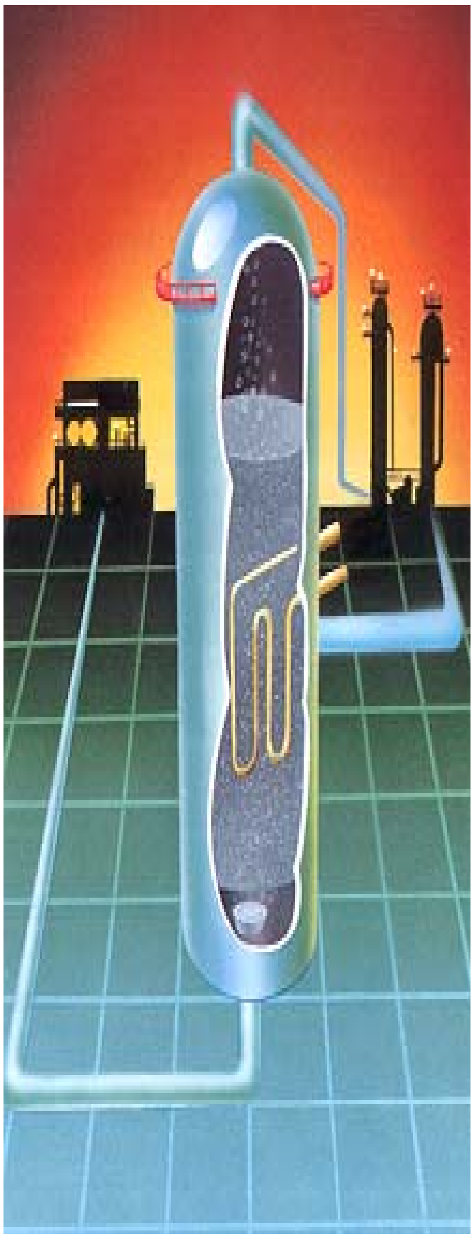
AN ALASKA NORTH SLOPE GTL OPTION – BY ANRTL



EXECUTIVE SUMMARY

ALASKA NORTH SLOPE GTL OPTION

Alaska Natural Resources To Liquids, LLC (ANRTL) was asked to provide the Legislative Budget & Audit Committee with an "Overview of a North Slope Gas To Liquid (GTL) Option". The attached report is not the result of a $ billion engineering study. Rather it is based upon the knowledge gained by the authors, Richard Peterson and Peter Tijm over the last 35 years as they have been involved in the development, design, construction and operation of natural gas based and coal based projects, including GTL and coal to liquids (CTL) projects in Alaska and internationally.

Here are main points we will make:

- It is important for the Legislature to know that there are other options for monetizing North Slope gas than with a gas pipeline, and that GTLs may well result in a much higher wellhead value for gas than a pipeline, more long term jobs for Alaskans and a larger tax base in Alaska.
- A GTL plant would most likely be built in stages, which has several important advantages that we explain. From the standpoint of Alaska employment and economic development the construction would be spread over 14 years. The plant would require a substantial construction workforce, although not as large as that needed for a gas pipeline. The construction workforce would be employed for many more years, however. The operations workforce would be much more substantial than that for a gas pipeline.
- Because the gas conditioning process extracts natural gas liquids before the Fischer-Tropsch (F-T) process converts the remaining methane to high-value products, the liquids remain in Alaska. We believe the liquids can be transported through the TAPS pipeline along with GTL products.
- While a fully-built GTL project could use 4 billion, 5 billion, 6 billion cubic feet of gas/day or more if desired, the plant can be sized to use less gas, leaving gas production that could be transported south through a smaller "bullet" pipeline. As more gas is discovered on the North Slope, more feedstock would become available to a GTL plant and a bullet pipeline.
- In summary, we believe the GTL option gives Alaska high value, economic benefits and flexibility.

Since 1997, ANRTL and its sister company Alaska Natural Gas To Liquids (ANGTL) have been seeking to develop Alaska's natural gas and coal resources by utilizing the Fisher-Tropsch (F-T) process. The F-T process turns carbon bearing materials like natural gas, coal and biomass into ultra clean, non-toxic sulphur and aromatic free transportation fuels. These transportation fuels are 100% compatible with existing crude oil (petroleum-based) transport fuels, transport delivery infrastructure and both today's internal combustion and aircraft engines plus tomorrow's clean burning engines.

ANGTL first proposed building a GTL plant at Prudhoe Bay in 1998. Alaska political leaders and North Slope producers were not keen on the idea. Most wanted a gas pipeline, the political leaders because they did not know much about GTLs and the producers because they did not own commercial GTL technology themselves (although they were at work on GTL research and development). Probably more important, they were the largest refiners on the West Coast and did not relish the idea of competition from environmentally clean GTL fuels. In 2004, ANGTL changed its focus to coal to liquids (CTL) and set its sights on an 80,000 bbl/d CTL plant adjacent to the Cook Inlet Beluga coal field. All of the advantages for an Alaska GTL plant on the North Slope hold true for a CTL plant in the Cook Inlet with the added advantage that substantial employment would benefit the Southcentral economy and the waste heat from the F-T process could help generate low cost power for the railbelt grid. Also, CO_2 sequestering and use of CO_2 could add millions of barrels of oil recovery to Cook Inlet fields. With the U.S. West Coast market, primarily California, as the market of choice, there are benefits to an Alaska location whether the project is a GTL plant on the North Slope a CTL plant on the Cook Inlet, or both.

The world has changed since 1998. There is now more interest in alternative fuel projects like GTL and CTL with the emergence of China and India as world energy consumers. In response, major oil companies are developing GTL and CTL projects around the world. In 2004/05 ConocoPhillips and ExxonMobil signed agreements to build 160,000 bb/day and 150,000 bbl/day GTL plants in Qatar. They would not have made these commitments if they did not believe in GTLs and possess the skills to build world-scale GTL plants. Shell Oil, a new player in Alaska, has a GTL plant in Malaysia and is building a 140,000 bbl/d GTL plant in Qatar as well as a CTL plant in China. Chevron, Sasol's world wide GTL partner, is building a GTL plant in Nigeria and stands ready to commence a 170,000 bbl/d GTL expansion with Sasol in Qatar. ExxonMobil has a well-developed GTL technology and has studied its use on the North Slope. Clearly, the North Slope majors possess all the skills necessary to build GTL plants in Alaska.

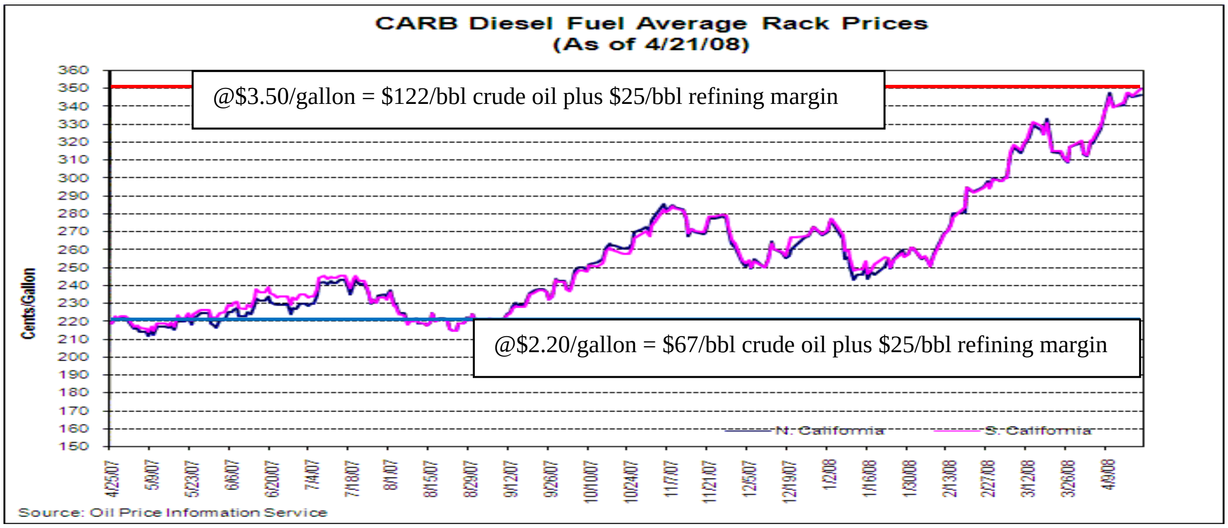
Based upon our experience, recommendations and input from other pipeline companies, engineering companies and technology providers such as Sasol and Shell there is no doubt that a GTL program will work on the North Slope. Admittedly, its remote location would be difficult for a "green-field" program (a plant in an undeveloped area) but the infrastructure now built on the North Slope offers significant advantages. Moving GTL products from the North Slope to market would be a daunting prospect if it were not for the underutilized TAPS oil line. Without question, TAPS can be modified to carry not only GTL products but a full slate of natural gas liquid products from Prudhoe Bay to Valdez. Not only do you keep these valuable products in the Alaska, you also increase the throughput of TAPS, lowering operating costs per barrel transported. The only environmental challenge for GTL plants to overcome is what to do with CO_2 that comes from the F-T manufacturing process. Again, a North Slope location has the answer – one of the largest sinks in the world for sequestering CO_2 with the added advantage of recovering additional crude oil through an EOR program.

A $40 billion dollar GTL program is not for the faint of heart. This is a 2007 number based on actual construction costs of large GTL plants escalated with inflation through 2022 for a phased building of a 450,000 bbl/d GTL plant. It is a realistic number based upon 2007/08 GTL plant construction adjusted for a North Slope Alaska location.

Building a North Slope GTL program in phases has several advantages over a "once off" construction, a one-time project. It will allow more Alaskans to participate in the design, fabrication and construction process, with all of the capital located in Alaska and all of the value added products produced in and sold from Alaska. Phased building will allow for a closer look at the potential impact of taking recycled gas from the oil reservoir, and the project will benefit from advances in technology over time.

Some readers will say "but the refiners in the U.S. claim they are losing money – Why would anyone want to build a new refinery. The fact is refiners are struggling in 2008 because the vast majority of the fuel they produce is gasoline. In the face of record pump prices, gasoline inventories are raising, causing the pump price to drop – margins to shrink. This is not the case with diesel. Many U.S. refiners now wish they went the way of their European counterparts: maximizing diesel and minimizing gasoline output. A North Slope GTL plant will produce 80% or better middle distillates (diesel). Still some may say "why would I want to use diesel", it's more expensive. Yes diesel now sells for 16% more than regular gasoline but a diesel engine gets between 20% to 30% better mileage so, in the end, a diesel vehicle has a lower fuel cost per mile.

Other readers may say the GTL process is not efficient with only 65% of the energy contained in the natural gas reaching the end market in the form of transportation fuels. Like any manufacturing process that "adds value" to its products, the transportation fuel resulting from a GTL plant have a high value. Also of importance is that the "lost" 35% really isn't lost. It is captured as waste heat and is used to generate electricity, heat buildings and run other processes that need heat – saving valuable natural gas for other purposes.



One may ask "what is the value of F-T products in the target market". For the moment we will look at the value of diesel in the California market which represents approximately 80% of the GTL plant output. The chart above shows that on the 21st of April, diesel was selling for $3.50/gallon at the refinery tailgate. On a Btu equivalent basis natural gas would be selling for $26.90/MMBtu at the city gate. At $2.20/gallon ($67/bbl crude oil) the natural gas equivalent price would be $16.9/MMBtu. A lower excise tax rate common for natural gas used in transport if applied to GTLs will add an additional $2.40/MMBtu to the value of F-T diesel.

We conclude that in today's market, a North Slope GTL plant producing diesel fuels represents a high value for Alaska natural gas and for Alaskans.

It's time to think outside the box and not from its centre. The oil majors, operate the largest oil field in the U.S. and the largest gas processing plant in the world, both successfully. They have shown that the once forbidding North Slope of the 1960's can be tamed.

The authors hope that this report will show the reader that GTLs and specifically a North Slope GTL program can provide the State with far more options than it was aware of as it evaluates the best way to develop the North Slope Natural Gas Reserves.

We have divided the Overview of a North Slope GTL Option into 15 Sections. They are:

1. Executive Summary
2. Introduction to GTLs
3. F-T Technology
4. U.S. Oil and Gas Overview
5. GTL Products in the Market
6. Environmental
7. U.S. West Coast Transportation Fuels Market
8. Federal Support for GTLs
9. Economics of a North Slope GTL Option
10. Benefits of GTLs for North Slope Operations
11. Transport of F-T Products on TAPS
12. Benefits of Phased GTL Development
13. GTL vs. Natural Gas (Value vs. Efficiency)

Sections 14 and 15 are biographies of the Authors.

Below are short summaries of each of the Sections of this Report that will aid the reader as he or she evaluates options for the State of Alaska's development of its North Slope gas reserves.

Section 2 Introduction to GTLs

In the last few decades natural gas has become an increasingly important energy resource for two reasons:

a) The frantic drilling for oil after the oil crises of the 1970s revealed huge natural gas reserves, making it the second largest hydrocarbon resource in the world. By 2010, it may be the largest.

b) Technology developments now allow us to economically convert natural gas into our familiar liquid hydrocarbons and for the (national) oil companies to monetize stranded gas. Hence, from a technology standpoint "stranded gas" is a thing of the past.

In recent years the traditional, energy content-based, coupling between crude oil prices and natural gas prices has vanished. We can only guess, at this point in time, as to the reasons for this disparity: is it pure speculation on the "commodity" crude oil market, while the more difficult to transport gas remains less affected and more stable? Certainly on an energy basis the disparity is flagrant.

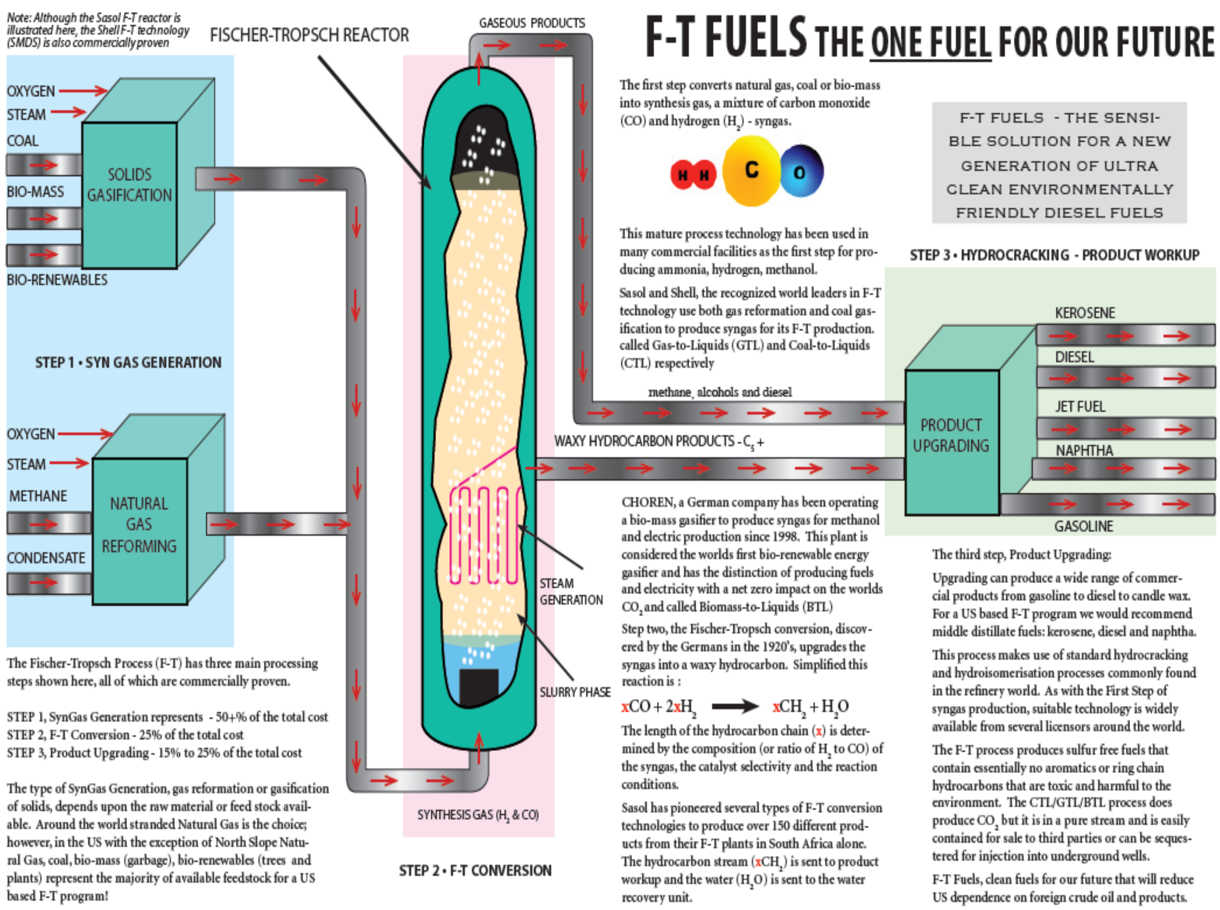
As an example we take an early April 2008 wholesale rack market price for diesel in California at U.S. $3.30/gallon. On a pure energy basis, with diesel at 130,000 btu/gallon the equivalent natural gas price would be U.S. $25.40/mcf, versus the reality of the market showing a first quarter 2008 Henry Hub price of U.S. $8.03, a third of the value of diesel. As a result, interest in natural gas conversion is at an all time high and GTL projects demonstrate profitability, which they rarely enjoyed before.

For this Report we will focus on a fully integrated GTL facility on the North Slope, capable of producing directly marketable finished transportation fuel products, to provide the maximum market penetration and product value for the plant owner and the State of Alaska.

Section 3 F-T Technology

F-T is not a new technology. It has been around since the early 1900's and in commercial use in large scale plants since the early 1950s. The historical development of the Fischer-Tropsch synthesis is discussed in more detail in Section 3. Based on chemistry with carbon monoxide and hydrogen derived from town- and coke oven gas the synthesis of liquid hydrocarbons was conceived by Franz Fischer and Hans Tropsch in Germany in 1923. Prompted by abundant remote "stranded" gas reserves and need for environmentally benign transportation fuels, further development of world scale gas to liquids facilities began in the late 1970's.

The complete process has three distinct steps: syngas generation, Fischer-Tropsch synthesis and product-upgrading. The Fischer-Tropsch synthesis has been developed in two versions: the high temperature version (more suited for production of chemicals) and the low temperature version (suited for production of liquid transportation fuels). For the Alaska North Slope this study focuses on the low temperature version. The various stages of the process, operating parameters and reactor technology are discussed in more detail in Section 3. The diagram below illustrates the three basic steps in the GTL/CTL/BTL process. The only difference between a gas, coal or biomass fed process is how we generate the syn-gas in step 1, otherwise the process is identical.



