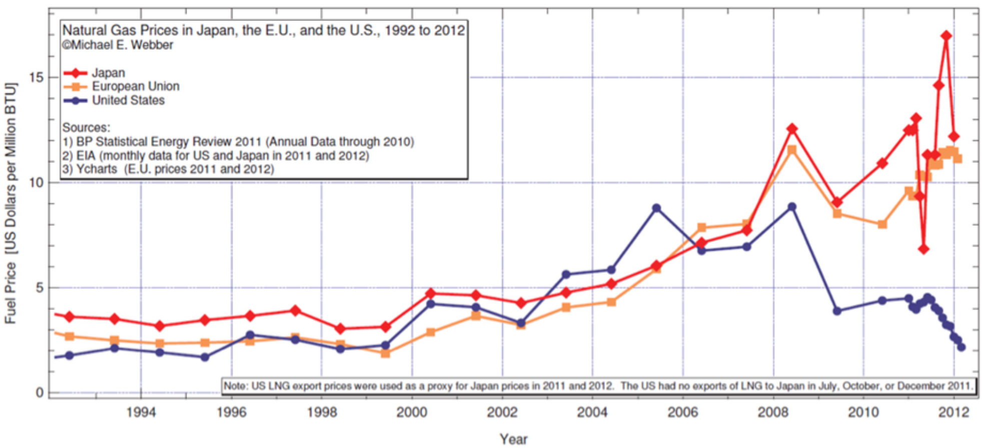
2. Current and future trends of oil and gas market

Over the past decade, there has been a paradigm shift in the behaviour of the oil and natural gas markets. Compared to the traditional model, where gas production was secondary to the production and marketing of oil, and prices of gas were naturally linked to the price of oil (or a basket of oil products), we have seen gas emerge as in increasingly important fuel with a decoupling of prices. This has been particularly evident in the North American market, where competitive forces and regulation of the midstream sector allowed for an emergence of a separate gas market, marked by consistently high liquidity. There has also been a discrepancy in the regional gas price, which lends to arbitrage activity by spot traders, and some LNG (Liquefied Natural Gas) cargoes have been redirected from initial destinations to other markets, even whereby destination clauses in contracts have been broken.



Source: IEA, Michael E Webber, 2012Figure 1

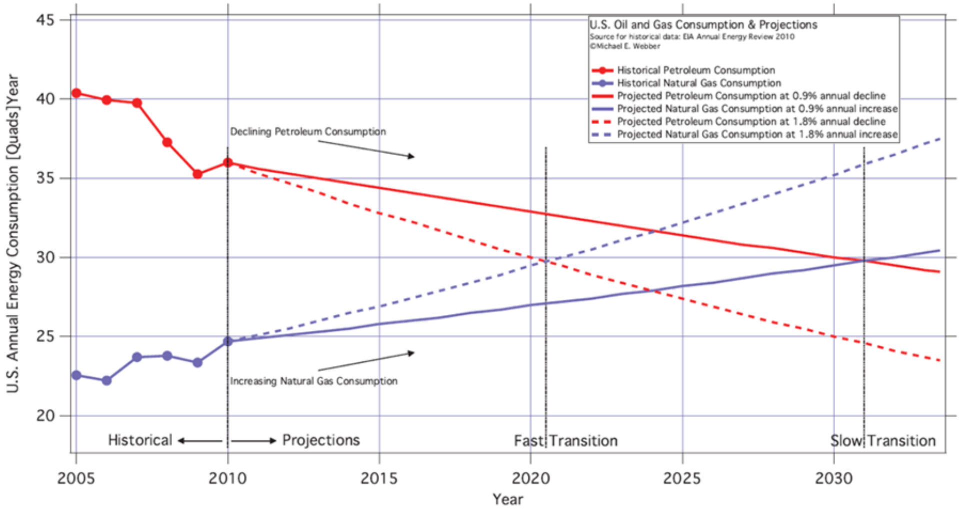
Figure 1.



Source: IEA, BP Stats Review, Michael E Webber, 2012

Figure 2.

There is some expectation that natural gas consumption may over take oil consumption by 2030, which will result from a number of pressures on oil consumption, ranging from economic and environmental, to issues relating to security of supply.