The low temperature GTL technology is currently used by the major oil companies, in joint ventures with national oil companies - the new dominant players in the oil and gas industry,- as tools to monetize natural gas and put it on the books as "replacement oil". At this point in time there are only two companies worldwide that have operating commercial scale low temperature GTL plants, Sasol with a 34,000 bbl/d plant in Qatar (a 170,000 bbl/d expansion is on hold) and Shell, with a 15,000 bbl/d plant in Malaysia and a 140,000 bbl/d plant under construction in Qatar. While each company's technology is financeable in today's high cost energy market, both have indicated that they only bring their F-T technology to locations where they also participate as an equity owner. Additional players in the market of the near future are ConocoPhillips and ExxonMobil, who respectively committed to build 160,000 bbl/d and 150,000 bbl/d GTL plants in Qatar.

Several of the key players, their R&D, pilot plants as well as industrial activities are individually discussed in detail in Section 3. There is ample room in the hydrocarbon fuels (and specialty) markets for all of these competitors to co-exist.

Section 4 U.S. Oil and Gas Overview

The relationship between natural gas and crude oil is analyzed in more detail in Section 4. We show that while most people believe natural gas is in short supply in the U.S., domestic production and imports from Canada are adequate to meet domestic demand. The situation with oil is more critical. Far more crude oil is imported into the U.S. than natural gas. In addition, and probably more important to the price at the fuel pump, is a lack of about 3 million barrels per day of domestic refining capacity. Until recently there was no incentive for U.S. refiners to build additional capacity. Refiners simply passed through the ever increasing costs of feedstock/crude oil and in 2007 enjoyed a comfortable refinery margin, in many cases exceeding $25/bbl. Today gasoline prices are actually lower than would normally be the case due to the dumping of surplus gasoline imported from Europe where the demand for diesel is so much higher. This explains why diesel fuel at the pump is currently so much higher than gasoline.

With the current price increases of crude oil, driven partly by speculation, the majority of oil based commodities that can switch have changed over to natural gas. Yet, the U.S. supply and demand outlook for natural gas suggests that there is still ample volume available, leading to 1) a decline/stop in U.S. Liquefied Natural Gas (LNG) imports because as other nations are willing to pay more for the LNG, and 2) loss of the traditional parity in the U.S. between crude oil and natural gas.

We conclude that, whatever volume of natural gas is imported in the lower 48, the dependency of imported crude oil and/finished transportation product will not be eliminated. Also, due to this oil/gas disparity, comparison of the current natural gas market prices with the California ultra low sulfur diesel price shows that, on an energy equivalent basis, there is much greater return for Alaska from marketing GTL products compared with selling natural gas. Should the energy equivalent parity between crude oil based transportation products and natural gas be re-established, a gas price increase of some 250% would be needed, something, which is considered not likely.

While the relationship between natural gas and crude oil has changed in recent years, the economic relationship between motor gasoline and diesel has eclipsed that of crude oil and natural gas. The U.S. requirement for ultra-low sulfur diesel and the very large demands for diesel in Europe have added 40¢ to 80¢ per gallon to the value of diesel in comparison to that of gasoline. Today in the U.S., it is common for motorists to pay a 50¢-70¢ per gallon premium for diesel over regular gasoline – at least $29/bbl more than the historical relationship between gasoline and diesel. With Europe and the rest of the world using diesel because of its 20% to 30% better mileage performance we do not see this premium changing until more diesel fuel can be manufactured.

We believe that the current relationship between gasoline and diesel will remain, providing a long-term $20/bbl or greater premium for F-T diesel than historic numbers would show. Couple this with the break in energy price parity between crude oil and natural gas and F-T diesel from a North Slope GTL plant or ANRTL's proposed Cook Inlet CTL plant could net back even more value than exporting natural gas and certainly coal.

Section 5 GTL Products in the Market

The market for GTL products can be split up into transportation fuels and specialty markets. In the fuel markets GTL diesel is the most important component, followed by GTL kerosene, which enjoys an increasing popularity as jet engine fuel. Many factors will drive GTL technology introduction into the US. Market values, coupled with demand for incremental diesel and a desire for oil import independence are three of the key components that would make this happen.

Without question the market for F-T diesel in the U.S. is unlimited. The current average wholesale price for diesel in the U.S. will support a Sasol/Shell-type GTL plant without any government support, even with GTL capital expenditure (CAPEX) of about $40 billion for a 450,000 bbl/d plant. However, financing on the basis of $120 per barrel crude oil is impossible because the financial community will always be cautious and factor in the possibility of a price decline. In comparison, however, even these high costs correspond to an oil replacement cost of less than $13 per barrel, a level which already today is attained in many conventional Gulf of Mexico oil projects. As environmental laws drive the need for lower emissions, cleaner F-T diesel will sell for a premium as a blend stock. With a demonstrated sustainability of a GTL supply, municipal bus fleets and large corporation diesel truck fleets will pay a premium for F-T diesel to avoid costly infrastructure required for compressed natural gas (CNG). The biggest hurdle for GTL program is market acceptance of the diesel engine and a new fuel, F-T diesel. Once demonstrated, an F-T GTL program will quickly gain more and more market share, Congressional support and public awareness. The U.S. Air Force has just completed extensive studies on F-T jet fuel and plans to have half of its fuel requirements supplied by F-T jet fuel by 2016. Unless we build F-T (GTL and CTL) plants in the U.S, this demand will be met with more imported fuels.

Putting the US market for motor fuels in perspective, currently the U.S. consumes approximately 13 million barrels (500 million gallons) of motor fuels per day. Approximately 4 million barrels of this is middle distillate, of which 2.4 million bbl/d is on-road diesel. There is an increasingly diminishing appetite for gas-guzzling heavier (SUV) vehicles and increasing hunger for fuel efficient vehicles, especially powered by diesel. With the advent of ultra-low-sulphur (ULS) diesel in the third quarter of 2006, we expect to see a gradual shift from gasoline to diesel as the U.S. legislates higher CAFÉ standards for its fleets.

California already has no distinction between on road and off road diesel (for ultra-low sulphur) today. By 2010 all on-road and off-road (marine and train) diesel will be in the same quality category so in effect by 2010 diesel demand will be 4 million barrels or 168 million gallons per day. (This assumes no increase in demand from today). As a result a 450,000 bbl/d GTL plant on the Alaska North Slope will hardly make a dent in the market and enjoy continued price stability.

Section 6 Environmental

The GTL process selection is made to minimize the impact on the local environment. The largest effluent stream is water, which is recycled to the process units to the greatest extent possible. Excess water can be used for enhanced oil recovery through oil well water floods. Various adsorbents and catalyst are used in the plant, all of which can be recycled using metal reclaiming and/or metal smelting.

Plant and product specific emissions (CO_2, SO_2, NO_x, CO, hydrocarbons and particulate matter) are easily handled with existing technology. The GTL process is on a par, if not better, than crude oil refinery systems, in terms of CO_2 emissions, using either the Life Cycle Analysis or the "Well to Wheel" method. The F-T process requires the capture of CO_2 before it can enter the F-T reactor. This captured relatively pure CO_2 is easily sequestered and/or available for enhanced oil recovery programs such as those utilized at Prudhoe Bay.

GTL diesel has convincingly demonstrated reductions in tail pipe gas emissions ranging from 8% to 38%. GTL fuels used in concert with new engine technologies will only reduce emissions further.

Section 7 U.S. West Coast Transportation Fuels Market

The U.S. West Coast transportation fuels market is arguably the best market for F-T fuels in the world, consuming over 3 million barrels per day of some of the cleanest transport fuels that are available. California, the 10th largest economy in the world, accounts for more than 63% of this volume and has the highest wholesale fuel costs. Since the California wholesale price is driven by the highest possible fuel quality, F-T fuels fit right into this market.

Should a U.S. West Coast/Alaska GTL market development require any political clout, it is comfortable to know that from a political level one out of five representatives in Congress represent Washington, Oregon, Idaho, Nevada, Arizona and California.

Six factors are important to the success of an Alaska GTL or Coal-to-Liquids program.

- A market that is growing at a rate that will exceed refining capacity additions,
- A market place that values ultra-clean fuels, especially low aromatic diesels,
- An environmentally active population that is willing to not only support clean fuels but to pay for them,
- Refining centers that are on the water so that F-T fuels can be delivered to the beginning of the value chain and,
- A place to sequester CO_2 derived from the F-T process at the source of manufacture,
- A market that represents a substantial number of members in Congress.

California middle distillate fuels market, the target market for an Alaska F-T program is the largest, volume wise, in the U.S. and has the highest quality standards of any market in the world. This accounts for two reasons why the California market has some of the highest fuel prices in the world. Considering a recent, March 2008 California CARB diesel refinery-gate price of \$3.20/gallon (the CARB price was over \$3.80/gallon mid May 2008) we expect to see a North Slope GTL facility able to pay a netback price over \$9.00/mcf for natural gas delivered to the GTL plant inlet.

If the North Slope GTL plant was built in phases, the netback number would be higher. We have assumed no reduction in costs per barrel delivered to operate TAPS with the extra GTL and natural gas liquids (NGL) products batched down the oil line.

Section 8 Federal Support for GTLs

There are many different forms of federal support for alternative or new fuel programs developed in the U.S. Congress has historically provided support in the form of loan guarantees, co-funding, accelerated depreciation, mandating requirements to use a specific fuel, emission requirements that can only be met through the use of alternative fuels, energy credits and the most common, lower excise taxes on specific transportation fuels. We look at two of the most common: lower excise taxes and energy credits.

The existing lower excise taxes for natural gas used in a diesel engine should apply to a natural gas based F-T plant on the North Slope. If this is realized, the North Slope GTL plant would see a \$13/bbl benefit or increase in netback.

ANGTL also believes that Energy Credits, granted in the 2005 Transportation Bill to coal and biomass based F-T plants, could easily apply to a natural gas based F-T plant. If true, then the Alaska GTL plant would receive \$21/bbl of net back price support or \$13/bbl with the either of the energy credits or lower excise tax. In addition, the \$18 billion loan guarantee for the Alaska Gas Line might apply, with a tweak of federal legislation to a GTL option so long as the transportation fuels are delivered to domestic markets. Finally, the National Defense Council Foundation report clearly shows the hidden costs of importing crude oil and transportation products.

In 2003, the NDCF said, "*It would be difficult to imagine the advent of any commodity that has had the impact of oil on virtually every area of human endeavor. From transportation to medicine to agriculture to materials, petroleum-derived products have had a profound impact. Moreover, these products have been readily available at bargain-basement prices through most of our history." …… "Yet, the price for a gallon of gasoline a consumer pays at the pump is in fact only a fraction of the real cost of the fuel. It does not reflect the enormous burden of external costs that arise from the military, economic, environmental and health outlays directly resulting from our dependence on foreign oil. If our nation is to make rational policy decisions regarding the rising tide of imports, it is essential that decision-makers fully understand what these costs are, and how they are incurred*".

The Alaska delegation relied upon this report in part in marshalling support for the \$18 billion loan guarantee. The facts contained in this report clearly show that Federal support for a domestic GTL, CTL or BTL program are justified far beyond the 31¢ to 50¢ per gallon we are discussing herein.

We would point out that there are more than enough federal support programs on the books to improve the economics of a North Slope GTL option. Some may require simple changes from a loan guarantee for the Alaska gas line to an Alaska GTL option, some may take an Internal Revenue Service ruling saying that GTL-based F-T diesel is the same as Compressed Natural Gas (CNG) when used as a transportation fuel.

The bottom line is that the U.S. needs domestic transportation fuels and especially domestic refinery capacity more than it needs additional natural gas. Because a North Slope GTL program fits this need, Congress should be supportive as it fills a national need, not just Alaska.

Section 9 Economics of a North Slope GTL Option

We have evaluated a 450,000 bbl/d North Slope GTL option under two different scenarios: (1), construction in one large scale project beginning in 2009; and (2) a phased construction consisting of five (5) 90,000 bbl/d modules beginning in 2009 and concluding in 2022. The total capital cost, approximately $40 billion is about the same for each case due to our projected cost of inflation of 3% per year.

While the initial cost per installed barrel of capacity was determined for the recently completed 34,000 bbl/d Sasol ORYX GTL plant in Qatar, current demands for workers and materials has escalated the projected costs from $35,000 per daily barrel to $60,000 per daily barrel. Such has been validated for modules of 70,000-80,000 bbl/d capacity. The modular approach has been used by Shell in Qatar for their Pearl GTL project and within reason makes sense for any application on the Alaska North Slope.

The $60,000/daily barrel cost is the result of the tremendous increases in cost for new energy projects across the world. It is generally accepted in the energy world that such escalation is an over-reaction forced by constraints in materials availability and engineering capacity. It is felt that this escalation will re-dress itself in the next few years; however, it is unlikely that we will return to the $25,000/daily barrel we had seen for the then proposed Sasol/QPC ORYX project in 2002. A level of $50,000/ daily barrel is projected as a likely future scenario.

For a preliminary cost estimate, taking into account the location and environmental conditions on the North Slope, we have applied a location factor of 1.5 x $50,000/installed barrel of capacity, implying the use of $75,000 per daily barrel. Thus a 450,000 bbl/d facility would cost an estimated U.S. $33.8 billion on a 2007 dollar basis. Assuming a modular construction of one of five 90,000 bbl/d units every other year after 2014, the first product from module # 1 some 6 years from today and an annual inflation of 3 % the escalated total investment upon completion of the project in year 2022 would amount to some **U.S. $40.5 billion**.

There are advantages to phased construction that are covered in more detail in Section 12.

We estimate that based upon a 25% equity investment with a 20% Internal Rate of Return (IRR), a 20-year bank loan at 7.5%, a $7/bbl transport cost from Prudhoe Bay to California markets and wholesale diesel prices in the $3.20/gallon range, that the net back to North Slope gas suppliers at the GTL plant inlet will be in the $9.10/MMBtu range.

We did not include the economic advantages of a phased construction for Alaska business, the fact that much of the capital expenditure will be in Alaska, that a GTL plant can be a net exporter of energy, i.e. can be designed to produce excess energy to operate other North Slope facilities, the TAPS line would carry more fluids and operate more efficiently, with a lower tariff, nor did we assume any price advantage for shipping NGLs down the TAPS line to Valdez over the sale of the same NGLs in central Alberta.

The North Slope GTL option would be in the first phase of its evaluation, ***I Preliminary Feasibility Study***. *(See chart on page 2 Section 9 for the details*). Normally we would say that the costs estimates, estimated at this point in its evaluation are a +- 40%. However, with the recent building of the Sasol ORYX GTL plant and the start of engineering of the Shell Pearl GTL facility we believe that the cost estimates used herein are more likely to be at the + 20% level and that further evaluation will result in a lower cost estimate. When the reader sees that the Alaska GTL plant is estimated to cost 300% more per installed barrel of capacity than the just completed Sasol ORYX GTL plant we believe our statement can be supported.

Regarding availability of technology, we note that:

- two of the North Slope gas owners, ConocoPhillips and ExxonMobil have agreed to build world scale GTL plants in Qatar;
- Chevron, Sasol's world wide GTL partner is a major player in the Point Thompson field; and
- BP is working with Statoil to develop barge mounted GTL plants

Hence the technical knowhow is there to develop an economic North Slope GTL program.

Section 10 Benefits of GTLs for North Slope Operations

The benefit of a GTL facility on Alaska's North Slope is not only limited to the greater revenues which will be attributable to the state of Alaska by realization of the sales of predominantly diesel fuel over the sales of natural gas. There are important secondary benefits arising from the plant. Among those are:

1) The ability to convert not only methane, but any carbon bearing molecule, like ethane, propane, butane and partially, CO_2 into synthetic transportation fuels. This gives the North Slope GTL plant operator a tool to maximize his revenue, depending on market conditions.
2) The ability to convert the plants and adjacent facilities in to an energy independent unity, though recovery of F-T process heat and off-gases.
3) The use of some fraction of the hydrocarbons produced in the North Slope GTL facility as biodegradable, synthetic drilling fluids, with the potential to bring the oil drilling costs down.
4) The ability to use the Fischer-Tropsch process effluent water beneficially for enhanced oil recovery.
5) The ability to perform the reverse water gas shift reaction, which allows effective conversion of CO_2 in liquid hydrocarbons as well as the ability to recover CO_2 very effectively from the syn-gas.
6) The use of CO_2 as well as the abundantly available nitrogen from the air separation plants for EOR.
7) The manpower loading until 2024 for a North Slope project of up to 900 operations people, while thereafter a steady operating manpower of between 600 to 900 people seems reasonable. Such could provide for a long term stable employment, which would entail through the economic spending multiplier an estimated U.S. $2 to $3 billion economic boost for the area and region, hence, an important economic development.

Section 11 Transport of F-T Products on TAPS

In 1998, when ANGTL first proposed a GTL option for Prudhoe Bay the question most asked was, “how are you going to get the products to market?” Our reply was “batching the products down TAPS in pig trains to Valdez where the different products would be segregated into tanks for loading on tankers supplying the West Coast markets and refining centers”. The immediate response was “can’t be done! … you can’t put crude oil and products in the same pipeline.”

Experience has shown that this is not true.

One of the advantages of a North Slope GTL option is that TAPS line can remain viable for moving crude oil produced on the North Slope to Valdez for 50 to 100 or more years. GTLs can provide the minimum throughput volumes to keep the TAPS line flowing even if North Slope crude oil production drops below 300,000-350,000 bbl/d. Incremental GTLs and NGLs will help lower the TAPS tariff resulting in a higher netback price and a higher revenue stream to the State.

There is no question that the TAPS line can be operated as a dual/multi-products pipeline. Explorer Pipeline, owned by several major oil companies has successfully operated a 1,400 mile large diameter pipeline carrying a full slate of refined products and crude oil. In fact the Explorer Pipeline model is used in many pipelines in operation today. Explorer Pipeline has offered to bring their expertise to Alaska to assist with the design and conversion of TAPS.

Once TAPS is modified to carry both crude oil and products, the currently recycled gas stream can be processed to extract NGL’s for batching to Valdez. This allows for the recovery of this revenue stream within a few years, before a GTL plant could be on line or a gas pipeline to the lower 48 could be built. Further, it is our opinion that the market for North Slope NGLs will be considerably higher at Valdez than at the ACEO hub in central Alberta.

The interior of Alaska operates on a liquid energy economy. Batching products down TAPS will provide Interior Alaska with the opportunity to receive lower cost fuels at new delivery points along the pipeline without having to replace their existing energy infrastructure.

Modifying the TAPS line to batch crude oil and products will eliminate the need to transport liquids in the AGIA gas line. Thus if a gas line option is chosen modifying TAPS will reduce the cost of the gas pipeline and make its operation easier.

It goes without saying that the overview on batching in TAPS provided here is certainly not the result of a detailed engineering study. The biggest obstacle to a successful transition would be **reluctance to change**, common in so many businesses that have been operating under one set of conditions for 20 or 30 years.

Section 12 Benefits of Phased GTL Development

The state of Alaska is interested in receiving the highest value for its resource while creating the best long term opportunities for all of its citizens. Is withdrawing natural gas from the North Slope reservoirs at a high rate better or worse for the ultimate recovery of oil and the States’ treasury? Certainly the U.S. energy market can use the natural gas, or GTL products; but is all out short term development the best thing for the State or is phased long term development better?

It is not our intent to provide a definitive answer to these questions. Rather, we will outline some issues and let the state debate their relevance as they evaluate the pros and cons of a phased GTL development program or even GTL plants versus a gas pipeline to the lower 48.

Here are some points to consider:

1. Less natural gas is removed from the oil field in the early years so that reservoir engineers can evaluate the impact of selling natural gas on the ultimate recovery of crude oil.
2. A work force utilized for a longer period of time results in long term job growth and permanent residents.
3. Alaskan businesses can expand their capabilities to meet the long term needs of GTL plant construction and have the time to recover their capital investment.
4. Less capital is required up-front to build a massive GTL plant with cash flow from the earlier modules helping finance later modules.
5. Slow or speed the delivery of later modules as events dictate creating less risk to the equity owner and investors.
6. TAPS can be modified to batch immediately and 100% of the NGLs from gas processing can be delivered to Valdez before the first GTL plant is on line or the gas line is built.
7. Currently we are in a peak demand for energy and energy projects, so there is a premium to be paid to build energy projects across the world. As a result costs are doubling even tripling as $120 per barrel oil prices can afford these inflated costs. With time, engineering companies, construction companies and manufacturing companies will expand to meet demand and these costs will come down.
8. Next generation plants are usually more efficient and at times will have a lower capital costs as process engineers constantly improve plants with time and technology. Next generation modules, especially on the North Slope, will be more efficient and/or cost less than the previous one. Thus, a long-term schedule of GTL plant construction will see greater efficiencies and cost improvements over time.

Section 13 GTL vs. Natural Gas (Value vs. Efficiency)

One of the biggest arguments you hear from those opposed to GTLs is that the process is inefficient. It is true that only about 65% of the energy contained in the natural gas feedstock ends up in the transportation fuels delivered to the market. Like any manufacturing process that "adds value" to the product, the resulting transportation fuel has a higher market value. Also of importance is that the "lost" 35% really isn't lost. It is captured as waste heat and is used to generate electricity, heat buildings and run other processes that need heat. This saves natural gas currently used for these purposes for more valuable uses.

With advances in F-T technology currently in the lab we expect to see conversion efficiencies approach 75% within the next 3 to 5 years. The bottom line is what is more important? Conversion efficiency or market value? The answer is not always apparent. Consider that when we ship natural gas either via a pipeline or by LNG to the market different conversion efficiencies apply. For home heating 80% to 90% is common for the best technology. Gas-fired electric power generation is 55% under the best of circumstances. Transportation fuel conversions aren't any better, but the value of the transportation fuel in the market place is considerably higher on a Btu basis than that of natural gas.

This was difficult to comprehend in 1998 when we first presented the North Slope GTL option to the state of Alaska. We designed the graphic flyer below to show the point. It resolved the issue in many minds then and we believe it can do so again today.

The illustration below provides one with a rational way to understand value vs efficiency.

ANRTL

GTL vs LNG

VALUE ($) VS EFFICIENCY

IS THE LNG PROCESS MORE EFFICIENT - WITH 80 % OF THE WELL HEAD ENERGY REACHING THE MARKET ?
IS THE GTL PROCESS LESS EFFICIENT - WITH 65 % OF THE WELL HEAD ENERGY REACHING THE MARKET ?

TECHNICALLY, LNG IS A MORE EFFICIENT PROCESS IF YOU JUST LOOK AT DELIVERED ENERGY TO THE MARKET
IT IS HOWEVER TOTALLY FALSE IF YOU LOOK AT THE VALUE ($) OF THE DELIVERED ENERGY IN THE MARKET

LNG BEGINS LIFE AS NATURAL GAS AND ENDS LIFE AS NATURAL GAS

GTL BEGINS LIFE AS NATURAL GAS AND ENDS LIFE AS A REFINED PRODUCT SUCH AS DIESEL

WHILE BOTH ARE CARBON BASED, THEIR VALUES ($) ARE TOTALLY DIFFERENT

AS AN EXAMPLE:
A LUMP OF COAL AND A DIAMOND ARE BOTH CARBON BASED. UNDER TREMENDOUS PRESSURE AND HEAT (A MANUFACTURING PROCESS), A LUMP OF COAL CAN BECOME A DIAMOND. WHICH HAS MORE VALUE, A LUMP OF COAL OR A DIAMOND? DOES IT MATTER THAT A DIAMOND IS A FRACTION OF THE SIZE OR WEIGHT OF THE ORIGINAL LUMP OF COAL?

IF GTL PRODUCED DIESEL IS MORE VALUABLE THAN LNG DERIVED NATURAL GAS SHOULD YOU CARE IF THE GTL PROCESS IS LESS EFFICIENT IN CONVERTING ENERGY SO LONG AS THE VALUE RECEIVED FOR THE ORIGINAL ENERGY IS GREATER.

WHICH WOULD YOU PREFER ?

A LUMP OF COAL

OR A DIAMOND

LNG PRODUCED NATURAL GAS **OR GTL PRODUCED DIESEL**

THE CHOICE SHOULD BE SIMPLE
GO FOR THE HIGHER NETBACK VALUE ($)

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ANRTL is responsible for this report and its contents. Richard Peterson is the principal owner of ANRTL with Peter Tijm having an ownership position. Mr. Tijm also runs a successful consulting business, PV Enterprises, Inc.

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2 INTRODUCTION TO GAS TO LIQUIDS (GTL)

2.1 Summary/Conclusions

In the last decades natural gas has become an increasingly important energy resource for two reasons:

a) the frantic drilling for oil after the oil crises of the 1970s revealed huge natural gas reserves, making it the second largest hydrocarbon resource in the world.

b) technology developments now allow us to economically convert natural gas into our familiar liquid hydrocarbons and for the (national) oil companies to monetize stranded gas and put it on their books. Hence, from a technology standpoint "stranded gas" is a thing of the past.

In recent years the traditional, energy content-based, coupling between crude oil prices and natural gas prices has vanished. We can only guess, at this point in time, as to the reasons for this disparity: is it pure speculation on the "commodity" crude oil market, while the more difficult to transport gas remains less affected and more stable? Certainly on an energy basis the disparity is flagrant.

As an example we take the current market price for diesel in California at U.S. $3.30/gallon.

On a pure energy basis, with diesel at 130,000 btu/gallon the equivalent natural gas price would be U.S. $25.40/mcf, versus the reality of the market showing a first quarter 2008 Henry Hub price of U.S. $8.03/mcf, a third of its value as diesel. As a result, interest in natural gas conversion is at an all time high and GTL projects demonstrate profitability, which they have never enjoyed before.

For this report we will focus on a fully integrated GTL facility on the North Slope, capable of producing directly marketable finished fuel products, to provide the maximum market penetration and product value for the plant owner and the State of Alaska.

2.2 Gas-to-Liquids in Perspective

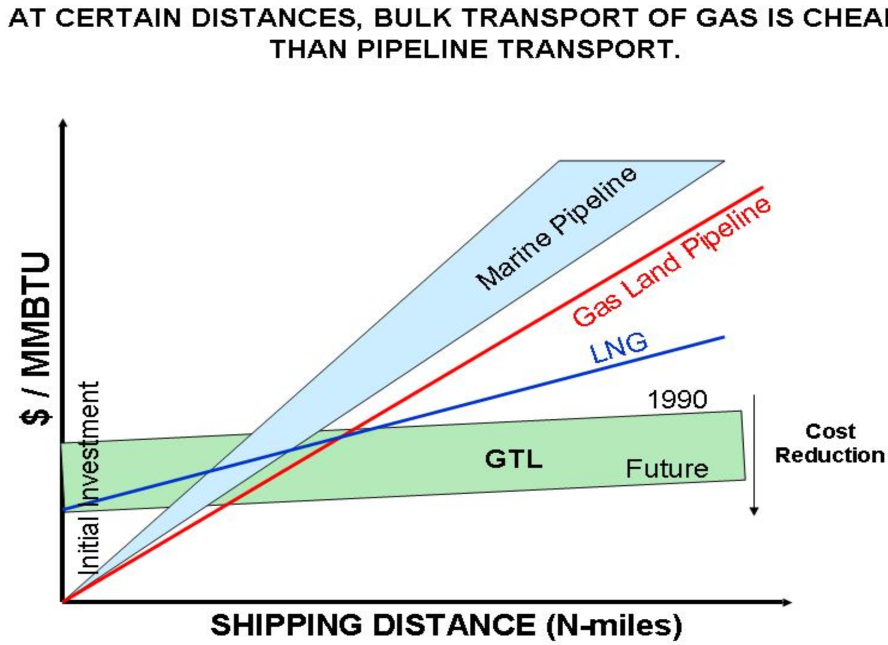
The importance of natural gas as a source of energy has increased substantially in recent years and is only expected to continue. The beginning of the trend seems to have begun after the oil shocks in the 1970s. A frantic search for oil followed, resulting in the discovery of many new gas fields and provided the established (verified) world gas reserves with a dramatic rise in volume and importance. Today, the world's consumption rate of natural gas is about 100 trillion cubic feet (Tcf)/year, only half the rate that the world's established gas reserve is estimated to be increasing at the present [1] [2]. The established world gas reserves are now approaching/exceeding those of the world's oil reserves. Based on the current trend, and after analyzing the relative depletion rates, natural gas appears to have the capacity to outlast oil [3].

Greatest Natural Gas Reserves by Country, 2005

Rank	Country	Proved reserves (trillion cu ft)
1.	Russia	1,680.0
2.	Iran	940.0
3.	Qatar	910.0
4.	Saudi Arabia	235.0
5.	United Arab Emirates	212.1
6.	United States	189.0
7.	Nigeria	176.0
8.	Algeria	160.5
9.	Venezuela	151.0
10.	Iraq	110.0

NOTE: Proved reserves are estimated with reasonable certainty to be recoverable with present technology and prices. [4]

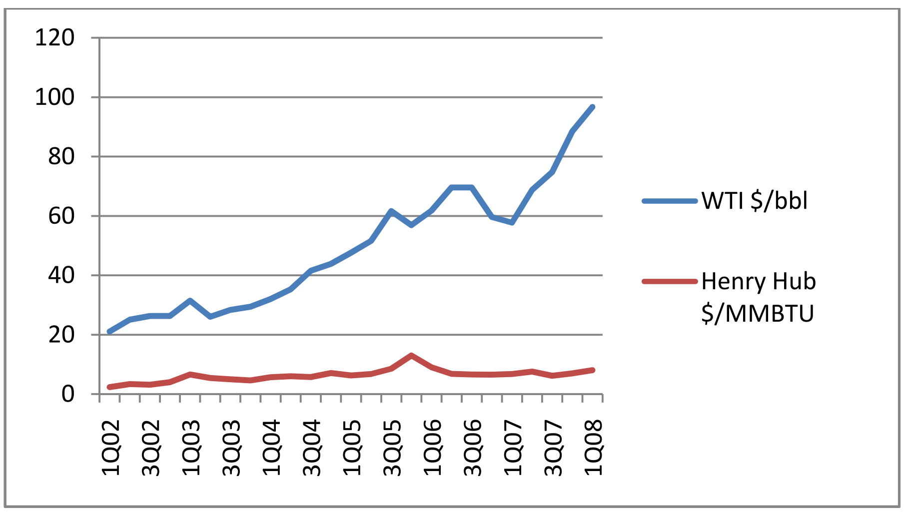
Although the importance of natural gas is increasing steadily, the main drawback remains its low energy density. Consequently, the cost of moving the gas from its original location to the consumer's destination is very expensive, and with reference to remote gases, the cost may prohibit the exploration and development in its entirety. The economics are a simple function of volume and distance. Essentially, transport of any given volume of gas over a relatively short/moderate distance is most economically accomplished via a pipeline. Gas pipeline networks have become extensive, connecting the gas fields of Canada with those in the USA, as well as uniting the Russian Republics with the European consumer grids. Furthermore, plans are currently forming with the intent of connecting Eurasian gas fields with Korean and Japanese consumer areas using a single large offshore pipeline grid. Though the distance is long, the method being considered most seriously involves underwater pipelines, despite the additional costs. Typically, if a consumer requests large quantities of energy in the form of methane and requires long distance traveling, the option preferred is Liquid Natural Gas (referred to as LNG throughout this text). Throughout the past few decades, the creation of multiple advances in technology has furthered our understanding in the assets and uses of the world's natural resources. In addition, with the development of LNG we have launched a mature industry with an impressive performance record and accomplished several successful ventures.



In recognition of the increasing significance of natural gas, many companies have been and continue to commit research toward enhancing the resource profitability, concentrating particularly on reserves in remote regions displaced from the current market. Transportation is continuously being studied in attempts to improve cost for conventional pipelines and LNG schemes. Such improvements are continuing to make the LNG industry an important contributor to the natural gas trade, to the point where it is now internationally traded. Nevertheless, LNG is confined by the limited number of production and receiving terminals for the liquefied natural gas product. Also in certain cases LNG schemes are limited by the accessibility of the site, shipping constraints or weather impediments. Consequentially, another focus has been on processes to chemically convert the natural gas into a liquid, thus creating a Gas-to-Liquids (GTL) industry [5]**.** The petroleum-like liquids of the GTL process have a similar energy density as crude oil, and, hence, require, even if piping the material is required, a much smaller diameter pipeline for the same energy transport. The GTL process not only provides a substantial reduction in the cost of transportation, but also enables access to a far greater geographic market with minimal limitations.

A little over a decade ago, a comparison [6] was made of conventional refining with GTL facilities. It concluded that F-T transportation fuels were not competitive at crude oil prices less than U.S. $20 per barrel. Another conclusion was that the projects are scalable, allowing design optimization and application to various sizes of gas deposits. The key influences on competitiveness include the cost of capital, operating costs of the plant, feedstock costs, scale and ability to achieve high utilization rates in production. As a generalization, however, GTL was felt to be not competitive against conventional oil production unless the gas had a reasonable opportunity value of somewhere around U.S. $0.50 per MMBtu-U.S. $1.00 per MMBtu and was not readily transported. While natural gas offers the advantage of lower feedstock costs than crude oil does, however, it is offset by the higher capital costs associated with manufacturing liquid hydrocarbons via the synthesis route. Those conclusions were made in the 1990s, against a glut of oil and consistent low oil prices.

In recent years the opportunity to convert natural gas profitably has become more evident. The conclusions, made in 1966 against gas of U.S. $0.50 per MMBtu-U.S. $1.00 per MMBtu, are still valid and delineate the low side of the economics, the low oil price scenarios or "cut-off" scenarios against which many projects are still evaluated. In today's environment, we dare speculate that the benchmark of U.S. $20 per barrel has escalated to U.S. $27 per barrel, when inflation were to be taken into account. Should the current (2006–07) cost escalation be reflected, the cut-off oil price is expected to be U.S. $35 per barrel. Importantly, however, in recent years, and particularly since the beginning of 2007, we have seen the parity between crude oil and natural gas completely disappear natural gas prices have not tracked crude oil prices in recent years, as shown in the following graph.



Source: BP Trading Conditions Update-Crude Oil and Natural Gas markers[7]

We can only guess at this point in time as to the reasons for this disparity: is it pure speculation on the "commodity" crude oil market, while the more difficult to transport gas remains less affected and more stable? Domestic natural gas' closest competition is imported Liquefied Natural Gas (LNG). With feedstock competition, comparative returns to LNG development thus influence investment decisions in GTL. To date, LNG returns still appear to be adequate, even though they are not at levels attained 10 or 15 years ago. LNG has thus become a mature industry. Even with the large increases in demand projected, there has been little new project development. The year 2006 has seen no new LNG projects begun in producing nations. Since GTL projects have been started, however, this might seem to indicate that GTL is a viable alternative, or that producers are waiting to see the outcome of the elevated price levels for natural gas as well as oil before making binding decisions.

Certainly on an energy-equivalent basis the disparity between oil and natural gas pricing is flagrant: as an example we take the current market price for diesel in California at U.S. $3.30/gallon. On a pure energy basis, with diesel at 130,000 BTU/gal that would allow an energy equivalent natural gas price of U.S. $25.40/mcf, versus the reality of the market showing a first quarter of 2008 Henry Hub price of U.S. $8.03/mcf (a third of its value). As a result interest in natural gas conversion is at an all time high and GTL projects demonstrate profitability, which they have never enjoyed before.

GTL products find a broad and easy entrance in the market as they, contrary to LNG, require no change in infrastructure from the current petroleum-based one. The GTL products are liquid at atmospheric pressure, fully biodegradable and can be readily used in existing engines and turbines. The quality of GTL diesel is superior to that of crude oil derived diesel fuel, so that it is more likely that GTL diesel fuel will be burned in blends with crude oil diesel. GTL diesel thus allows for upgrading of conventional diesel. It has been proven that a blend with 5%-25% of GTL diesel in conventional diesel already achieves 80 % of the environmental benefits through particulate and emission reductions.

Because of the broad market perspective of the marketable GTL products we will, in this report, consider the option of a full GTL facility, including product work-up train and product distillation. An alternative would be to convert the gas on the North Slope into synthetic crude oil. We have deliberately steered away from this option for the following reasons:

1) A synthetic GTL crude oil has significantly less product value than its readily marketable products.
2) A synthetic GTL crude remains largely a waxy, heavy paraffinic crude, having all the disadvantages of depositing wax molecules along the TAPS line.
3) The synthetic GTL crude has much less ready market access than its marketable products as it would require delivery to refineries rather than directly to fuel distributors.
4) The production of a synthetic crude oil from gas on the North Slope would entail only marginal capital cost and operating cost reductions at the North Slope plant. The GTL plant operator will see between U.S. $25 to U.S. $38 per bbl less for the products.
5) Converting natural gas into transportation fuels will reduce the level of imports but it will not however address the bigger issue of a lack of U.S. refining capacity.