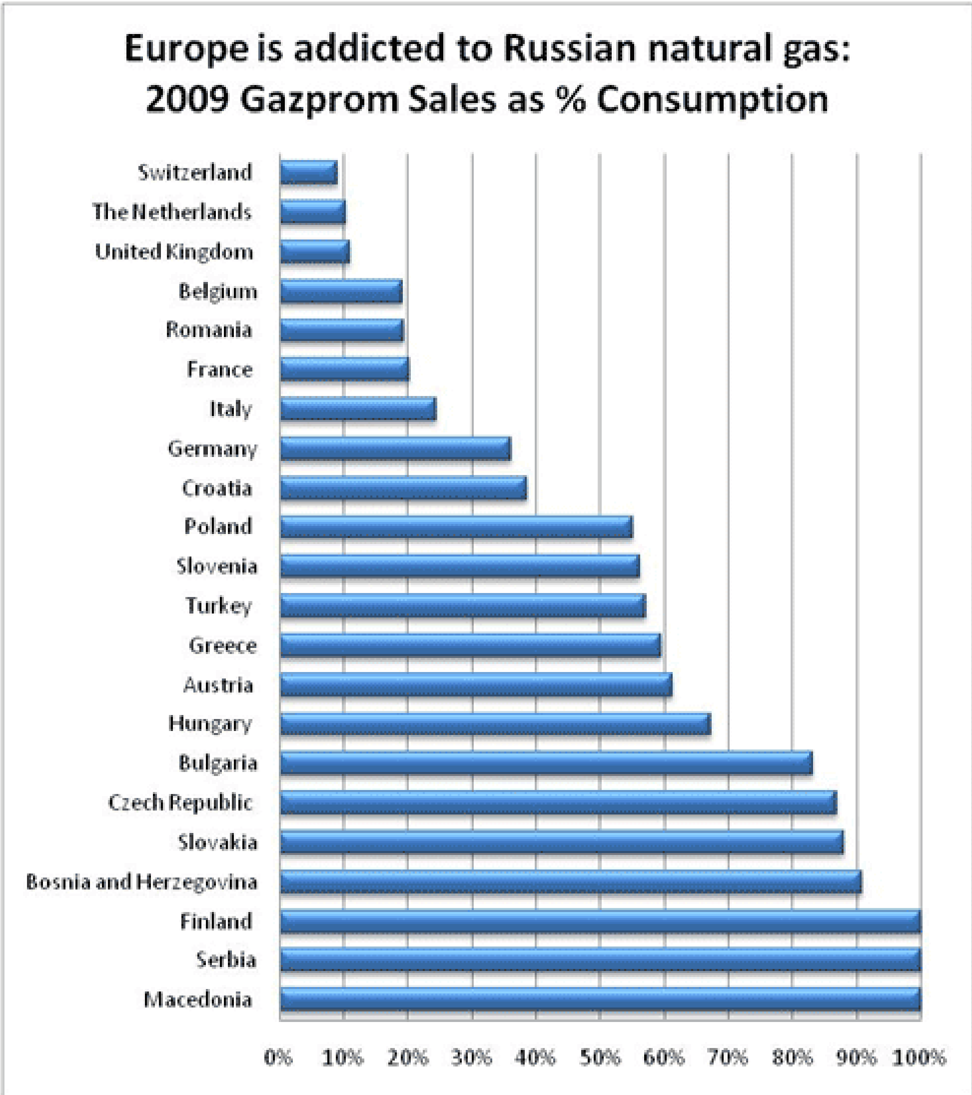
Source: EIA, M Webber, 2012

Figure 3.

In Europe, this shift has seen a slower uptake. A primary reason for this is the separation of supply and demand centres, with the EU zone increasingly relying on imported gas. The biggest supplier to this market is Russia, also the world's largest producer of natural gas, which as been supplying gas to Europe via soviet built high pressure interregional trunk pipelines.

The majority of contracts are long term take-or-pay contracts which have a price formula as an index linked to a basket of refined products (the "substitution fuels"). Historically, long-term contracts have played an important role in the development of the European gas market by providing a risk sharing arrangement between producers and buyers, enabling important new investment into production and infrastructure projects to be undertaken. The Eurozone realised that their growing gas needs, the bulk of which are met with Russian gas, can only be adequately supplied if Russia is able to invest in new gas fields and pipeline construction. They took a position that if gas is supplied exclusively through spot transactions, gas suppliers, Gazprom included, will not be willing to shoulder the risks associated with multi-billion dollar investments and substantial quantity risks. Corporate strategy aside, it would be impossible to access the international capital markets without guaranteed offtake contracts being in place. [1] Thus, contracts of 20 years or more have been a normal occurrence in the European continent.

[1] The dynamics of funding such projects are very complex and are out of the scope of this article; however it is worth mentioning that domestic markets of major producers lack the hard currency to finance national champions whilst international capital markets generally shun away from risks associated with emerging market domestic consumption.



Source: IEA, 2010

Figure 4.

country	contract term	volume of annual supplies	description	additional agreements
Austria	2012–2027	7 billion m^3	contract signed by Gazprom with OMV, EconGas as well as with GWH and Centrex Europe Energy & Gas AG, affiliated to Gazprom	The rules for gas reception have changed: - change of gas recipient from OMV to EconGas ; - GWH and Centrex, which are affiliated with Gazprom, were granted the right to sell gas (nearly 1.75 billion m^3 annually) to Austrian end-users
Germany (VNG)	2014–2031	5,25 billion m^3 (possibility of incre-asing supplies)	contract signed by WIEH (a joint venture of Gazprom and Wintershall) and Verbundnetzgas (VNG). Gazprom sells gas via WIEH in the markets of other EU member states	
Germany (E.ON)	2011–2036	4 billion m^3 (Nord Stream)	contract signed by Gazprom and E.ON on supplies via NS gas pipeline	
Germany (E.ON)	2020–2035	20 billion m^3	contract signed by Gazprom and E.ON, being an extention of the currently binding contracts (to expire in 2020)	
Italy	2017–2035	22 billion m^3	contract signed by Gazprom and ENI which constitutes a part of the new strategic partnership agreement; extention of the terms of the currently binding contracts	- companies affiliated with Gazprom (GMT Italia, Centrex) have gained access since 2007 to the Italian domestic market, and sales of up to 3 billion m^3 annually in 2010 is allowed - ENI has been promised the right to buy assets in Russia
France	2012–2030	12 billion m^3 + 2,5 billion m^3 (Nord Stream)	contract signed by Gazprom and Gaz de France ; the currently binding contract is prolonged, and an agreement for supplies via the Nord Stream gas pipeline is concluded	- Gazprom's subsidiary, GMT France, has been granted access to the French domestic market, and is allowed to sell up to a maximum of 1.5 billion m^3 of gas annually from 2007
Czech Republic (RWE)	2014–2035	9 billion m^3	contract signed by Gazprom and RWE Transgas; prolongation of the previous agreement on gas supplies to, and transit through, the Czech Republic	
Czech Republic (Vemex)	2008–2012	0,5 billion m^3	contract concerns supplies of gas to the Gazprom-controlled company which supplies gas to some Czech industrial customers	
Bulgaria	2011–2030	3 billion m^3	Gazprom and Bulgargaz have signed a contract prolonging the previously binding contract	
Romania (WIEH)	2012–2030	4,5 billion m^3	the previously binding contract has been prolonged	The contract's prolongation is made dependent on its renegotiation, and switching to cash payments for gas transit. The agreement provides for the increase of the gas transit through Bulgaria in exchange for co-operation in the implementation of Russian gas pipeline projects.
Romania (Conef)	2010–2030	2,5 billion m^3	Gazprom and Conef Energy SRL have signed a contract; supplies for Alro Stalina aluminium plant	
Denmark	2011–2031	1 billion m^3	Gazprom and DONG Energy have signed a contract for supplies from NS	

Based on *Gazprom in Europe: Faster expansion in 2006*, Ewa Paszyc, Centre for Eastern Studies, Warsaw, February 2007; data quoted from the companies' websites and news agencies

Source: Ewa Paszyc, Centre for Eastern Studies, 2008

Figure 5.

A number of drivers have begun to put significant pressure on the traditional model. Working in tandem, the economic growth on the continent, together with significant global environmental concerns and directives, has delivered a growing demand for natural gas. At the same time, as indigenous supplies begin to plateau and decline[2] and governments become more reliant on imports, Security of Supply issues begin to make their way up national policy agendas. From a security of supply standpoint, there have traditionally been three pillars of national strategy for policymakers – development of indigenous supplies, diversification of suppliers and reduction in consumption.[3] From the three pillars, the fastest route is evidently the diversification of suppliers as consumption reduction and indigenous suppliers requires significant lead-times. Certainly it is difficult to diversify in a timely manner if transit is to take place via pipelines, however, as the market of liquefied natural gas became more mature, it allowed for an efficient way to introduce new suppliers. Regasification terminals are significantly less complex than liquefaction terminals, and began to appear in a host of European coastlines.

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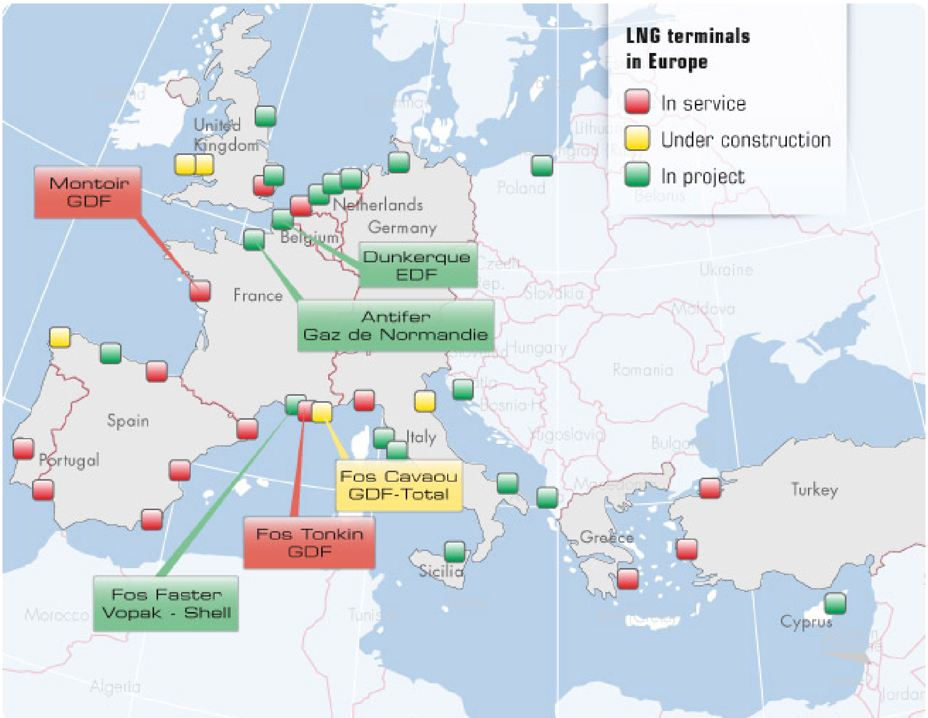
[2] From the major producers, the UK North Sea production is in decline, Dutch production is capped, and Norwegian fields are in plateau (although there is heavy E&P activity).

[3] Temporary relief was seen during the 2007-2011 financial crisis, as demand destruction allowed for a temporary shift from "sellers market" to "buyers market" and attention of the ministers was diverted to dealing with the financial economy and the failing UN Framework Convention on Climate Change.



Source: GdF, 2011

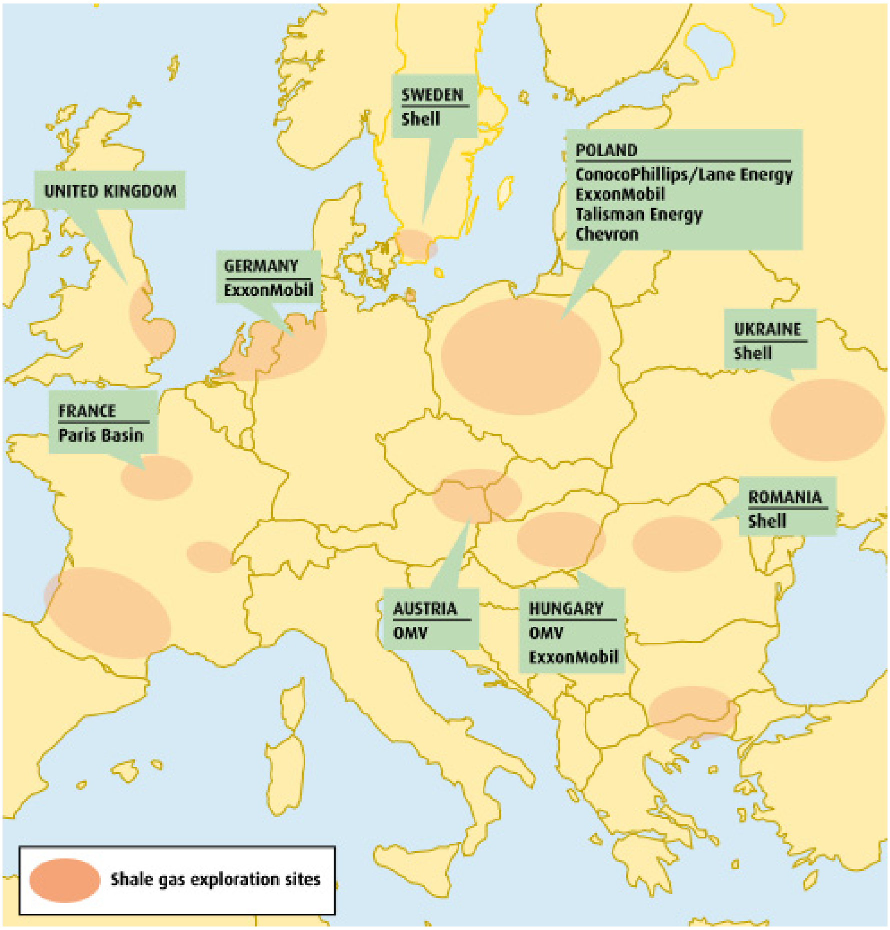
Figure 6.

European competition rules have created somewhat of a stumbling block for these initially, but investment arrived in sufficient quantity to allow for an emerging spot market in the European gas hubs. The net effect of this has been an evolution of long-term contracts with certain traditional terms being re-examined and renegotiated. Some of the centrally important clauses such as duration/period are seeing a decrease from the frequently encountered fifteen to twenty-five years to perhaps eight to twelve years in length. This is, in part, due to the contract volumes also decreasing with new project supplying between three and ten BCM (Billion Cubic Metres) annually as opposed to the traditional ten to twenty BCM. Take-or-pay obligations are also become less stringent, with increasing "carry-forward" and "make-up" rights. Index pricing is being replaced in highly competitive markets by daily pricing derived from a liquid short term market, such as the UK National Balancing Point. Certainly this trend will apply to some of the new export contracts yet others, which intend to supply large volumes and require substantial infrastructure investment, will be done under traditional terms.[4]

What cannot go unmentioned is the shale gas development. The flurry of exploration activity has seen significant results in adding major volumes to reserves in the US, and has

[4] Nord Stream and South Stream, for example.

become a game-changer in the US domestic market. The effect on global markets has not yet been so dramatic, although exploration activity for shale gas in the Eurozone has excited many a journalist and energy observer. Thus far, however, the UK has enforced a temporary ban on shale gas fracking and Poland's estimate of reserves has so far been cut by a factor of ten. How this develops could have a profound effect on the industry.