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(3) *Wolf at the Door: "The Beginner's Guide to Peak Oil," also as http://www.wolfatthedoor.org.uk*

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3. TECHNOLOGY

3.1 Summary/Conclusions

The historical development of the Fischer-Tropsch (F-T) synthesis is discussed. Based on chemistry with carbon monoxide and hydrogen derived from town- and coke oven gas the synthesis of liquid hydrocarbons was conceived by Franz Fischer and Hans Tropsch in Germany in 1923. It was, prompted by abundant remote “stranded” reserves and the need for environmentally benign transportation fuels, further developed to world scale gas-to-liquids (GTL) facilities.

The complete process has three distinct steps: syngas generation, Fischer-Tropsch synthesis and product-upgrading. The Fischer-Tropsch synthesis has been executed in two versions: the high temperature version (more suited for production of chemicals) and the low temperature version (suited for production of liquid transportation fuels). For the Alaska North Slope this study focuses on the low temperature version. The various stages of the process, operating parameters and reactor technology are discussed here.

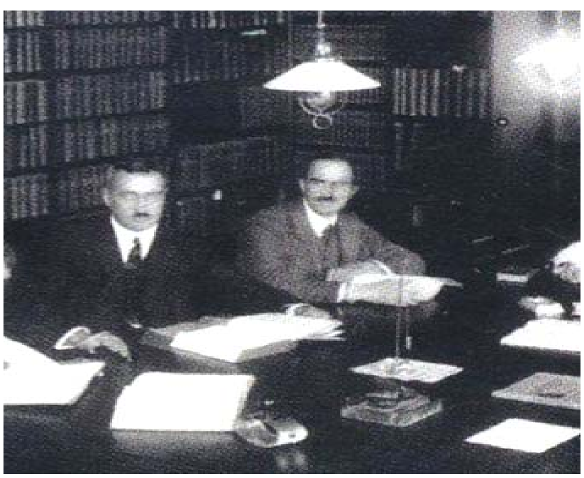
The low temperature GTL technology is currently used by the majors, in joint venture with national oil companies the new dominant players in the oil and gas industry as a tool to monetize natural gas and put it on the books as “replacement oil”. At this point in time there are only two companies worldwide that have operating commercial scale low temperature GTL plants, Sasol with a 34,000 bbl/d plant in Qatar and Shell, with a 15,000 bbl/d plant in Malaysia and a 140,000 bbl/d plant under construction in Qatar. While each company’s technology is financeable in today’s high cost energy market, both have indicated that they only bring their F-T technology to locations where they also participate as an equity owner. Additional players in the market of the near future are ConocoPhillips and ExxonMobil, who respectively committed to build 160,000 bbl/d and 150,000 bbl/d GTL plants in Qatar.

Several of the key players, their R&D, pilot plant as well as industrial activities are individually discussed. It is felt that there is ample room in the hydrocarbon fuels (and specialty) markets for all of these competitors to co-exist.

3.2 Basic Conversion Considerations

Exploitation of remote gas through conversion and transportation is a well-established concept. In various parts of the world, natural gas is converted into chemicals: ammonia, urea or methanol. The market prices of chemical products like ammonia, urea and methanol are highly volatile in the relatively small world market. On the other hand, the prices for transportation fuel are, as we all know, ever increasing, and the market is huge and still growing. Predominantly, transportation fuels are liquids. Gaseous fuels in the automotive business, such as liquefied petroleum gas and compressed natural gas, have had only limited success, even in countries where their use has been stimulated through considerable fiscal incentives. Hence, if the GTL process would yield hydrocarbons, and these hydrocarbons were to be transport fuels, the process would enjoy great potential. Moreover, apart from providing a means to commercialize or book remote gas reserves, this could, in many countries, also serve to reduce the reliance on oil or oil-product imports and, perhaps as important, save on foreign exchange [1]. It is here that the Fischer-Tropsch (F-T) technology fits in. F-T technology converts carbon monoxide and hydrogen, which can be made from any carbonaceous feedstock including natural gas, into liquid hydrocarbons of potentially transportation fuel quality.

The technology of producing synthetic hydrocarbons from synthesis gas with the help of a metal catalyst is not new. It is based on extensive chemistry and engineering work using Carbon Monoxide (CO), and Hydrogen (H_2) to produce a mixture of CO and H_2 (synthesis gas or syngas). The pioneers were Franz Fischer and Hans Tropsch during the early 1920s. They used a precipitated Cobalt-catalyst at normal pressure at the Kaiser Wilhelm Institute für Kohlenforschung in Mühlheim-Ruhr. Various German companies furthered the process using sintered and fused iron catalysts and developing the Fischer-Tropsch (F-T) process. In the absence of substantial indigenous crude oil resources, the German government stimulated research resulting in the manufacture of approximately 600,000 tons per annum of F-T products in Germany during World War II.



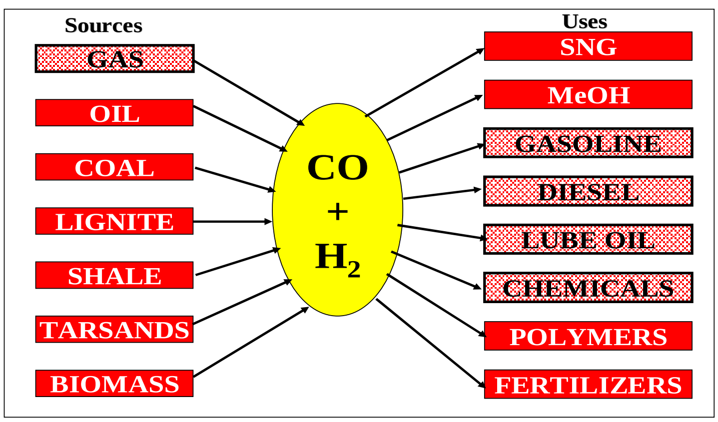
Franz Fischer and Hans Tropsch (1934)

Increased oil product consumption during World War II raised many countries' interest in the F-T process. Developments took place in Japan, the U.K. and the USA. In Brownsville, Texas, a fluidized-bed process plant was constructed and operated between 1948 and 1953. Unfortunately, the attention to synthetic hydrocarbons dropped with the increased discovery of large crude oil reserves in the Middle East. Such is often the case with technology developments as they follow the cyclic pattern and waves of events in the world, as we will discuss here.

South Africa is the exception. Here, the focus on F-T technology use and development has been steady since the 1950s, supporting the country through the oil embargo of the 1970s, 1980s and early 1990s. SASOL, in its isolated position, ought to be commended for the progress in F-T reactor technology it has made from the fixed-beds and circulating-fluidized-beds to the recent slurry-type reactors with precipitated fused iron and cobalt catalysts respectively. These advances are discussed further in this section.

The First Oil Crisis in 1973 and the OPEC oil embargo of 1974 startled the prosperous oil industry and created a frenzy. Many oil companies and government bodies were forced to reassess the world's dependence upon liquid hydrocarbon fuels and the obtainable supply of crude oil. The appeal of synthetic hydrocarbons and the Fischer-Tropsch process was newly revived. Analysis regarding carbonaceous feedstock in the 1970s highlighted the vastly available coal reserves, which put this resource into the spotlight. Attention focused on indirect liquefaction of coal: coal gasification followed by synthesis. This was facilitated by earlier extensive research and development (R&D) work relating to the conversion of various raw materials into liquid transportation fuels. SASOL, as mentioned above, had been active in the field since the 1950s, while oil companies like the Royal Dutch/Shell group of companies had performed such R&D since the late 1940s. Through their R&D, various companies had proven that most carbonaceous feedstock could be gasified to produce this intermediate mixture of carbon monoxide and hydrogen—the building blocks for subsequent synthesis.

CO / H_2 Technology



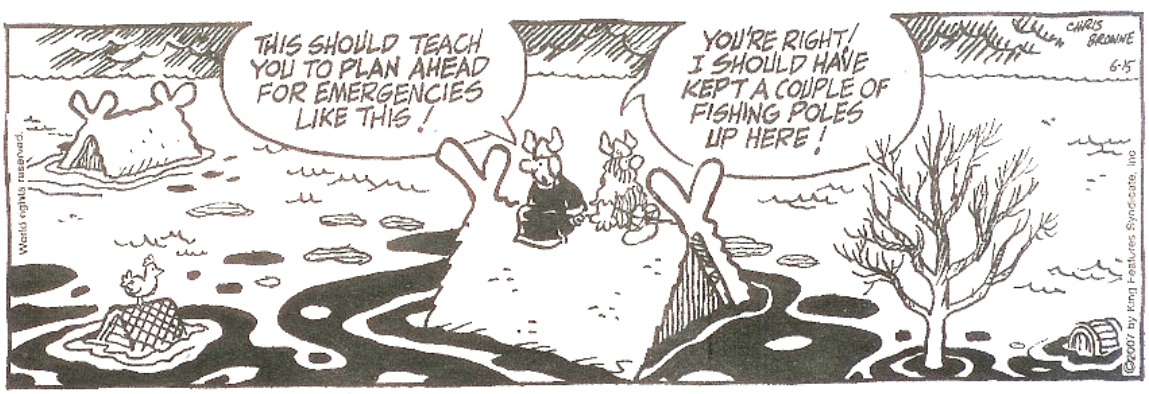
Other factors contributing to the revitalization of F-T interest include the signing of the Clean Air Act by U.S. President Jimmy Carter in 1977 and the increasing pressure to lower lead and benzene levels in engine gasoline. The latter, while furthering the interest in F-T, presented a problem in developing coal as a feedstock. Chemically, coal is best used as a precursor for carbon-rich end products like benzene. Additionally, it was found that handling coal was more elaborate and required a higher level of investment than working with oil or gas. Particularly, this higher investment requirement emerged as the major constraint on the commercial application of coal conversion. The first oil crisis in 1973 and the OPEC oil embargo of 1974 not only spurred interest in synthetic fuels, but exploration and production activities also boomed. These expanded to include offshore operation resulting in the discovery of oil and gas in the North Sea, the Gulf of Mexico and the Alaska North Slope. With the increased drilling for oil, successful discoveries and overall energy awareness, the turmoil of the oil crises calmed. The forecast of oil prices of U.S. $90 per barrel never materialized. Instead, a glut of oil came on the market, prices dropped back to U.S. $15 per barrel and interest in synthetic hydrocarbons ebbed away.

In the wake of the 1970s oil shock, the surge of F-T interest generated the following:

- 1975 and 1979 Sasol commissions two new facilities in Secunda.
- 1984 the Gulf-Badger Process sees the light.
- 1985 Mobil starts its Methanol to Gasoline (MTG) plant in New Zealand.
- 1986 Amoco becomes the first U.S. major to market an all lead-free gasoline product.

Although it was nearly a decade after the oil crisis, the oil companies realized the importance of the quantities of natural gas in the world. The oil industry aggressively drilled for oil in the 1980s; however, instead of oil, gas was often discovered, doubling the world gas reserves over the decade. Unfortunately, there were many cases where the owners could not transport the gas or monetize their assets. In an immediate response to making this remote or "stranded" gas transportable, production of methanol, ammonia, other common products and LNG were studied. Market limitations for these products would only allow for limited exploitation of "remote" gas. As a result, the F-T technology revived again in the mid 1980s. Scientists concentrated on the traditional iron, nickel and cobalt catalysts, but also on more exotic catalytic metals, such as ruthenium. Another focus was testing catalyst promoters and carrier materials for supported catalyst. Nickel is not commercially practical and ruthenium is much higher in cost, so most F-T applications use cobalt- or iron-based catalysts. Cobalt is predominantly used as a component in natural gas conversion. It is used in various combinations with carriers and promoters by most of the players in the field who all have carved out their niche in the market. Therefore, today's field of F-T catalysts is saturated with patents by Shell, ExxonMobil, Statoil, IFP, ENI, Syntroleum, Rentech, Conoco-Phillips, etc. Such limits further research and progress in development. It requires prospective users of F-T technology to enter in the arena of licensing.

The 1980s scene in the field of oil and transportation fuels and the prospects for the near and medium term called for a careful and selective approach to any synfuel development. After all, the direct competition for synthetic hydrocarbons is crude oil and, following the oil crises, the crude oil market prices showed extreme volatility (U.S. $ 15/bbl to over 90/bbl). When crude oil prices rest around U.S.$15/bbl, almost no alternative energy technology can compete with current refining. Our inability to foresee and prepare for the unfortunate scenarios in the past, like the crises of the early seventies, but also current oil prices, presents an important lesson: emergencies come at relatively short notice, and because of the lead times usually involved in technological development, in a crisis the answers to problems always come too late.



Courtesy: Chris Browne/King Features Syndicate Inc.

Similar in use to synthetic hydrocarbon transportation fuels is methanol. In contrast to a transport fuel, methanol either as M85 (a blend of 85% methanol with 15% unleaded premium gasoline) or as "neat" (100 % methanol), has considerable drawbacks, one being modifications required to the fuel distribution systems and another being modifications required to the consumer's car/engine fuel systems. Additionally, methanol has a relatively poor energy density. In layman's terms, methanol is sometimes described as being "half methane and half water." Hence, their transportation cost per energy-unit is high. This is the most important reason why the fuel-methanol market has never developed [2].

On the other hand, synthetic hydrocarbons can be readily incorporated into existing fuels which can be used in existing equipment. Further, middle distillates like diesel manufactured from natural gas have very environmentally friendly properties, upon which we will elaborate in Section 9. The cleanliness of natural gas is transferred into its products making the middle distillates from GTL projects extremely desirable in the marketplace.

In recent years, GTL technology has become a popular subject once again, this time magnified by the increasing evidence of local energy deficits and oil import dependence. The fact that there is stranded and hence "cheap" gas presents challenges to engineers. They face the dilemma of choosing between the optimization of energy efficiency and capital expenditure of GTL plants. This makes the development of various process flow sheets imperative. Engineering improvement and economy of scale are the factors responsible for reduction in relative investment costs for GTL projects. They provided the "technology push."

Gas without a ready market is "stranded" and thus has a much lower intrinsic value compared to the GTL transportation fuels in which it could be converted. There is more awareness of the fact that GTL transportation fuels can reduce Nitrous Oxide (NOx) - and particulate emissions of motor vehicles. Because of the potential to alleviate environmental concerns, GTL fuels have additional value in comparison with conventional transportation fuels. This difference in value provides a "market pull" for synthetic fuel projects with opportunities for both government and private enterprises.

In review, it is fair to state that application of the GTL technology thus combines two aspects of the natural gas business:

1. Bring gas to the market.
2. Bring value to the product.

The renewed interest has become visible over the last few years in the publicly announced F-T studies and projects, which reveal plants ranging from the very large to the very small-scale capacities. Plant sizes as large as 35,000[3], 70,000[4], 80,000[5] and even 150,000[6] barrels per day (bbl/d) have been announced by ConocoPhillips, ExxonMobil, Sasol and Shell. Rentech Inc. and Syntroleum purport the smaller capacities of 500 bbls/d to 20,000 bbls/d. These numbers seem very large; however, in the huge transportation fuels market they easily fit.

It is our belief that the limited number of players in the GTL field, each staking out areas of interest, can truly co-exist. We would even go further in saying that these players need each other to fully exploit the potential of the new synthetic fuels industry.

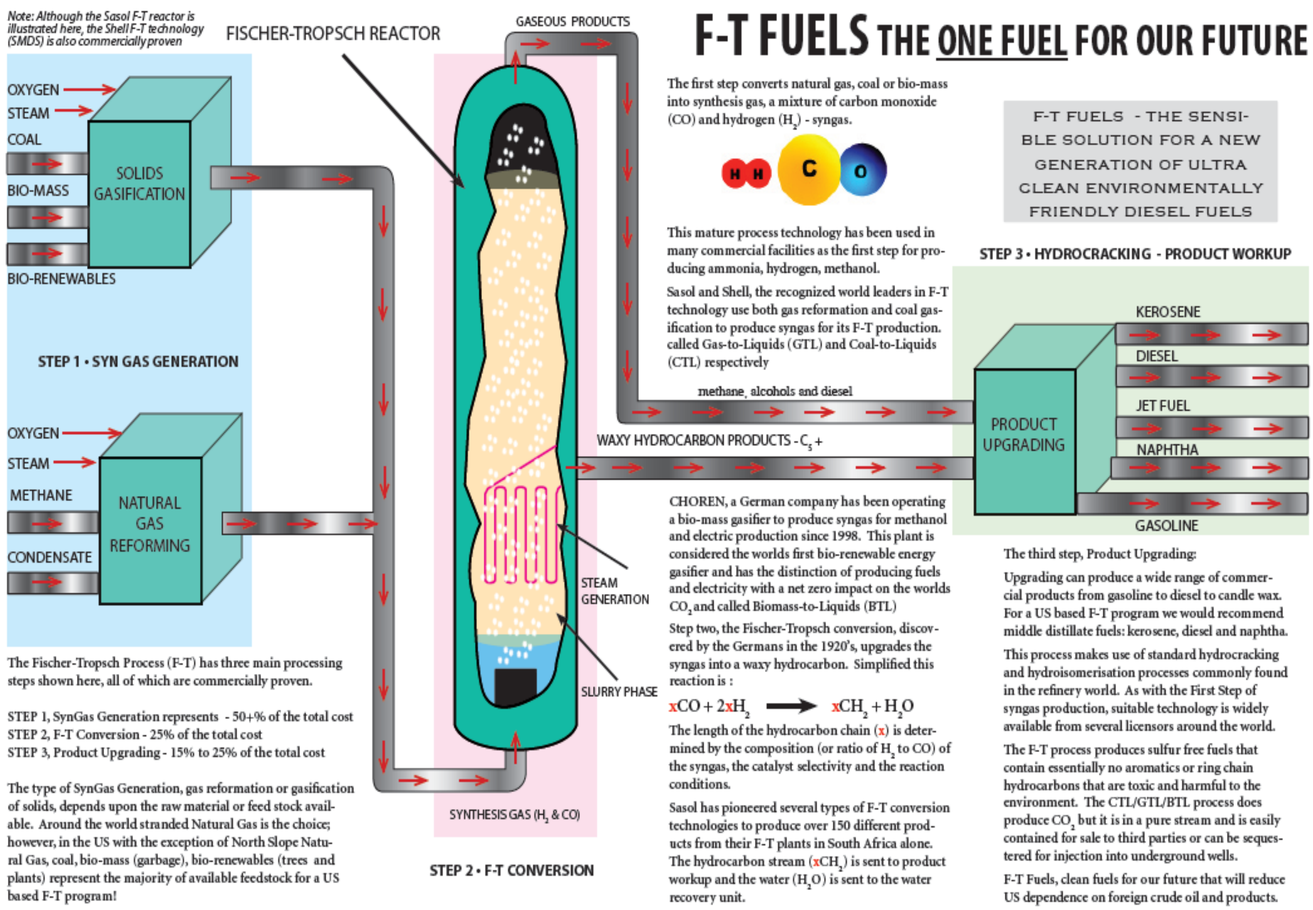
3.3 Fischer-Tropsch/GTL General Process Considerations

In the foregoing, it was mentioned that the Fischer-Tropsch technology converts a mixture of CO and H_2 or synthesis gas (syngas in short) into liquid hydrocarbons. Syngas can have a multitude of origins, being virtually any carbonaceous feedstock. For the F-T synthesis technology, it does not matter where the syngas comes from. In the early days, syngas was derived from town gas or coke-oven gas from the steel industry. During World War II, water gas shift systems were used. Today, using syngas derived from natural gas, the now popular Gas-To-Liquids technology encompasses Fischer-Tropsch synthesis technology as an integral component, so much so the two are almost used as synonymous. The conversion of coal into liquid hydrocarbons (CTL), demonstrated by SASOL in South Africa, includes the F-T synthesis technology as well. Finally, through the role of F-T synthesis, technology in the conversion of Biomass-to-Liquids (BTL), navigating the path of the future in a renewable energy world is possible. One can conclude based on the feedstock that the syngas will be richer in hydrogen from CTL to BTL to GTL. As the F-T process will consume the CO and H_2 in 1:2 ratios, adjustment of the CO to H_2 ratio is often desirable. Syngas contaminant removal and/or other conditioning may also be needed.