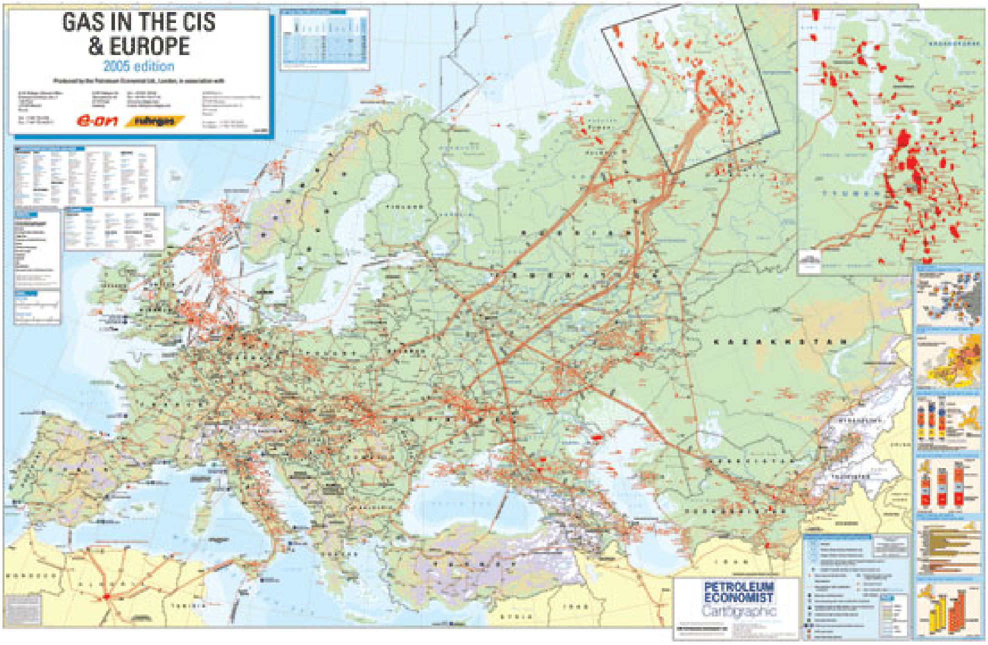


Source: Energy Tribute, 2011

Figure 7.

3. Traditional gasification uses

Where gas has been discovered in abandoned supply, the stakeholders had a very clear picture of how this asset can be monetised. The most straightforward solution has been the construction of a pipeline from the supply centre to the consumption centre, where gas would be used for heat and power generation, industry and grid supply. Pipelines can run for many thousands of kilometres, over different and difficult terrain, across borders, through mountains and under water.



Source: Petroleum Economist, 2006

Figure 8.

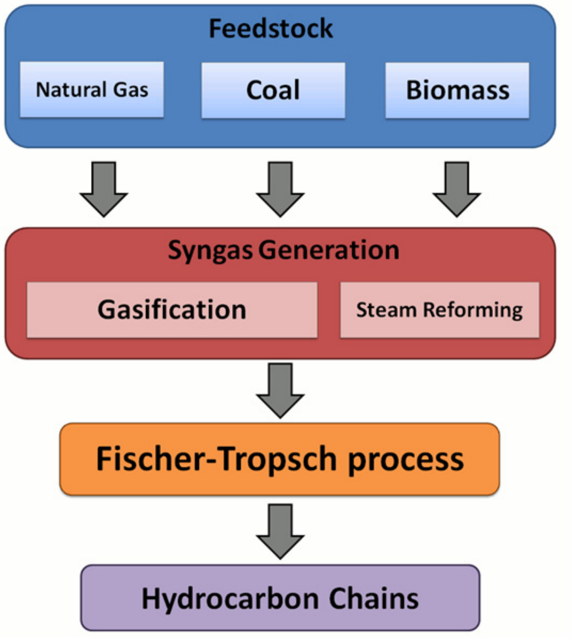
If the consumption centres were satisfactorily supplied, or if the cost of the pipeline was prohibitively expensive, gas was either left in the ground, or converted into a final product that could be transported as a liquid or solid to other distant markets.

These conversion routes are what are known as the "Gas-to- " technologies and are specifically Gas-to-Chemicals, Gas-to-Liquids and Gas-to-Power. Recent advances in technology have allowed these processes to become available as economic methods not only to utilise stranded gas but to take advantage of pipeline gas that may be limited in its transport options.[5]

Gas-to-Liquids (GTL) is a process that was initially discovered by Fisher and Tropsch during the World War II and has seen various applications thereafter. In essence, it is a petrochemical process that converts methane (major component of natural gas) into a synthetic diesel fuel that is environmentally clean as it contains no sulphur and is aromatics free. The first major commercial GTL facility was built in South Africa by Sasol, using coal gasification to produce the feedstock and manufacturing diesel oil. It is generally accepted

[5] Russian independent gas producers are prohibited from exporting natural gas by law (Federal Law "On Gas Export", 2006).

that due to economies of scale, GTL facilities become economic with large output capacities and extremely low feedstock cost. As such, new plants are expected to be in excess of 100,000 barrels per day (bpd) of product, and located in the Middle East or Africa[6]. Multi-billion dollar projects such as Shell's Pearl GTL in Qatar and Oryx GTL (Qatar Petroleum and Sasol) are leading examples of this technology in application. Another 200,000 bpd plant has been proposed in Australia.



Source: Stamford University, 2010

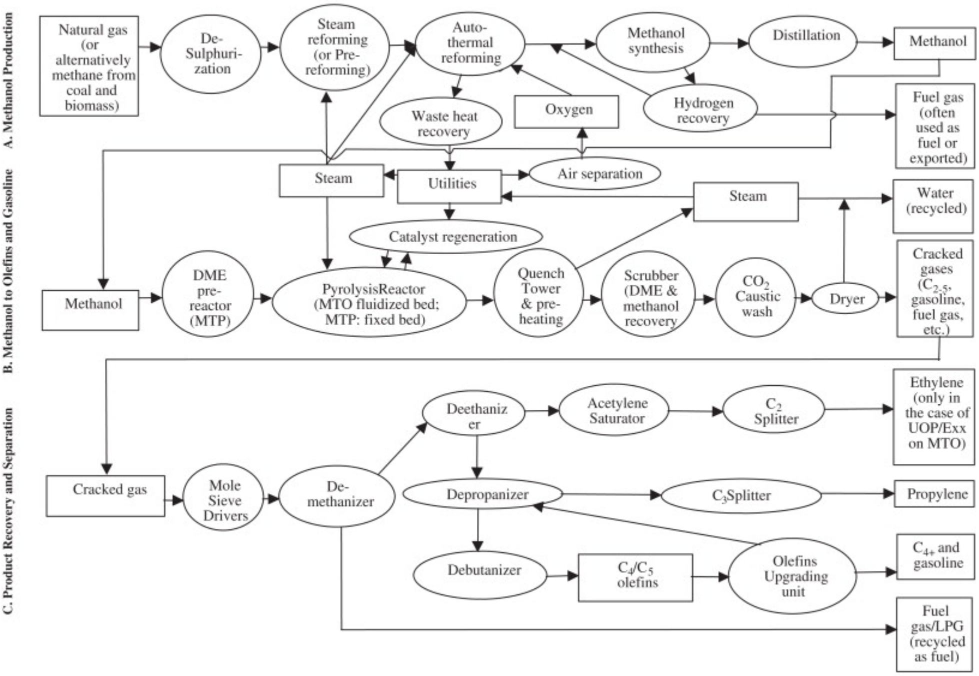
Figure 9.

The Gas-to-Chemicals (GTC) process is a very mature process. This involves the conversion of methane to a chemical product, either an intermediate or final stage. Indeed, more value is captured the further down the process chain that one is able to proceed. The most common product is Ammonia which is used in the production of fertilizers. The high oil price has been somewhat of a double-edged sword for the price of fertilizers since the increase in the feedstock (where natural gas is still tied to the oil price) and also the increase in demand driven by the biofuels surge as a means to find alternative energy solutions. Because natural gas makes up about 70% of the cost of production, European based producers can no longer compete with producers with a low cost base such as Russia, or even Ukraine (due to special relationships with Russia[7]). There is a clear link between

[6] SassolChevron is in the process of building a 34,000 bpd plant in Nigeria.

[7] This does not refer to inter-governemental price agreements but to private agreements between Gazpromexport and Ukrainian fertiliser producers.

financially stable fertiliser producers and a low gas source. As more producers are forced to shut down or relocate, and food scarcity continues to haunt developing countries, fertiliser production will remain a highly lucrative option for GTC processing. Another common product is methanol, and whilst a very price volatile product, it can itself be used as an intermediate to produce more valuable products. The methanol to olefins (MTO) process chain is a lucrative way to capture added value. Given the recent worldwide rise in the use of polymers, this particular process has spurred a myriad of activity. The process can be tuned to produce polypropylene and polyethylene. Given the issues outlined above, it makes sense to commission boutique-plants with capacities not exceeding 150,000 tonnes per year. Certainly scale economies are also achieved in this process, but given factors such as political risk and competitive pressures from new producers, it seems prudent to seek a short project pay-back period. Thus, given that the project is Capex sensitive, it is advisable to seek new, low cost technology that has become available in China and has half the cost of similar European technology.



Source: Energy, Volume 33, Issue 5, 2008

Figure 10.

Other polymers that may be of interest in the GTC segment are PBT (Polybutylene terephthalate) and PET (Polyethylene terephthalate). These are thermoplastic polymers that are used in the production of electrical insulators or plastic bottles and synthetic fibres respectively. PBT is a less widespread product, however its versatile nature sees the market grow at 7% annually. One route to its production would be via 1,4-Butanediol which can be produced from propylene, itself produced from methanol. Like many of these processes, the rights are protected by international patents and it is necessary to approach the patent holders to implement them. The manufacturing process of PBT via 1,4-Butanediol is patented by Zimmer, now part of Lurgi AG. In most cases, patent holders are willing to grant user licenses to return research and development costs. This is not the case with PET however, as the necessary intermediate is Acetic Acid, produced from methanol via only two economical routes. These routes are patented by BP Chemicals and Celanese, which between them control the acetic acid market. These companies do not grant licenses to third parties and as such, gas owners would need to yield a majority stake to the licensors. Nevertheless, acetic acid, and subsequent PET production is an extremely lucrative method to monetise stranded or semi-stranded gas. These projects are indeed capital intensive and require considerable upfront investment. A 500,000 tonne acetic acid plant with a PET production line could cost in excess of $800+ million.

Gas-to-Power (GTP) involves the conversion of natural gas to electricity and normally implies in-situ generation. GTP has become a viable option since the introduction of the combined cycle gas turbine (CCGT), a system where the gas turbine is driven to produce electricity whilst the heat is used to manufacture steam to generate additional electricity through a steam turbine. These plants are much more efficient than their traditional counterparts[8] and are more compact is size. Furthermore, the construction lead times usually do not exceed two years, which is a significant improvement on traditional power plants. In situ GTP is particularly applicable when gas is found in undeveloped urban centres with a low degree of residential and commercial gasification. Gasification refers specifically to the level of development and infiltration of the low pressure distribution networks that supply gas to local residents or small commercial users. Africa and India, both of which have discovered gas near populated areas, would see great benefit from such technology. Nevertheless, Nigeria, which holds Africa's largest natural gas resources, flares more gas than any other country, after Russia.

In fact, there has been some discussion about applying old jet engines as temporary gas turbines for local power production. Because gas is considered a clean fuel, and due to the CHP Directive[9] in the EU urging the construction of such plants, CCGTs are likely to take a dominant role in the addition of new generating capacities, on the demand centre side. The major draw-back is the necessity to be located next to high-voltage electrical infrastructure, which makes it highly likely that gas transport pipelines will be found in the vicinity, in such a case yielding preference to the GTC process. In Russia's case, if a CCGT plant may be located near a European border, then, receiving access to the grid, it may be possible to export electricity to Russia's neighbours. However, as most of Russia's gas is located thousands of kilometres from the borders and large distances from major residential or industrial areas, CCGT is not a viable option. Instead, it becomes as viable option only at the

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[8] A CCGT plant shows to have a conversion efficiency of 65%, as compared to a traditional gas turbine of 33%.