The syngas generation may be considered as a separate step in the total process. With this in mind, the conversion route of carbonaceous feedstock to liquid hydrocarbons products then becomes a three-step process:

1. Synthesis Gas Generation
2. Fischer Tropsch Synthesis
3. Product Upgrading

A typical F-T flow scheme, in this case a depiction of the Sasol process line-up is given below:



Before entering in details on the process steps, let's put things into perspective:

- The selection of conversion of natural gas into liquid hydrocarbons was inspired by the growing importance of natural gas and the relatively lower specific capital expenditure, when compared with other hydrocarbon feedstock sources.
- The choice of a paraffinic product package in contrast to an aromatic package was based on the view that clean, middle distillate fuels will continue to have a broad applicability; for example, in automotive diesel engines. Moreover, they represent a substantial growth market, especially in the developing countries. Yet, there are numerous processes to convert the Fischer-Tropsch products into specialties, which would fit smaller markets.
- There remains a constant desire to simplify or improve the technology in an attempt to render it more economical. Various Research and Development efforts have been put forward, some in vain, some with a high potential.

At this point, it is useful to briefly elaborate on the two proposed process routes for conversion of natural gas-to-liquid hydrocarbons: **indirect and direct processes.** The **indirect processes** all consist of a high-temperature stage to convert the raw material to synthesis gas (a mixture of carbon monoxide and hydrogen), followed by a synthesis stage to selectively yield the desired products. **Direct methane conversion** recognizes the economic advantage of reducing the costs of methane conversion to products, particularly the costs of steam reforming. Substantial research has been conducted in the conversion of methane without the use of synthesis gas. This also has the **potential** of higher energy efficiency because the energy intensive syngas production step is eliminated. To date, direct methane conversion processes still require considerable technical advances in order to be commercial. The term "direct" may suggest simplicity, but, generally speaking, this is not the case.

The pyrolysis of methane to higher hydrocarbons is thermodynamically unfavorable. The introduction of oxygen, however, makes the direct conversion thermodynamically possible. Thus, direct methane reforming via the oxidative coupling has been the focus. Two modes of operation have been studied: the redox mode and the co-feed mode. In the former, a metal oxide is reduced in a reactor by methane, which is simultaneously converted into hydrocarbon products. Next, the reduced metal is re-oxidized in a regenerator. Vast quantities of metal-oxide circulation have made this process uneconomical.

In the co-feed mode of operation, methane and oxygen are co-fed over a catalyst. Temperatures of around 1300°F (1000°K) achieve a reasonable degree of selectivity or conversion of methane. Oxygen, rather than air, is used in order to allow for recirculation of unconverted methane without accumulation of the inert nitrogen. In the co-feed operation of oxidative (this correct?), coupling does not meet the standards of conversion and selectivity. Unfortunately, the rule of "conversion plus selectivity equals 100%" has been observed, with either conversion or selectivity on the low side. As low selectivity does not yield the products desired and low conversion per pass implies in practice vast recirculation flows of unconverted methane, this technology still requires considerable technical advances in order to become commercial [8].

With this introduction, an overview of "state-of-the-art" GTL technology is in order. As parts of this section we will respectively discuss the three components of the GTL process, i.e. the Gasification Processes, Fischer-Tropsch Chemistry and Product Work-up. Additionally, we should not forget the players in the field, some of which have already been mentioned in the foregoing text. Hence, we will dedicate a part of this section to the "competition in the field."

Conversion Efficiency – Capital Costs

Starting with a natural gas feedstock, we may remark that natural gas sold as LNG will earn the natural gas consumption price, and natural gas used for GTL will earn the diesel, or more generally, middle distillate product prices. A chemical engineer can make a carbon mass balance and calculate how many methane molecules from a natural gas stream it takes to produce a barrel of F-T product. For all practical purposes, we will assume here that methane is the main constituent in natural gas (95% is generally a good assumption). Natural gas is not sold per molecule, but per volume or per unit of heat that the molecules generate upon combustion: it is often sold in dollars per million of British Thermal Units (MMBtu). Since we know the heat of combustion of a molecule of methane, we can thus calculate the relation between MMBtu of natural gas and barrels of F-T product: ***A good "rule of thumb" is roughly 10 MMBtu per barrel of F-T product***. That said, second and third generation GTL/CTL such as Sasol and Shell are closer to 8 MMBtu per barrel of F-T product.

In other words, it takes quite a number of Btus or quite a volume of gas to produce a barrel of F-T product. Therefore, there is an important cost multiplier connected to the gas price, which is embedded in the cost of the end product. This leads to the notion that the GTL process needs reasonably priced (some say low-cost) natural gas in order for the F-T product to compete with crude oil derived products. A simple example can make this comparison with diesel transportation fuel clear: If natural gas for the F-T process is priced at U.S. $1.00 per million Btus (10 cents/therm) the diesel produced needs to be able to be sold at a value of U.S. $10.00 per barrel, or some 25 cents per gallon, in order to recover only the feed gas cost. Of course, in addition to feed gas costs, there is labor, maintenance, catalyst and chemicals costs that need to be recovered as part of the out-of-pocket expenses, which combined with capital expenses and profit should give a marketable product. Each F-T technology has a different conversion ratio associated with it as each has a corresponding capital cost. **Selecting the right F-T technology for a specific project/location depends upon a detailed engineering review of a multitude of factors.**

3.4 Syn-Gas Generation (Gasification or Reformation)

The three main processes to convert gaseous and/or (light) liquid feedstocks is conversion by partial oxidation, steam methane reforming or the combination of those two. Higman and van der Burgt have adequately described the technology to convert carbonaceous feed stocks into synthesis gas, as well as the auxiliary technologies such as gas cleanup in their book: Gasification [7].

Gasification or partial oxidation, at least of coal, is an old technology, having formed the heart of the town gas industry until the widespread introduction of natural gas. With the decline of the town gas industry, gasification became a specialized, niche technology with limited application. After substantial development, gasification is now enjoying a considerable renaissance, documented by the large number of project in various stages of planning or completion at this time. The reasons for this include the development of new applications in gas-to-liquids projects, the prospect of increased efficiency and environmental performance, including CO_2 capture, applications in integrated gasification combined cycle (IGCC) projects, as well as the search for an environmentally benign technology to process low-value or waste feed stocks. In 2002 some 5.4 trillion cubic ft/d of synthesis gas was produced by partial oxidation of liquid or gaseous feeds [9]. By far the largest portion of this synthesis gas (about 80%) is generated from refinery residues, producing predominantly ammonia, methanol, refinery hydrogen or power. Most plants with gaseous feeds are small units for the production of CO-rich synthesis gases, particularly for the production of oxo-alcohols.

There are three principle processes for the manufacture of synthesis gas from natural gas, partial oxidation, steam reforming and catalytic auto thermal reforming. The hydrogen to carbon monoxide ratio of the syngas is an important characteristic distinguishing between these three processes. Unless there is the possibility of importing CO_2 the typical range for the three processes with and without CO_2 recycle is:

Process	H_2/CO ratio	
	with CO_2 recycle	without CO_2 recycle
Steam reforming	2.9	6.5
Catalytic auto thermal reforming	1.7	3.7
Partial oxidation	1.55	1.81

Thus the desired ratio of hydrogen and carbon monoxide in the resulting syngas product stream is an important factor in the process selection. Note, however, that with partial oxidation the CO_2 produced is small and so also the effect of CO_2 recycles. For this reason CO_2 recycle is seldom applied with partial oxidation units.

The other determining factor is primarily an economic issue, namely the availability of oxygen, which is needed for both the auto thermal reforming and partial oxidation. For small plants it is seldom economic to build a dedicated air separation plant. Hence, if no pipeline oxygen is available or synergies with a gas supplier cannot be realized, steam reforming would be selected for such plants, despite the fact that the potential surplus hydrogen normally can only be used as fuel. For larger facilities it is almost always more economical to select the partial oxidation or auto thermal reforming route. The largest single gas-fed partial oxidation plant is the Shell unit at Bintulu, Malaysia, which serves as the front end for the Shell version of the GTL process, also known as Shell Middle Distillate Synthesis (SMDS) process. When a catalyst is used in combination with the partial oxidation process, the operating conditions can be much milder. The largest of such catalytic partial oxidation plant is the PetroSA GTL facility at the Mosselbay in George, South Africa.

Partial oxidation or natural gas gasification is, compared with other feed stock, relatively simple. It involves mixing of the natural gas with oxygen. The pre-mixed natural gas/oxygen mixture is then under pressure (typically 400-600 psia) sub-stoichiometrically combusted in a refractory lined pressure vessel, creating a hydrogen-rich syngas. The chemical reaction is the following:

$$CH_4 + O_2 \rightarrow CO + 2\ H_2$$

A distinction is made between *thermal partial oxidation* (TPOX) and *catalytic partial oxidation* (CPOX). TPOX reactions, which are dependent on the air-fuel ratio, proceed at temperatures of 2200°F and above. In CPOX the use of a catalyst reduces the required temperature to around 1500°F - 1650°F. The choice of reforming technique depends often on the sulfur content of the fuel being used. CPOX can be employed if the sulfur content is below 50 ppm. A higher sulfur content would poison the catalyst, so the TPOX procedure is used for such fuels.

Steam reforming of natural gas, sometimes referred to as steam methane reforming (SMR) is the most common method of producing commercial bulk hydrogen as well as the hydrogen used in the industrial synthesis of ammonia. At temperatures of 1300°F – 2000°F and in the presence of a metal-based catalyst (nickel), steam reacts with methane to yield carbon monoxide and hydrogen. The chemical reactions that take place are:

$$CH_4 + H_2O \rightarrow CO + 3\ H_2$$

$$CO + H_2O \rightarrow CO_2 + H_2$$

The produced carbon monoxide can combine with more steam to produce further hydrogen via the water gas shift reaction. The first reaction is endothermic (consumes heat), the second reaction is exothermic (produces heat).

3.5 Fischer-Tropsch Processes

3.5.1 Chemistry, Catalysis and Operating Conditions

The Fischer-Tropsch process is a catalyzed chemical reaction in which carbon monoxide and hydrogen are converted into liquid hydrocarbons of various forms. The principal purpose of this process is to produce a synthetic petroleum substitute for use as synthetic lubrication oil, as synthetic fuel or as specialty chemical compounds.

Typical catalysts used are based on iron and cobalt. The chemical reactions that take place are:

Paraffin formation	$nCO + (2n+1)\ H_2 <=> C_nH_{(2n+1)} + nH_2O$
Olefin formation	$nCO + 2nH_2 <=> C_nH_{2n} + nH_2O$
Alcohol formation	$nCO + 2nH_2 <=> C_nH_{(2n+1)}OH + (n-1)H_2O$
Water gas Shift	$CO + H_2O <=> CO_2 + H_2$,
Boudouard reaction	$2CO <=> C + CO_2$
Carbon deposition	$CO + H_2 <=> C + H_2O$

The mechanism of the Fischer-Tropsch reaction is one of "chain growth." We will not give an academic dissertation of such "chain-growth" here, but reference is given to various papers written on this growth mechanism. One may look up the groundbreaking work of Schulz-Flory and Anderson as well as the articles of Prof. Dr. E. Iglesia (ex Exxon, now professor in Berkley), Dr. E. W. Kuipers (Shell) or more recently the dissertation of Dr. G. P. van der Laan to go into the details.[10][11][12][13] However, in general one distinguishes two routes for the chain growth:

1. The traditional CO and H_2 combination via the Anderson-Schulz-Flory (ASF) probability of growth, or
2. The "Olefin reinsertion" mechanism.

The following describes both mechanisms in broad terms:

a) The traditional ASF chain growth

The traditional ASF chain growth is the originally discovered, most commonly accepted mechanism. One can envisage that the hydrogen and carbon monoxide, which are chemisorbed on the catalyst surface in the F-T process, can produce many different intermediate species. The main initial reaction, which takes place on the catalyst surface, can be described as:

$$CO + 2\,H_2 \rightarrow -CH_2- + H_2O$$

Described in words, this means that carbon monoxide and hydrogen initially form a methylene specie on the catalyst surface. Anderson et al. analyzed the product distribution for various fixed bed catalyst.[4] They found that graphs of log W_n/n plotted against the carbon number "n" gave a straight line for many products (W_n is the carbon weight fraction of product with carbon number n). This then means that the methylene specie has a "grow-chance" to continue its growth to a longer chain product, which is more or less constant. In the ASF theory, this "grow-chance" is also called "alpha or α."

Expressed in an equation, Anderson, Schulz and Flory found that

$$W_n = n*(1-\alpha)*\alpha^{(n-1)}$$

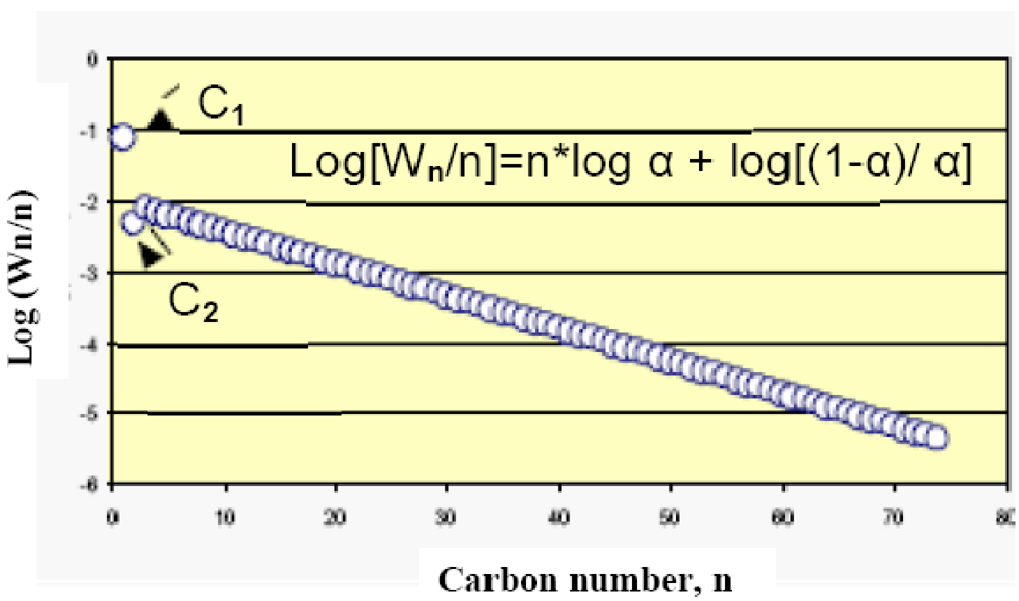
Or $\log [W_n/n] = n*\log \alpha + \log[(1-\alpha)/\alpha]$, also called the ASF equation.

Hence, one distinguishes under the ASF theory only two distinct single product selectivity's: if "alpha" is zero, 100% methane is formed; if "alpha" is one, the end product is entirely wax. Therefore, an "alpha" value in between zero and one produces a blend of hydrocarbons of varying chain length. Since the blend of hydrocarbons from the F-T synthesis looks very much like a paraffinic crude oil, it is sometimes referred to as synthetic crude or syn-crude. In practice, deviations of the straight line plot of log $[W_n/n]$ versus the carbon number n have been found. Notionally it was found that:

* methane yields are often higher than predicted

* C_2 (ethane and ethylene) yields are often lower than predicted.

The following graph shows the plot we referred to in the aforementioned:



b) The "Olefin reinsertion" mechanism

The olefin reinsertion mechanism is a development of later date. It is one of the refinements of the original theory and explains a secondary growth mechanism, along the following lines of thought: Sometimes, full hydrogenation of the inserting CO molecule does not take place and an olefin will be created on the catalyst surface. Such creation is frequently followed by chain termination (for iron catalysts more than for cobalt catalysts); hence, the F-T product can be rich in "alpha olefins." The intrinsic reactivity of the double olefin bond allows for re-insertion of the olefin specie in a growing chain. This is called the second chain growth mechanism.

In practice, one can influence the "alpha" through the selection of the type of catalytic metals, the operating temperature and pressure. By choosing the right catalyst composition and operating conditions one can thus steer the "alpha" to a certain value. For example, it has been found that catalyst and conditions can be found, which predominantly produce lighter material like gasoline and diesel quality hydrocarbons. Let's discuss the individual parameters:

Catalyst composition

To date, cobalt and iron-based catalysts are the commercial catalysts, although a ruthenium based catalyst is also contemplated in work by the Japanese National Oil Company (JNOC). Their common denominator is that they were all developed with the desire to obtain a more complete conversion of the syngas to liquids than the Germans achieved. Such higher conversion is obtained through the "fine-tuning" of metals of Group VIII in the periodic system with promoters for cobalt and ruthenium or with (alkali) additives in the case of iron. Ruthenium has, at low temperature, the capability to produce heavier hydrocarbons and is more active than cobalt or iron, but also substantially more expensive and rare. At high temperature, however, ruthenium is an active methanation catalyst.