[9] Directive on the promotion of cogeneration based on a useful heat demand in the internal energy market and amending Directive 92/62/EEC

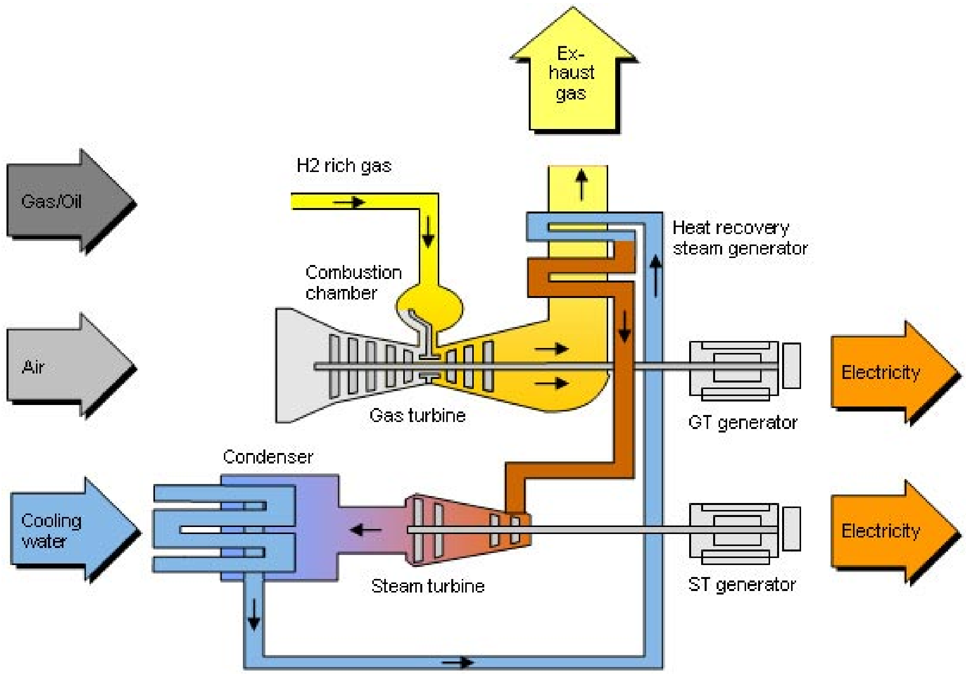
receiving end of a gas chain. As there is significant delay and uncertainty surrounding the nuclear power route in Europe and the UK, CCGT will play an ever increasing role.

Who Are the Top Gas Flarers?				
	OFFICIAL DATA for 2004		WHAT IMAGERY SHOWS for 2004	
	Country	Billion Cu. M.'s	Country	Billion Cu. M's
1	Nigeria	24.1	Russia	50.7
2	Russia	14.9	Nigeria	23.0
3	Iran	13.3	Iran	11.4
4	Iraq	8.6	Iraq	8.1
5	Angola	6.8	Kazakhstan	5.8
6	Venezuela	5.4	Algeria	5.5
7	Qatar	4.5	Angola	5.2
8	Algeria	4.3	Libya	4.2
9	Indonesia	3.7	Qatar	3.2
10	Eq. Guinea	3.6	Saudi Arabia	3.0
11	USA	2.8	China	2.9
12	Kuwait	2.7	Indonesia	2.9
13	Kazakhstan	2.7	Kuwait	2.6
14	Libya	2.5	Gabon	2.5
15	Azerbaijan	2.5	Oman	2.5
16	Mexico	1.5	North Sea	2.4
17	U.K.	1.6	Venezuela	2.1
18	Brazil	1.5	Uzbekistan	2.1
19	Gabon	1.4	Malaysia	1.7
20	Congo	1.2	Egypt	1.7

Source: World Bank, 2005

Figure 11.

The status quo of the industry has thus far been a dominating position of major conglomerates and IOCs that have been controlling the entire value chain. Although one of the main barriers to entry for new players has been the extremely capital intensive nature of such projects, the technical complexity of these large scale undertakings has also been limiting the ability of niche operators to enter the market. Nevertheless, even if these issues were to be overcome, the proprietary technology required to efficiently run these processes sit with a handful of licence holders. As such, companies like Shell, Sasol, ExxonMobil and Statoil control the GTL process, for example. Independent producers that have access to natural gas, have engineering expertise and access to capital (such as in Russia or Latin America) must work with these license holders to implement GTL projects. This often adds a difficult commercial angle to an otherwise difficult technological process.



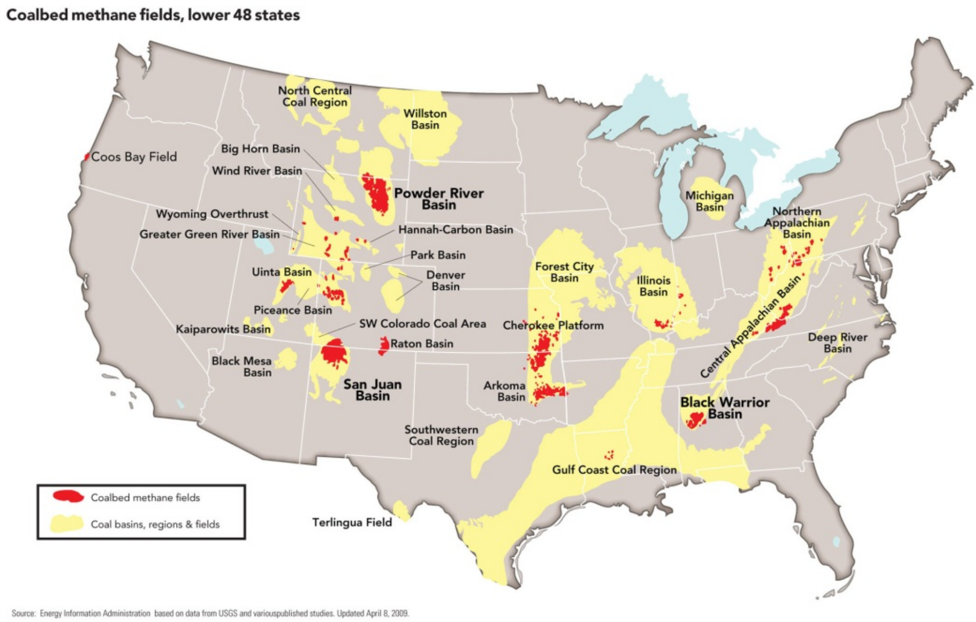
Source: Siemens, 2012

Figure 12.

4. New gasification markets

One of the key ways in which the traditional model outlined above is changing is in the shift to boutique production – small and medium sized projects in which natural gas is used in situ to produce final, value added products. In the last five years, there has been a significant amount of research in reducing the size of gas conversion technology, from micro LNG developed in Australia to micro GTL being developed in America and Asia. This has been, in part, as a result of technological advancement in the field of materials, processing, catalyst and engineering. Two American firms have made significant process in showing the commercial viability of GTL processes without recourse to the proprietary technology of the majors. Rentech and Syntroleum have both developed technology which has seen application outside of the laboratory conditions. As a specific example, Rentech, a medium sized US listed technology company, originally developed GTL technology as part of Texaco, and after a successful spin-out, remained as an independent developer. Whereas traditional GTL technology processes employ the use of cobalt catalysts with fixed bed reactors, Rentech has developed a way to use an iron based catalyst, which is seen as cheaper, and more efficient with a slurry bed reactor. Once capex costs are reduced, the economy of scale element becomes a secondary metric to reach required project rate of returns. Ultra Low Sulphur Diesel (ULSD) manufactured from Rentech production facilities in America has been used in vehicles and aircraft over the last ten years. The US Air Force has used Rentech GTL derived A1 Jet fuel in its aircraft, as part of its security of supply policy.