In recent years, some companies claim to have invented "chain-limiting" catalysts; however, detailed information on such catalysts is not available. In general, it is believed that the presence of certain wax molecules from the F-T reaction can never be avoided. The "chain-limiting" effect of certain catalysts is thus thought to be more the result of experimental inaccuracies (the wax molecules are "lost") or to be the effect of a bi-functional catalyst. In the latter case, the F-T wax molecules are cracked with the help of a different catalytic metal present on the same carrier as the active metal for the F-T reaction or on a second catalyst. In the latter case, zeolites have been proposed. [14] Indeed, if one could constrain the by nature imposed F-T polymerization kinetics by physical impositions on the molecules deviation of this kinetics mechanism would occur. Examples are systems developed by Mobil that substantially couple the properties of the F-T catalysts with the shape selectivity of zeolites. [15]

Operating pressure

Increased pressure during the F-T reaction leads to two effects:

1) a limited increase in chain growth, hence a shift to heavier products and increased hydrocarbon liquids yield, and
2) more importantly, increased saturation of the chains (less olefins).

The best illustration of the effect of pressure comes from the old German work. After their initial work at atmospheric pressure the Germans developed the medium (ca. 10 bars, 140 psi) pressure Fischer-Tropsch process during WW II. The medium pressure process used a simpler reactor than the low-pressure system. More importantly, it allowed for higher productivity per reactor while making a quality-wise improved product slate. The following table shows the difference in individual product yields obtained by the Germans:

Product	Low Pressure - 1 bar - product yields (%wt) (in parenthesis % olefins)	Medium Pressure - 10 bar – product yields (%wt) (in parenthesis % olefins)
LPG (C_3-C_4) – Gasol	10	10 (40)
Gasoline – Benzin	53 (28)	25 (24)
Diesel – Kogasin	26 (15)	30 (9)
Soft Paraffin Wax - Gatsch	7	20
Hard Paraffin Wax - Gatsch	4	15

Operating temperature

The temperature of reaction is a parameter, which highly influences the termination of the chain growth. In practice, we distinguish between the Low Temperature Fischer-Tropsch (LTFT) process, producing a mixture with a large fraction of heavy, waxy molecules or the High Temperature Fischer-Tropsch (HTFT) process, which is selected to produce a light product stream and olefins. The LTFT is therefore adequate for the production of synthetic transportation diesel fuels, while the HTFT is more apt to produce chemical feedstock.

In the case of LTFT process, the operating temperature is 390ºF–480ºF (200ºC –250ºC) and the "alpha" is generally 0.9 or higher.

In the case of HTFT process, the operating temperature is 570ºF –660ºF (300°F –350ºC) and, since the reaction to large waxy molecules needs to be minimized, the "alpha" is in the order of 0.65. Few large, waxy molecules, which might be formed, are in the case of HTFT cracked in-situ. They are the cause of carbon deposition on the catalyst and reduce the catalyst life.

3.5.2 F-T Reactor Technology

When discussing the Fischer-Tropsch reactor technology, the main consideration in the selection of the reactor is to obtain the best possible conversion of syngas to the desired products while being able to suitably manage the enormously exothermic reaction:

$$CO + 2\,H_2 \rightarrow -CH_2- + H_2O \qquad \Delta H = -165 \text{ kJ/mol}$$

The heat of reaction is here expressed through the enthalpy Δ H. It can, in relative terms, also be described via the thermal efficiency. The thermal efficiency is defined as the ratio of the energy in the products of the reaction over the energy of the reactants. That means that there is a relation between the product make (i.e. carbon efficiency) and the energy efficiency. For the Fischer-Tropsch process of today, the current maximum of thermal efficiency is some 65%. Therefore, this implies that about 35% of the energy into the process is not converted to (chemical) energy of the products, but is released as heat (thermal energy) instead. Thus, almost one-third of the energy into the F-T process needs to be handled as heat. However, do not even think that the energy is lost! Engineers have found ways and means to recover this energy to the largest extent. Additionally scientists are constantly working on catalyst and process improvements, with the objective to increase conversion and product yields at the expense of losses and off-gases (see Section 10).

At this point it is in order to discuss the efficiency of a potential North Slope project in more detail. From a carbon balance point of view it takes a certain minimum volume of natural gas (predominantly methane) to produce a barrel of F-T liquids. Obviously if the gas is containing loads of nitrogen, or other inert gases, corrections need to be applied. As explained above under the "grow-chance mechanism" the F-T catalyst produces a full range of hydrocarbon product, from methane (C_1) to long chain paraffins (up to C_{100}). It therefore depends on the definition of "liquids" where the cut-off point is. It has been known that technology vendors (Syntroleum) define their liquids as propane and higher hydrocarbons (C_3^+ - liquids). The general definition, however, is pentane and higher (C_5^+ - liquids). It shall be clear that every technology vendor has interest to achieve as high as possible liquids yield, as "making gas out of gas" can never be a virtue. Also the catalyst age and operating conditions obviously play a role. In this study we have not selected any specific technology and, hence, need to generalize. It is valid to state that with modern catalyst at end or run conditions (i.e. before the catalyst needs to regenerated or replaced) a F-T process should be able to make one barrel of $C_5^{+\,-}$ liquid hydrocarbon from little less than 10,000 scf of predominantly methane natural gas or 10 million Btu. The multiplier of 10 million Btu per barrel of F-T liquids makes an easy to remember and handy calculation tool. In effect modern F-T technology is shifting to higher efficiency, so that a number of 8 million Btu/bbl is closer to today's reality.

Keeping in mind that we have the low temperature Fischer-Tropsch (LTFT) technology and the high temperature Fischer-Tropsch (HTFT) technology, the reactor, therefore, should not only cope with the important aspect of removing the heat of the F-T reaction, but also with the feed gas composition and the F-T products, which can be either in the gas phase (HTFT) or in the liquid and gas phase (LTFT).

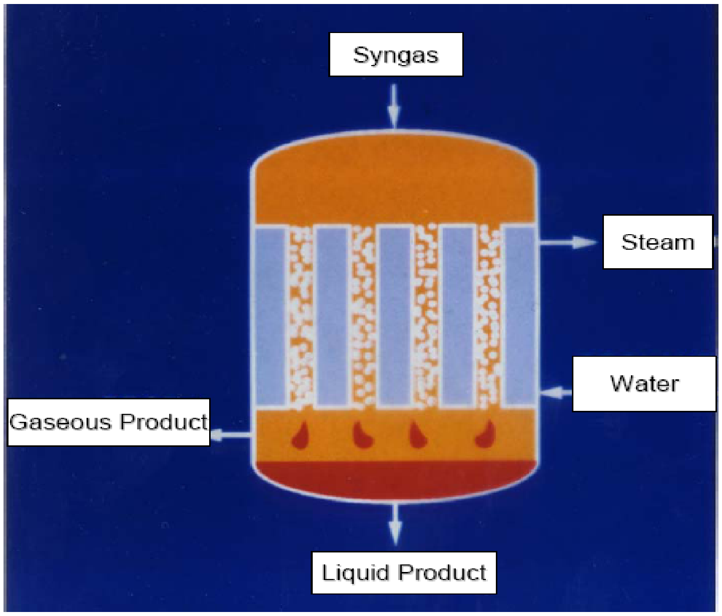
The HTFT was and still is used since the 1950s in South Africa. In the rest of the world, it has lost in the recent two decades its popularity in favor of LTFT. This is partially caused by the complex product slate produced in the HTFT process. For example, the gasoline fraction produced contains large quantities of benzene and its derivatives, undesirable in the eyes of many transportation fuel consumers. HTFT, therefore, offers more opportunities for chemical applications instead of the vast fuels market. Another aspect of the HTFT technology is the production of large quantities of gaseous, light hydrocarbons, or "synthetic natural gas (SNG)." Elsewhere in the world, the conversion of natural gas to SNG is not a virtue. In South Africa, with a market for SNG, HTFT has proven to be an elegant way to convert coal into SNG, chemicals and transportation fuels.

From the aforementioned is shall be clear that the HTFT produces a much lighter hydrocarbon product as well as more gas than the LTFT version. The interest in the LTFT is mainly caused by the increased finds of natural gas reservoirs, of which a substantial quantity is "remote." Conversion of this stranded gas into transportable diesel would allow it to find a vast market. Since there is no virtue for a potential Alaska North Slope GTL plant to "produce gas out of gas" we will in the following limit ourselves to concentrate mainly on the low temperature version.

Multi-Tubular Reactor

The multi-tubular reactor (MTR) is also called the multi-tubular fixed bed reactor. It is basically a vertical shell and tube heat exchangers where the catalyst is packed in the tubes, which are surrounded on the shell side by a cooling fluid (boiling water/steam or oil). The cooling fluid serves to remove the heat of the F-T reaction. The advantage of the MTR is that the concept has a linear scale up. Each tube acts as an individual reactor. Consequently, once it is understood what **one single** reactor tube's behavior is under the F-T conditions, it is a matter of how many tubes can be fitted in one vessel and it is understood what **a multi-tubular** reactor will do. There are two industrial applications of the multi-tubular reactor, the Arge reactor with Sasol in South Africa and the Shell Malaysia multi-tubular reactors. Additionally, BP has a demonstration plant in Nikiski, Alaska, which also uses a MTR.

The following picture gives a schematic of the "multi"-tubular reactor, where "multi" (Latin for many) is used for the "four" tubes shown.



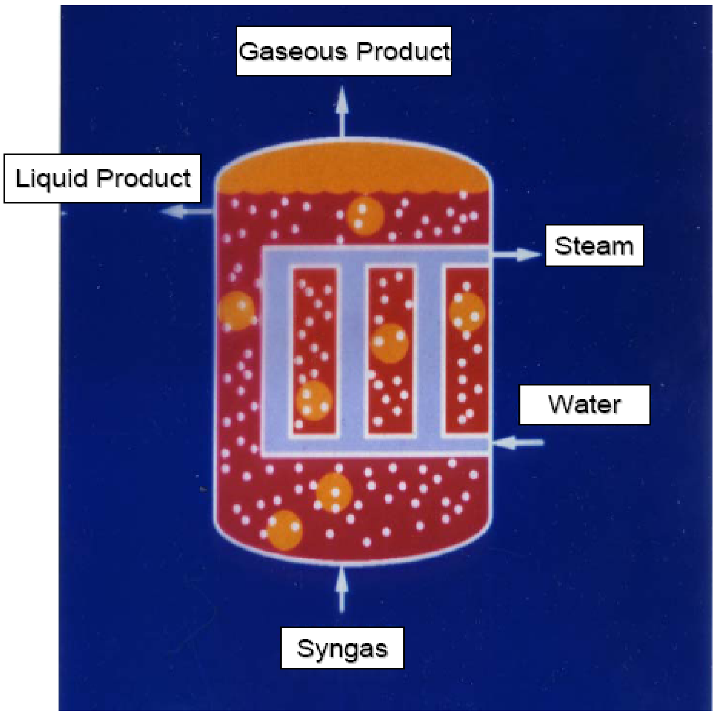
The heat removal of the MTR in Fischer-Tropsch technology applications has been demonstrated with cooling oil and steam generation. The oil cooling applications have been limited to pilot plants. In the case of pilot plants, the operation is frequently intermittent. The heat is then not a reliable source for any heating application. Moreover, for the pilot plant applications hot oil circuits are cheaper to install and easier to operate. In other applications of the MTR, the use of molten salt as a cooling medium has also been demonstrated. Obviously, the effective operating temperature of the salt (mixture) determines the window of operations of such applications.

Slurry Bubble Column Reactor

The Slurry Bubble Columns Reactor (SBCR) can be equally well characterized as a vertical heat exchanger, where the respective cooling and process functions are inverted to the ones of the MTR, i.e. the flow of cooling medium in the tubes and the process side in the shell. Other variants to remove heat, however, are equally possible.

The SBCR, as shown below, consists of a vessel containing slurry of process derived wax with catalyst dispersed in it. Syngas is bubbled though this slurry and reacts with the catalyst to form more hydrocarbons.

The heat is removed from the slurry by means of cooling tubes, inside of which steam is generated. Light hydrocarbon products and unconverted syngas are recovered from the freeboard in the top of the reactor. The heavier hydrocarbons mix with the slurry and are removed from the reactor as a side draw. This side draw can be the complete mixture of slurry and catalyst, in which case external catalyst wax separation facilities are needed. Alternatively, devices internally in the SBCR allow in-situ separation, so that the catalyst stays (mainly) in the reactor and (relatively) clean heavy hydrocarbon product is extracted.



The advantage of the SBCR lays in the elegant removal of the heat of the F-T reaction. The syngas can simply be bubbled through the liquid products of the F-T reaction, while the catalyst can be dispersed in the same, making it a mixture of gas/liquids/solids. As a result, catalyst loading is less critical and pressure drop is low.

In principle, the catalyst is ideally mixed with the liquid product and the syngas, resulting in three features:

1. Ideal heat transfer from the catalyst via the liquid product to the cooling tubes in a turbulent environment of a bubbling mixture.
2. Uniform catalyst utilization as each catalyst particle in the bubbling bed has equal opportunity to react.
3. On-line catalyst withdrawal and addition.

In contradiction, it has to be mentioned that obviously the heat transfer is only ideal in dilute systems. In scaling up and maximization of the SBCR, performance slurry catalyst loading becomes an important tool. Not only does this have consequences for the slurry viscosity and ability to mix, it also influences the ratio of heat generation to conduction. Your author has witnessed operations where the catalyst in the bottom of the SBCR simply became overheated on initial contact with the syngas and disintegrated.

Because the SBCR is well mixed, the catalyst sees the outlet gas concentrations of reactor. This limits the conversion of the SBCR in once-through operation. Staging inside the SBCR and/or operation of SBCRs in series circumvents this disadvantage.

Equally well, the ideal mixing of the catalyst in the SBCR implies the exposure of the total batch of catalyst to any catalyst poison entering the system. On-line catalyst withdrawal and addition facilitate the catalyst change out. Since the catalyst is moving with the product fluids (moving bed technology) catalyst recovery and separation from the products is required. Catalyst attrition, and measures to prevent this, plays an even more important role.

Finally, but most important of all, the dispersion of the syngas in the SBRC needs to be understood. It is particularly the latter that has hampered the SBCR development during the years after its inception.

Fluidized Bed Reactors

The fluidized bed technology also facilitates convenient control and handling of highly exothermal reactions. It can be characterized by high temperature operation and short contact times between the catalyst and the reaction components. As a result, in the application of fluidized bed reactors only the high temperature F-T technology is applicable. Here, deliberate curtailing of the length of the hydrocarbon molecule is of essence in order to keep the catalyst from sticking together and remain in the fluidized form. An iron catalyst, operated at 25 bars (400 psi) and 350 ºC is used to achieve that. With the synthesis feed gas keeping the catalyst in fluidized form, the gas-solids are well mixed, so the reactor operates at approximately constant temperature throughout.

The original technology dates back to the 1940s when Standard Oil (of New Jersey), later Exxon, developed the circulating fluidized bed technology for their fluidized catalytic cracking or FCC technology used in gasoline production.

The first fluidized bed reactor used in F-T was the Hydrocol reactor of the Brownsville plant in the USA. The plant used a fixed-fluidized bed F-T reactor system, a variant of Exxon's FCC technology, developed by Hydrocarbon Research Inc (HRI) of Trenton, New Jersey. It was erected at the Carthage Hydrocol Inc. site in Brownsville, TX. The plant was to make gasoline. Regarding the Brownsville plant history, it is said that it went through a difficult, lengthy start-up phase. By the time operating difficulties were overcome through redesign of the plant, natural gas prices doubled, the process became uneconomical and the plant was shut down in 1953 [16] [17].

M.W. Kellogg, who was the principal engineering contractor in the development of the fluidized bed process, would later profit from the experience in this field in its involvement in the first Sasol fluidized bed reactor. Based on their experience with the circulating fluidized bed (CFB) technology, M.W. Kellogg introduced this technology, for F-T called the Synthol reactor technology, at Sasol's Secunda plant in South Africa. The introduction was not without problems, leading Kellogg to abandon the development to Sasol [18]. Ultimately, Sasol operated 16 Synthol reactors in Secunda and 3 additional ones in Sasolburg[19]. Similar to the catalytic cracking technology, only a small volume of the catalyst is in the reacting part of the circulation loop while the bulk is in the section for product/catalyst separation. High catalyst attrition and erosion of the circulation loop were also drawbacks of this system. The Synthol fluidized beds were operational between 1955 and 1998.

Because of its potential economic advantages, Sasol has been doing extensive pilot plant work on the fixed fluid bed technology since the mid 1970s. This resulted in two years of successful operation in a field test unit [20]. In 1989, Sasol commissioned, in Sasolburg, the first commercial Sasol Advanced Synthol (SAS) reactor, an ebulating bed or fixed fluidized bed (FFB) system with internal heat exchange.

The FFB system has many advantages over the CFB system, such as:

- in the FFB, the catalyst remains in suspension and does not circulate as is the case in CFB;
- the FFB reactor is, for the same capacity, considerably smaller, hence less steel is used in vessel and structure;
- lower power consumption for gas and catalyst circulation;
- fewer reactors for the same capacity;
- the lower velocity in the FFB reactor reduces erosion, but also moderates catalyst attrition and;
- lower maintenance cost.

In 1995, the first SAS reactor with a diameter of 8 meters and capacity of 11,000 bbl/d of F-T product was commissioned. In 1999, the SAS reactor concept was taken to 10.7 meter diameter (28 meters high) and 20,000 bbl/d capacity, and since, the 16 Synthol reactors have been replaced with 8 SAS reactors. Based on the success of the eight SAS reactors, previously installed, a ninth reactor was commissioned in 2002 [21].

(Photo-courtesy Sasol) Sasol SAS and Synthol reactors

The only other, though unsuccessful, F-T fluidized bed application known has been in the development of the Gulf-Badger process. The Gulf-Badger process, invented in 1984, combined the catalysis research work on Fischer-Tropsch and the reaction engineering of Gulf Oil with the process and engineering design provided by Badger [22] [23]. Badger was initially involved because they had experience with fluid bed reactors and already had two of them set up in their lab. Gulf management wanted rapid development and did not want the time delay to build its own reactors. Gulf researchers apparently advised against using the cobalt catalyst in a fluidized bed reactor but the work progressed to the point where catalyst was prepared. Allegedly, the catalyst proved to be so active that they had to strip insulation off the reactors when the reaction started to go out of control. Reportedly, more money was spent on the fluid bed work in six months than Gulf had spent in the previous six years. The result was that the catalyst behaved just as Gulf researchers had predicted. The unit ran fine for half a day or so but then it began to be difficult to keep the catalyst suspended. The catalyst had to be hydrogen-stripped once or twice a day, and the methane make was so high during those stripping periods that the overall selectivity to liquids was rather poor. From thereon the Gulf-Badger process developed as a LTFT fixed bed process.