Boutique application means that stranded or semi-stranded gas reserves of a much smaller size can be successfully monetised. By decreasing required output from 100,000 bpd to 10,000 bpd or less for commercial production, fields of 5 BCM of recoverable reserves open up opportunity for GTL production. A huge market can be identified as CBM (Coal Bed Methane), where large coal deposits in areas such as China, Australia, Indonesia, Mongolia, Ukraine, can begin to utilise gas otherwise unable to reach a value generating market. The United States have significant CBM potential.

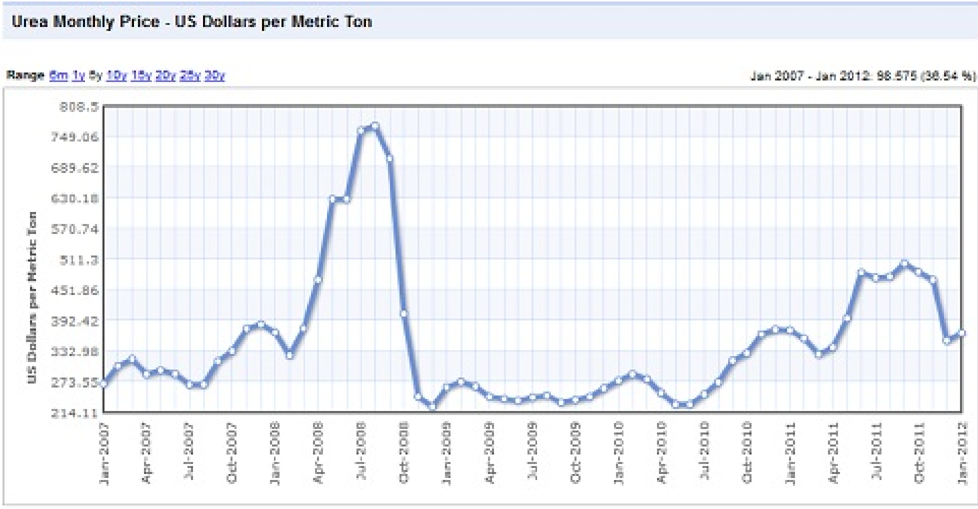


Source: Oil and Gas Journal, 2012

Figure 13.

In normal circumstances, small sized fields that are away from gas infrastructure means that they are stranded, meaning that investment required into pipeline construction render field development uneconomical. Small reactors allow for the production of liquid products that can be stored in canisters and transported by road or rail. For solid products, such as urea, it is possible to build up volumes in any port storage areas and then loaded on to larger vessels (typically 50,000+ tonnes).[10] Urea market is fairly liquid, however, the price volatility means that feedstock costs must be fairly low in order to avoid risks of prolonged loss making.

[10] This operation must be carried out in a fairly timely fashion, as urea has a tendency to degrade over time.

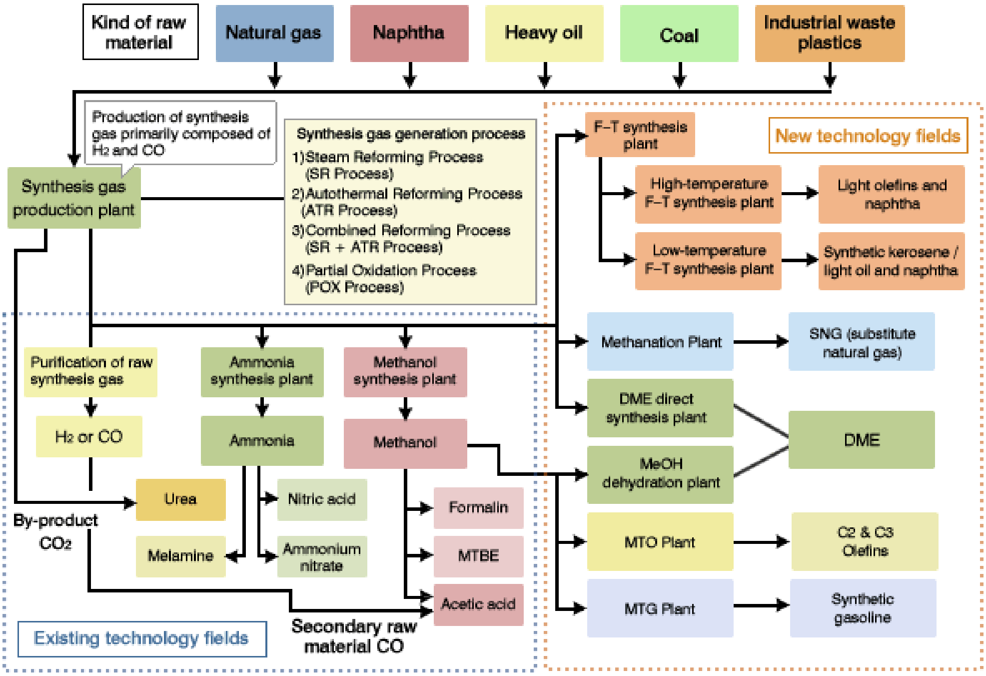


Source: Bloomberg, 2012

Figure 14.

One area which has seen significant attention is the gasification of biomass. This can be done on a micro-scale, meaning the most obvious applications are those of the municipal waste bodies and utilities or operators with large volumes of biomass waste products such as sawmills or sunflower oil producers. Some companies are claiming that they are able to achieve ULSD production in the volumes of 2,200 litres per day from a 10 tonne per day feedstock requirement. Woody biomass is gasified in a two-stage gasifier to produce Syngas with a 2:1 ration of hydrogen to carbon monoxide. This is then processed in a Fischer – Tropsch reactor to produce synthetic diesel fuel. Such small scale, modular application can reroute waste resources traditionally used to produce solid biomass fuels (pellets, briquettes, torrefied biomass etc) that can only be used in power or heat generation to liquid fuels that can be used in the transportation sector, either as blended additives, or for direct internal combustion. The key for a quick uptake of this technology is to reduce capex costs to a level where a 3 – 4 year simple payback can be achieved.

The advantage of the Biomass gasification is that it does not compete with food sources for feedstock, unlike traditional bio-fuels and hence is not party to significant pressure from political commentators and various pressure groups. By-products of agricultural production cycles, or forestry operations can increase efficiency and reduce transport / operations fleet carbon output.



Source: Chiyoda, 2012

Figure 15.

5. Economics of small and mid-sized gasification

The economics of boutique synthetic fuels production have recently shown similar parameters to those of major projects undertaken by IOCs / NOCs. The author was directly involved in a feasibility study undertaken for a medium-sized GTL project, based on non-stranded gas in the Republic of Kazakhstan. The project economics were accepted by the contracted engineers and major, global investment banks focusing on natural resources.

The project entailed a facility with production of 120,000 metric tonnes per year of synthetic fuel (70% ULSD, 20% Naphtha, 10% kerosene), with a feedstock requirement of only 200 MMSCM of natural gas (dry, pipeline quality, high pressure) annually. This can be gas that is received from the gathering system of flared gas collections system, and directed to a processing facility or direct production or even pipeline gas. The price of gas was taken as US $2 per MMBTU.

Capital costs were considered at $150 million (which equates to c. 50,000 /bbl /day), with operational costs estimated at $7 / bbl. Although major operators are able to achieve a lower throughput costs, due to the super premium nature of ULSD and high conversion ratio, project profitability is more sensitive to capital costs. In this case, the project had a 4 year pay back and a 38% IRR.

Investment Analysis

Discount Rate												15.00%
	Years											
Transaction	0	1	2	3	4	5	6	7	8	9	10	11
Cashflow from Operations	8,571	2,143	57,337	60,509	60,598	57,789	57,856	57,571	74,872	74,765	74,996	74,889
Investments	-75,000											
Net Cashflow	-66,429	2,143	57,337	60,509	60,598	57,789	57,856	57,571	74,872	74,765	74,996	74,889
Cumulative Cashflow	-66,429	-57,072	265	60,774	121,373	179,162	237,017	294,588	369,460	444,225	519,221	594,110
Discounted Cashflow	-66,429	1,863	43,355	39,786	34,647	28,732	25,013	21,643	24,476	21,253	18,538	16,097
Net Present Value	-66,429	-57,320	-13,965	$\boxed{25,821}$	60,468	89,199	114,212	135,855	160,331	181,584	200,122	216,218
Internal Rate of Return												37%

Source: Author, Midstream Energy Ltd, 2010

Figure 16.

The key for success of this project, and indeed any boutique application of gas conversion, is the ability to avoid "green-field" development. By placing new facilities on existing infrastructure, such as working refineries or old and abandoned heavy facilities, the capex figure can be kept to a manageable level to give satisfactory project returns. The Former Soviet Union (FSU), for example, has a large number of old chemical facilities that have ceased to operate and with a low cost of domestic gas, become good candidates for boutique GTL or GTC processing. One major advantage is the existence of transport infrastructure, both for the gas via pipeline and product via rail.

6. Impact on policy

Ever since the major discoveries in the US of shale gas, new opportunities have arisen for application of “gas to” technologies. Observers have predicted that the US will become self-sufficient with respect to natural gas, and may become an exporter in the next decade. This has been further compounded by the recent permissions granted to Cheniere Energy for an LNG export terminal. It is incorrect to say that the US will become a net exporter, as it likely there will be imports of natural gas from Canada and some volumes of LNG from further afield. However, Shell has already announced that it is evaluating a large GTL project in the US. The key for such projects is the differential in price between natural gas and high-end products, a situation which reflects the current market in the US very well. Recent prices in the US (Henry Hub Futures) have been hovering at around the US $2 / MMBtu, whilst low sulphur diesel is currently trading at between USD $800 and $1000. If the price of crude oil continues to stay at or about $90+ per bbl, GTL projects become economically viable. This will also have a positive effect on Supply Security concerns, as the more transport fuels can be derived from domestic natural gas, the less dependence there is on oil imports.

When looking at other regions, there are similar advantages for China, as there are large opportunities in the near term for CBM gasification, and in the mid-term for shale gas development. China has announced significant finds of shale gas, and this can help to reduce dependence on oil imports. In fact, China is aware of the strategic disadvantage of having the bulk of the oil imports from the Middle East being shipped via the Malacca Strait. A well planned military operation can block this channel, effectively cutting China off from its oil flow.

African states, especially mature oil development areas such as Nigeria, have been unable to capitalise on the associated gas production, with various methods being undertaken to reduce gas flaring. In situ gas conversion, certainly in the first instance to power, and subsequently to fertiliser production, would be a coherent road map to develop the country’s resources.

In Europe, there is less scope for this application, simply because due to liberalised markets, gas prices do not allow for economic production of other products, except for power generation and commercial and residential sectors. Furthermore, there is simply no spare capacity in the system to divert supplies from power and other sectors to gas processing. Economically, it makes more sense to produce in areas of low cost feedstock and deliver final products to the EU market.

7. Future applications

One of the most advantages characteristics of synthetic fuels or more traditional gas processing products is the ability to utilise these in existing infrastructure without the need for a stock change. The biggest future growth will come from GTL, BTL and CTL processes and environmental concerns will play a role to increase the uptake of these fuels. As more stringent regulation places greater standards on reduced sulphur content in transportation fuels, more ULSD will be used as a blending fuel. Once the technological costs come down the cost curve, and producers will be incentivised to invest in direct GTL technology versus traditional deep refining, pressure will applied to the aviation industry to use synthetic fuels. Aviation is responsible for a major share of Green House Gas (GHG) emissions, and as such is a great potential consumer of synthetic fuels will come from this sector.

8. Conclusion

Natural gas is a versatile raw material that has traditionally been characterised by large complex infrastructure products, requiring full value chain integration. When not used as a fuel for power generation, natural gas has been an invaluable element in many household items and industrial chemicals. Due to the fact that supply and consumption centres have traditionally been separated by large distances, most natural gas projects required capital intensive pipeline construction. The financing of these required the mitigation of risks via long term offtake contracts. This was not the case in the Former Soviet Union, as government central planning directed investment and energy flows according to internal economic planning.

As a result, only large gas bearing basins were developed, with small fields either ignored or considered uneconomic for development. Oil reservoirs that contained a high gas-oil ratio were considered cumbersome in production areas where flaring was unacceptable, and in others where flaring was acceptable, natural gas remained as a nuisance.

With various advancements in technology, reduction in costs and improvements in technical knowhow, as well as economic and environmental conditions, there has been a focus on natural gas as the fuel of choice, ahead of crude oil, in most of the applications. This is likely to drive a trend where the growth in the consumption of gas will overtake oil in the long run, and perhaps become a major contributor to power, transportation and chemical sectors.

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