3.6 F-T Product Upgrading Technology

The predominantly linear paraffinic, raw Fischer-Tropsch product is composed of carbon, hydrogen and (few) oxygen molecules only. The product is sulfur-free as the F-T catalyst has an intrinsic affinity for sulfur. The liquid product is also saturated with the other main products of the reaction, water, and the by-products of the synthesis, lower alcohols and acids, of which acetic acid is normally the main one. The raw product contains olefins, mainly alpha olefins. The olefin content is a function of the catalyst and process conditions. In general, the iron catalyst produces more olefins than the cobalt catalyst.

The F-T catalysis and chemistry has been discussed above in Section 3.4.1. Therefore, it suffices to mention here that the length of the paraffinic hydrocarbons is determined by the catalyst and process conditions: Product yields assume to be a stepwise polymerization type chain growth procedure, since 1951 named the Anderson-Schulz-Flory (ASF) distribution. The chain growth probability factor, alpha, is assumed to be independent of carbon number [24] and the mass fraction of each component a function of alpha. $m_n = (1-\alpha)\alpha^{n-1}$

In the high temperature process variant, the alpha is limited to allow production of hydrocarbons in the gas or vapor phase only at reactor operating temperature of 570–660ºF (300–350ºC). Since the higher temperature of this range is virtually identical to the final boiling point of diesel fuel, the upgrading in the HTFT in normally limited to distillation. Such is different in the LTFT case, where the longer, wax-like, molecules need to be tailored through cracking.

In the low temperature process, the alpha for iron-based F-T synthesis is generally higher than the one for cobalt because of olefin reinsertion, [25][26] and can be as high as 0.96. The increased alpha allows for a greater production of high molecular weight hydrocarbons, i.e. wax. Therefore, the different catalysts will produce a different slate of hydrocarbons, which we can classify according to chain length or carbon number. Typical raw F-T product distributions of the iron and cobalt catalyst are summarized in the table below.

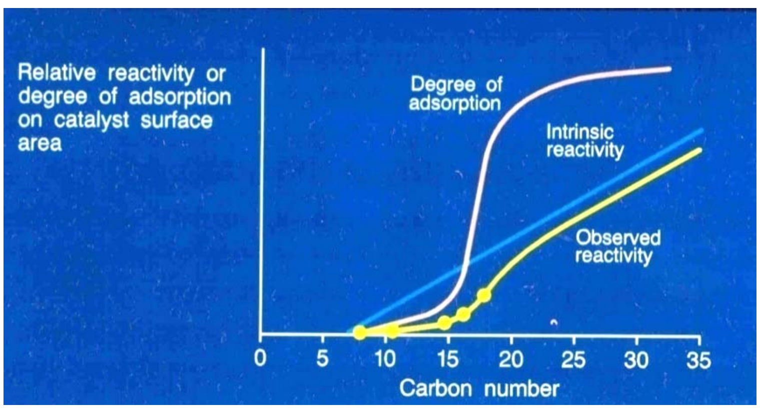
	Iron	**Cobalt**
Naphtha C_5-C_{10}	10%	15%
Kerosene and Diesel	20%	30%
Wax (C_{20}+)	60%	40%
	More Olefins	More Saturated

Catalyst versus typical raw F-T product yields

The main categories of the raw F-T product are naphtha, kerosene, diesel and wax. In the most simple process configuration, the raw F-T product is generally recovered in two fractions in order to avoid complications in the product condensers. The "heavy" F-T products are condensed at some 400 psia and 300–390ºF (150-200ºC), while the "light" F-T products are subsequently recovered by lowering the remaining F-T reactor product stream further to ambient temperature. The "light" F-T product stream is a mixture of naphtha, kerosene and diesel. This straight run material is, in general, a mixture of over 95% of linear hydrocarbons, a few percent of (mainly alpha-) iso's and around 1% of oxygenates. The linear molecular structure of this material gives it relatively poor cold flow properties.

The "heavy" F-T products are predominantly wax. This F-T wax can be hydro-isomerized/hydro-cracked to produce more distillates. For this reason, the GTL process is sometimes referred to as the middle distillate process. Shell, for example, uses the name Shell Middle Distillate Synthesis or SMDS process. Other companies have comparable names playing with the characteristics, like ExxonMobil's AGC-21 – Advanced Gas Conversion for the 21st century. The resulting cracked product, which is normally tailored to contain a substantial quantity of iso-paraffins, has obviously much better cold flow properties.

The hydro-cracking or hydro-isomerization of the heavy Fischer-Tropsch synthesis products can also be described as "mild hydro-cracking." At pressures of 1100 psi and 660ºF (350ºC), over a commercial catalyst the paraffinic molecules are easily cracked. Catalysts known in the industry are nickel-tungsten (NiWo) and noble metal (hydro-cracking/hydrogenation) catalysts. By selecting the appropriate trickle flow conditions in the hydro-cracking reactor, as little as possible of the "light" products are produced. This mechanism is well understood and described [27]. It is characterized by a combination of the mechanisms of the intrinsic reactivity of linear paraffins and the residence time of the hydrocarbon molecules on the surface of the catalyst.

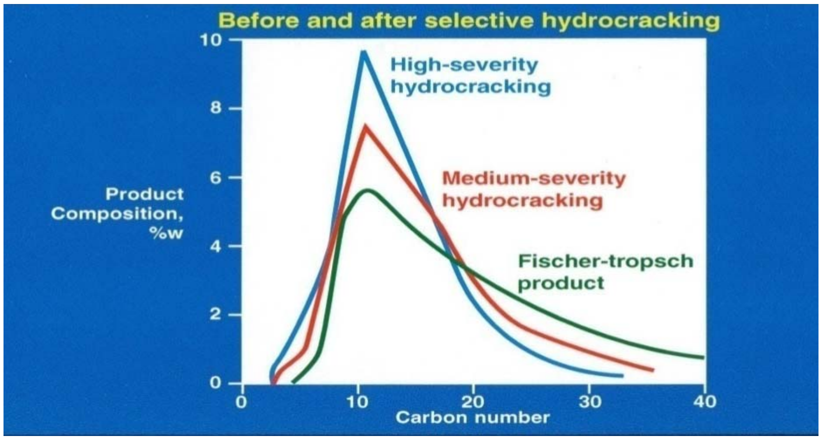


Schematic Representation of N-Paraffin Reactivity

When modeled, the hydro-cracking of F-T material almost follows the ideal cracking rules:

- Heaviest feed component cracks first
- Primary cracking only - 1 reactant molecule to 2 product molecules
- Follows the ideal C-C scission probability observed for a paraffin molecule

The application of the hydro-cracking/hydro-isomerization technology allows for maximization of the distillate yield. By selection of the operating conditions of the cracking process, it also gives a limited degree of freedom in determining the product yield. In general, one can state that milder operating conditions result in relatively longer molecules and hence, the higher the diesel yield.



Carbon Distribution of Hydro-cracked Fischer-Tropsch Product

Sometimes, distinction in this operation is made by calling it the “kerosene” or “gasoil” mode of operation of the mild hydro-cracker. Typical product distributions in those operation modes are:

	Kerosene Mode	Gasoil Mode
Naphtha	10%	15%
Kerosene	20%	25%
Diesel	70%	60%

The roots for this technology were already laid immediately after WW II. At that time, USA researchers started extensive work on upgrading processes of Fischer-Tropsch materials. Shell Oil researchers Greensfelder and Moore developed in the USA in 1946 a process to create highly branched hydrocarbons from linear paraffins, while maintaining the same molecular weight and avoiding excessive decomposition. [28]

Some typical properties for pure F-T fuels [29] are given below:

Property	Unit	Naphtha	Kerosene	Gasoil	Method
Density @ 15 ˚C	kg/m^3	690	738	780	ASTM D 1298
Saybolt color $^{1)}$		+30	+30	n/a	ASTM D 156
Distillation range IBP FBP	 ºC ºC	 43 166	 155 191	 201 358	ASTM D 86
Sulfur $^{1)}$	Ppm	n.d.	n.d.	n.d.	ASTM D 1266
Cetane number $^{1)}$		n/a	58	76	ASTM D 613
Smoke point $^{1)}$	Mm	n/a	>50	n/a	ASTM D 1322
Flash point $^{1)}$	ºC	n/a	42	88	ASTM D 93
Aromatics $^{1)}$	%v	n.d	n.d.	n.d.	ASTM D 5186

1) n.d. = not detectable/below detection limits *ppm = parts per million*
n/a = not applicable *mm = millimeter*

ASTM Dxxx = method of analysis per American Society for Testing and Materials

By their nature, products from carbon monoxide and hydrogen are extremely clean. They contain no sulfur, no nitrogen and no (detectable) aromatics. In fact, established industrial analytical methods for such contaminants do the products an injustice with the crude lower cut-off levels for their measurement ranges. The F-T products have impurities that are several orders of magnitude lower than highly refined crude oil derived products. Hence, several normal "oil-impurities" are not detectable by the standard methods. The quality of the products from the commercial plant is equal to and in several respects better than predicted on the basis of product from the pilot plant tests.

3.7 The Competition in GTL

With the aforementioned information on syngas generation, F-T processes, F-T catalysts, various reactor technologies and upgrading technology, it shall be no surprise that numerous combinations are possible. Hence there are a handful of competitors in the GTL industry, who all have found their own niche. If we limit ourselves to some of the variables, catalyst and F-T process, we can make up an initial matrix for license holders and reactor technologies:

The two commonly used catalysts for the Fischer-Tropsch reaction are iron or cobalt. The Fischer-Tropsch synthesis proceeds via two process versions: high and low temperature. The following table summarizes catalyst, process temperature and license holding company for various Fischer-Tropsch synthesis process forms: fixed bed, fluidized bed or slurry type.

Operating Temperature / Catalyst Type	**Low** Temperature (250°C or 500°F)	**High** Temperature (350°C or 700°F)
Iron	Rentech – Slurry Sasol – Fixed Bed	Sasol – Fluidized Bed
Cobalt	BP – Fixed Bed ConоnoPhillips – Slurry ENI/IFP – Slurry ExxonMobil – Slurry Lurgi/Statoil/PetroSA – Slurry Shell – Fixed Bed Syntroleum - Slurry	---

License Holding Company and F-T technology
by Catalyst Type and Operating Temperature

We will now, in alphabetical order, spend a few pages on each of the above mentioned competitors in the GTL industry, highlighting their individual achievements in the F-T technology via pilot plants and/or projects. We will for convenience highlight in bold letters the various specific technology elements of each company.

3.7.1 British Petroleum or BP (formerly BP-AMOCO-ARCO)

The BP GTL technology is a true mix of valuable contributions to the F-T technology from BP, AMOCO and ARCO. We will concentrate on British Petroleum (BP), although there was, before the merger, a center of F-T activities within the American Oil Company (AMOCO) as well. Equally, the Atlantic Richfield Company (ARCO) has been actively interested in the Syntroleum F-T technology. AMOCO conducted its Fischer-Tropsch related R&D out of its research laboratories in Naperville, Illinois. To the outside world, AMOCO's R&D had reached the scouting-level, following the industry, but never showed clear enough to break through and claim victory on any front. ARCO, on the contrary, never entered in its own F-T developments. It took a Syntroleum license and demonstrated the operation of an ebulating bed reactor in its Cherry Point refinery in Washington State.

The takeover of AMOCO by BP in 2000 (according to Lord John Browne we are only talking about BP), introduced numerous changes, including those in R&D: Naperville activities ceased and the center of GTL R&D moved to Sunbury, outside of London, U.K. BP's R&D on F-T has been going on since the mid 1980s.[30] The F-T catalyst development work led in the early 90s to pilot plant trials in their chemical complex in Hull, U.K. The original work of BP started with a ruthenium-on-carbon catalyst.[31] Disheartened by the cost of ruthenium and CO_2-intolerance of cobalt-on-carbon catalyst [31], work focused on **Co-Zinc-oxide catalysts**.[32] It culminated in the development of a supported, zinc-oxide based, promoted cobalt catalyst for operation in a **tubular reactor**. Whereas much of the initial catalyst development and manufactured was done by BP in-house,[30] commercialization of BP's catalyst is believed to have been done by Engelhard.

BP was, in an early stage of the process development, convinced of the importance of availability of cheap syngas for the economic success of gas conversion.[33] The now patented, compact reformer development started in BP Oils former research center in Warrensville, OH in 1989. Here, single tube tests and larger pilot plant tests were done. In 1996 BP entered into technology exchange and license arrangements with Davy Process Technology (DPT) to further develop the new **compact reformer system**. DPT has just recently (February 2006) been bought by Johnson Matthey, from the bankrupt Russian company Yukos. The owners before that time included Kvaerner Process Technology, Davy Power Gas and ultimately the old Humphreys & Glasgow. In that swap of expertise with BP around the compact reformer, Davy acquired the licensing rights to BPs Fischer-Tropsch technology and is now the sole point of contact for BP F-T work.[34] In itself this already shows something of BP's commitment.

With the acquisition of AMOCO and subsequently ARCO, BP was sitting on enormous gas reserves, particularly in Alaska. Something needed to be done to show the world its utilization. With all the gas conversion research and development done, BP decided to build a test Fischer-Tropsch plant in Alaska but the company never intended for a GTL process to be used on the North Slope

Sanction for a F-T Test Facility project in Nikiski, in the Cook Inlet of Southcentral Alaska, was given in July 2000. DPT, London put the process design package for the facility together and the Engineering, Procurement and Construction contract was awarded to Kvaerner, Houston. Mechanical completion was recorded in March 2002.[35] The start-up of the plant, however, was seriously delayed by problems. The seals of the syngas compressor, which is nothing more than a blower, were blamed, but there were other problems as well. As a result, the plant made its first production run, more than a year later, on July 27, 2003.[36] Rumors also have it that in the final design and due to cost cutting, more attention has been given to the compact reformer than the F-T section of the plant.

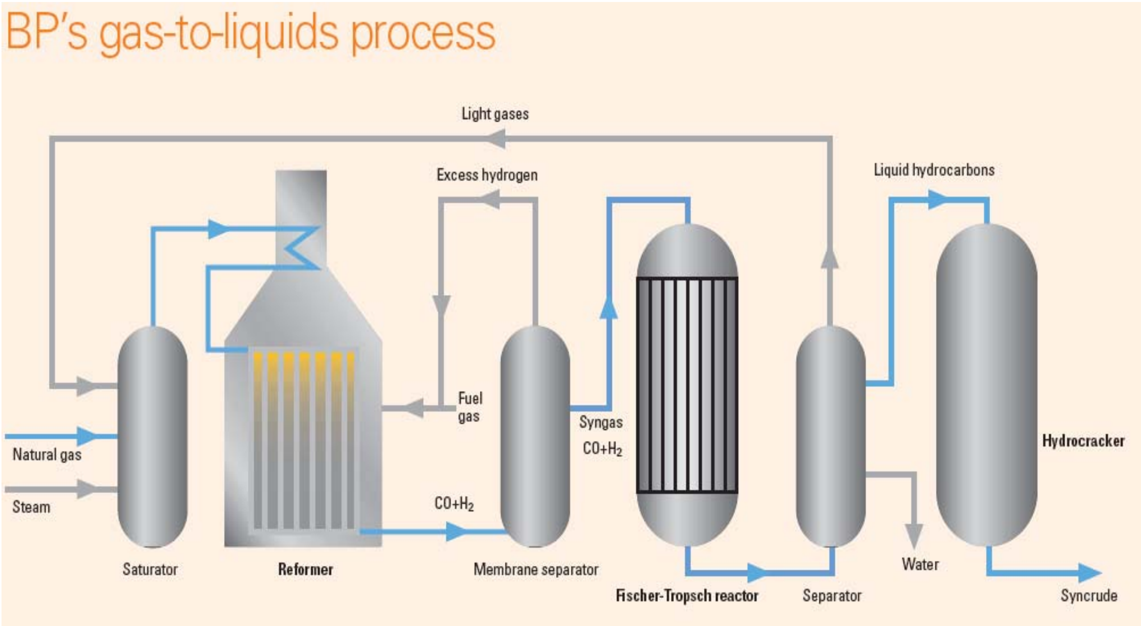
Photo courtesy: BP

The plant is located on five acres, close to the ConocoPhillips LNG plant and Tesoro Refinery, to which the "upgraded F-T reactor effluent or syn-crude" is sold to be further processed. It takes its natural gas (of very high purity) from a supply line to this LNG facility. Project costs for the Nikiski plant have been quoted to be $86 million.

The Nikiski plant in Alaska demonstrates the BP/DPT technology to convert 3 MMSCFD of natural gas to 300 bbl/d of synthetic crude.

The process consists of:

- the **compact reformer** (proprietary BP/DPT design for syngas production)
- the **multi-tubular Fischer-Tropsch converter** (proprietary BP catalyst produces paraffin wax)
- the **hydro cracker** (commercially available technology to produce syn-crude, said to use Ketjen hydro-cracker catalyst)
- **membrane unit** by Air Products and Chemicals Inc.



Picture with permission of BP Frontiers magazine, December 2002[8]

The compact reformer is interesting as it operates at an operating temperature of some 650 degrees C and elevated pressure on both the process (the F-T operating pressure of 400 psia –450 psia) and the combustion side (>280 psia is claimed). Therefore, this concept eliminates much of the stresses on the reformer tube material, often limiting the conventional reformer. The concept of the elevated pressure level has, from a process point of view, been chosen with the objective to eliminate the syngas compressor of the traditional designs. In the compact reformer, the heat is generated by burning excess hydrogen from the plants' process gas. This excess gas is extracted via an APCI supplied membrane, which also furnishes the hydrogen for the mild hydro-cracker. The reformer fuel gas is heated in coils of the compact reformer to temperatures over auto ignition, distributed over a multitude of small burner nozzles, where it rapidly mixes with pressurized air and forms a uniform burning front. This uniformly burning "tube-sheet fire front" is one of the reasons for the compactness of the reformer, as it circumvents "flame" impingement (since there is no real flame!). BP claims that the reformer works as well on natural gas, though, which through lesser diffusivity obviously presents more mixing difficulties. The carbon-dioxide loss via the reformer fuel gas obviously impacts the overall carbon efficiency of the process negatively.

As a result of the higher operating pressure and lower temperature, there is a substantial methane slip from the reformer. There is a (low compression ratio) syngas compressor/blower in the scheme (not shown in the picture) to overcome the pressure drop over the system and allows re-circulation of the unconverted syngas (including the CO_2) from the F-T reactor outlet to the front end of the reformer. In this context, the required tolerance [30] of the catalyst for CO_2 can be understood.

The F-T converter is a conventional multi-tubular reactor, having 1 inch diameter tubes.

The syn crude specification is:

API gravity	53 ^{o}
Density	760 kg/m^3
Viscosity at 104 ^{o}F	1.96 cP
Pour Point	–16 ^{o}F

Composition:

product yield	(%WT)	boiling range(^{o}F)
Naphtha	2.0	60-300
Kerosene	23.9	300-420
Gasoil	32.7	420-648
Heavy Gasoil	3.4	648-696
Residue	19.8	>696

3.7.2 CONOCOPHILLIPS

ConocoPhillips is one of the more recent players in the F-T field. ConocoPhillips was formed from a couple of colorful companies. Phillips, one of the parent companies, was one of the early players in active marketing of natural gas and the ventures around its transportation. In the early days, when F-T was still considered to be in its infancy, they concentrated on LNG. With their proprietary LNG technology, Phillips placed themselves proudly on the map of LNG producers. Phillips' main success, and, important moneymaker, is the Kenai LNG facility in Alaska, at the time the third LNG facility in the world. So, in essence, Phillips had no heritage in F-T technology at all. Conoco, to the contrary, had made an active entry in the natural gas conversion and transportation sector, in part based on extensive expertise inherited from its former parent DuPont. When DuPont bought petroleum manufacturer Conoco, Inc. in 1981, it was the largest merger in corporate history. The purchase gave DuPont a secure source of gas and petroleum feedstock needed for many of its fiber and plastics operations. Conoco also manufactured profitable commercial petroleum products and coal, produced by the wholly owned subsidiary Consolidated Coal Company. The purchase gave Conoco access to DuPont's extensive expertise in catalysis.

In this setting, Paul Grimmer, Conoco's Manager Diversified Businesses, convinced his management in 1997 of the importance of the GTL technology in terms of access to new and transportability of the natural gas resources. After a detailed market analysis, they identified 173 gas fields with reserves larger than 3 trillion cubic feet (Tcf) each. Ninety fields of those were considered to have "reasonable" economics. Also, through process and economic reviews, Grimmer demonstrated the fact that **lower cost syngas** was critical to the success of GTL technology. Conoco endorsed this line of thinking and on this basis a team of scientists and engineers designed, manufactured, and tested various reactor configurations and more than 4,500 catalysts. That the Conoco team worked hard at the development may be illustrated by the fact that in 2001 they had 7 reformers and 23 different F-T reactors in operation.

Since the separation of Conoco and DuPont in 1998, when DuPont sold all of its Conoco shares in order to free up capital for investment in other businesses, the Gas-to-Liquid business became solely Conoco's. All the equipment and technology/scientists were moved to Conoco's Ponca City, Oklahoma Research and Development facilities. It was housed in the large R&D West building, constructed there in 1980–1981, prior to Conoco's merger with DuPont. Conoco pushed even harder: Staff peaked in late 2002 to little over 200, about half of whom were scientists and engineers, most with advanced degrees.

Conoco developed novel technology for syngas generation, its Catalytic Partial Oxidation or so-called CoPOx® technology. They developed proprietary F-T synthesis in slurry bubble column operation and hydro-processing that enables a higher efficiency process through intensive process integration. Since 2002, the GTL process, to be referred to as ConocoPhillips, thus uses oxygen and natural gas as feedstock to produce premium diesel and naphtha. Since the merger, also the abbreviation of the Conoco catalytic partial oxidation technology, CoPOx, changed to COPox™, to reflect the stock market ticker symbol (COP) of ConocoPhillips. The ConocoPhillips GTL process uses proprietary catalysts in the synthesis, Fischer-Tropsch and hydro-cracking, processes.

After several years of research, plans were announced to build a $75 million, 400 bbl/d demonstration plant in Ponca City to convert 4 MMSCFD of pipeline gas and to commercialize the company's technology. This indicates an earnest commitment to this effort. Bateman Engineering was retained to do the Front End Engineering Design (FEED), which resulted in a layout with two identical – full 400 bbl/d- COPox, two F-T slurry units of 200 bbl/d each and a common product work-up section. The "semi-works" plant was mechanically completed in April 2003 and commissioned to have its first gas intake in September 2003 to convert gas into 400 barrels per day of sulfur-free diesel, jet fuel and other products.

ConocoPhillips GTL Plant Picture 2003

Conoco GTL Plant Artist Impression 2002

The plant, depicted in a photograph from 2003 above, is in good comparison with the artist impression, shown by Grimmer in 2002, with the artist impression showing an even better view of the distillation columns.

During the pilot plant development and construction, Conoco started negotiating to commercialize the technology in various locations. On December 8, 2003, Qatar Petroleum and ConocoPhillips announced the signing of a Statement of Intent (SOI) regarding the construction of a 160,000 bbl/d GTL plant in Ras Laffan, Qatar. The agreement was signed by His

Excellency Abdulla Bin Hamad Al-Attiyah, Second Deputy Prime Minister, and Minister of Energy and Industry of Qatar on behalf of Qatar Petroleum, and by Mr. Jim Mulva, ConocoPhillips' President and CEO. The SOI initiates detailed technical and commercial pre-FEED studies and establishes principles for negotiating a Heads of Agreement for an integrated reservoir-to-market GTL project. ConocoPhillips stated it was to be committed to meeting the goals set out in the Statement of Intent and looked forward to more definitive agreements in 2004. The first phase of 80,000 bbl/d would cost about $1.5 billion and scheduled come on-stream by 2009–2010. The second phase, which will double the capacity, will raise total costs to $5 billion. The production-sharing contract represents the fourth GTL project secured by Qatar Petroleum (Sasol-ORYX, March 2001, ExxonMobil - June 2001, Shell - February 2002), putting the Gulf Arab state on track towards its goal of becoming the world GTL capital by 2010.

With few of the projects already under construction in Qatar, a raising concern about the logistics developed. It led early on to the speculation that one or more of the announced projects would not even make it, or that some of them were to be significantly delayed. In actual fact, at the gas conference in Port of Spain, April 26, 2005, Abdullah bin Hamad Al Attiyah, the Qatar Energy Minister announced the delay of the Phillips-Conoco project for up to three years. ConocoPhillips' response has been silent since then.

3.7.3 ENI-IFP

A relatively new player in the F-T field is the ENI-IFP group, although ENI has a long-standing, and one could say pioneering, history in natural gas. ENI [37] is the acronym for the Italian State company Ente Nazionale Idrocarburi. The company finds it basis in AGIP (Azienda Generale Italiana Petroli or Italian General Oil Company), which was established in 1926 and is the Italian State company responsible for drilling in Italy for oil and gas. AGIP entered into the refining and petrochemical business in 1936 and made the Podenzano gas discovery in the Po Valley. This sparked its gas and pipeline business, which found its identity in 1941 in the Ente Nazionale Metano, Agip, Salsomaggiore Regie Terme and Surgi spin-off/merger to become the Società Nazionale Metanodotti (Snam). To date, we still know Snamprogetti as the Italian (engineering) company to construct and operate pipelines.

In a post WWII reorganization, Enrico Mattei was appointed as AGIP's Special Administrator in 1945. His task was to secure the supply of energy to Italy, as a country increasingly dependent on imported oil and with only natural gas as a major indigenous resource. Mattei recognized the importance of natural gas and made it the basis of Italy's industrial development. The vehicle to achieve this is ENI, which he established in 1953. Enrico Mattei became the first chairman of ENI.

For the longest time, ENI had no position and/or interest in the conversion of natural gas (or LNG for that matter). This changed with Pierpaolo Garibaldi and Peter Schwartz at the helm of EniTechnologie and of ENIs research division, Eniricerche, respectively. A clear interest in Fischer-Tropsch technology and change of directions developed. ENI started their own F-T R&D, but instead of entirely reinventing the wheel, Garibaldi and Schwartz quickly realized that their relative position in the F-T world could only be improved by picking up a partner. A hook up with the long-time player Institute Français de Petrol (IFP) was the result.

To put IFP [38] in perspective, IFP is an independent scientific research and industrial development center, also doing training and information services. IFP is active in the fields of oil and natural gas, their use, in particular by vehicles, and new energy and environmental technologies (production of fuels from biomass, biofuels, hydrogen, the capture and storage of CO_2, etc.). IFP is a center of innovation. IFP has a portfolio of 12,000 in force patents and each year files more than 950 patent applications in France and abroad [39]. This made IFP the 10th most prolific French applicant of patents in France in 2002, and according to figures taken from the Patent Intelligence & Technology Report, and the fifth largest French patent-holder in the United States in 2003.

Strategic R&D has long been the trademark of IFP, where Patrick Chaumette championed the Fischer-Tropsch R&D. Numerous papers, presentations and patents are credited to him and his co-workers.[40] [41] Besides being a R&D organization, IFP has an industrial development section with an interesting portfolio of investments: IFP hold 7% in engineering company Technip-Coflexip (who built the Statoil-PetroSA slurry F-T pilot plant in Mossel Bay); it is full owner of Axens, **the hydro-cracker** and catalyst company; it also holds 50% in Eurecat, the catalyst handling and regeneration company (said to have loaded the reactor of the BP Nikiski pilot plant). In all, IFP controls R&D, patents and an interesting mix of companies, which in one way or another are related with the F-T industry and have (potential) access to various F-T experiences.

In 1996 [42]**,** ENI and Institut Francais du Petrol decided to join their efforts for the development of a GTL technology, on the basis of the synergy existing between the two partners: on the one side ENI, heavily involved in the production, transportation and trading of natural gas in many geographic areas, on the other IFP, with a worldwide reputation for licensing process technologies in refining and petro-chemistry. As soon as the GTL technology started to show its potential for industrial application, the two companies joined efforts in this field to get benefits from the skills in catalysis, process engineering and technology development present in both companies and thus reduce the time to completion, the costs and the risk to reach such a challenging target. A strategy was soon adopted for this project, aimed at reducing the technical risk on the one hand, and to maximize the two companies' technical assets on the other: it was chosen not to develop another synthesis gas technology, but to resort to the market for its deployment and, together with the F-T, also the development of a tailor-made hydro-cracking technology was started. In a period of five to six years, a novel generation F-T catalyst was developed, a **proprietary slurry reactor** designed, a **dedicated hydro-cracking technology** optimized and efforts dedicated to the optimization of an integrated process scheme. As with every technology development, this included attention to scale-up issues, including testing at laboratory and bench scale of the reactor technology, also by using dedicated mock ups, and of the other ancillary sections. The conventional slate of products is constituted by a virgin naphtha cut, a kerosene fraction and a diesel fraction all of very high quality. On special needs, lube base stocks or other products.

In addition, a wide array of fundamental studies have been carried out with the purpose of mastering the understanding of the complex physicochemical phenomena relating catalyst behavior under reacting conditions, gas and liquid flows in the reactor, and the challenge of the high heat release. In 1999, it was decided to proceed with the completion of the know how in this field through the design and construction of a pilot plant aimed at carrying out the R&D at a proper scale.

Just like R&D projects in the United States have been supported by the Department of Energy, European R&D can be supported by public authorities in the European Union. The IFP and Agip Petroli project to develop a high-performance Fischer-Tropsch process was partially funded by the European Thermie and Eureka programs. It led to the construction of a pilot installation with a nominal capacity of 20 bbl/day of hydrocarbons, designed and built with the help of Zeton Inc. of Burlington, Canada. The unit was started up in November 2001 in the ENI's refinery of Sannazzaro de Burgondi (Pavia), and since then has been operated for testing different proprietary catalyst formulations and process conditions.[43].

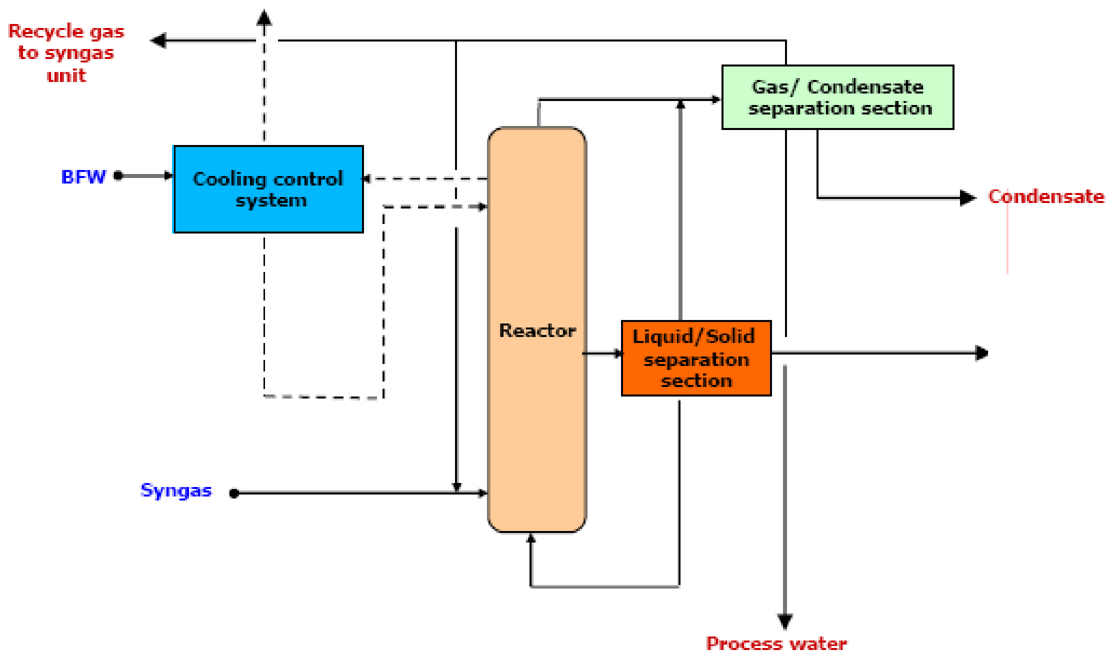

(Photo: Courtesy ENI-IFP-Axens)

The pilot plant is reportedly[44] using methanol as feedstock.
The reformed methanol is reformed according to

$$CH_3OH \leftrightarrow CO + 2H_2$$

to give 2,200 Nm^3/h, about three times the volume needed for the nominal 20 bbl/d F-T slurry bubble column. The pilot plant facilities (interconnection with the adjacent refinery for additional SMR syngas or use of a membrane unit) reportedly allow for H_2/CO adjustment. This syngas feed, combined with the process scheme of the pilot plant, does suggest the design for a state-of-the-art F-T cobalt catalyst, with roughly 30%–40% conversion per pass.

(Photo courtesy Zenarro [44].)



ENI-IFP pilot plant process flow scheme (picture courtesy: ENI-IFP)

The catalyst in use is a **cobalt-on-silica carrier catalyst**. Two versions have been patented: $Co/Mo/W/K/Na/SiO_2$[45], and $Co/Ru/Cu/K/Sr/SiO_2$ [46] [47] The latter one is the most likely candidate used in the pilot plant.

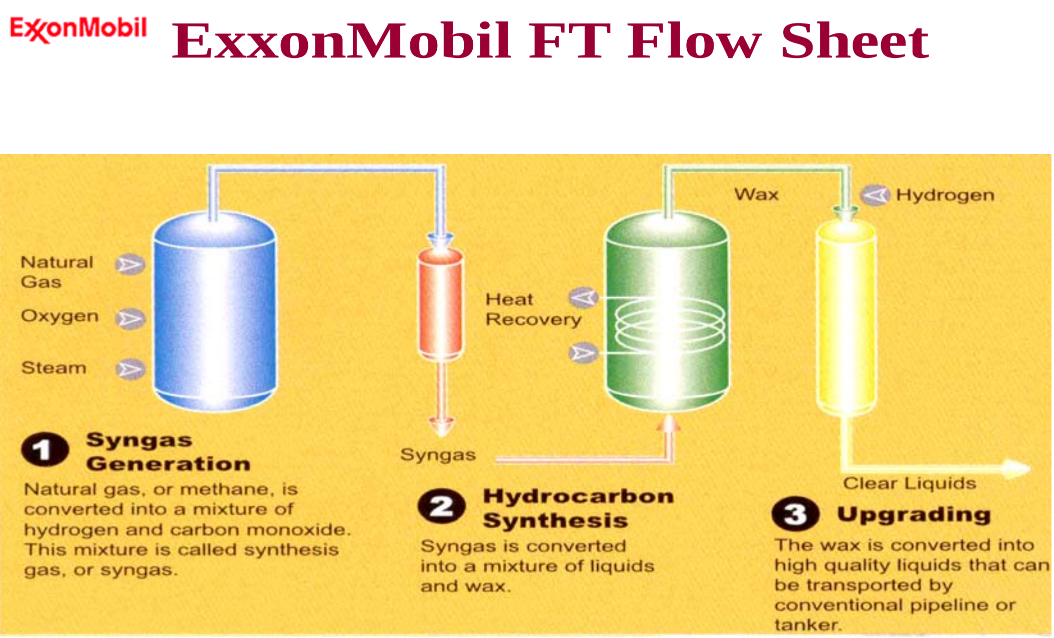
Regarding intellectual property, both ENI and IFP have an extensive patent portfolio. We already referred to IFP's leadership in patenting. The ENI-IFP Fischer-Tropsch technology is considered to be proprietary and only accessible to those projects where ENI-IFP are project participants.

3.7.4 ExxonMobil

The merger between Exxon and Mobil to ExxonMobil [48] has put together two companies who have and are still playing an important role in the GTL industry. Mobil's contribution in the Fischer-Tropsch arena has been limited to exploratory/scouting R&D and pilot plant work by Jim Kuo et al. during the 1980s, particularly on the (iron) catalysis side in a slurry bubble column. Their main contribution to the synthetic fuels industry has been through the development of the Methanol to Gasoline (MTG) process [49], which was commercialized in 1985 in Motunui, New Zealand. In this process, Mobil's zeolite catalyst (ZSM-5) enabled a natural gas to gasoline project that operated until 1997, producing about 14,000 bbl/d synthetic gasoline. In 1997, the plant was procured by Methanex to produce methanol. Also, Mobil's strong position in lube oils and catalytic wax upgrading technology make ExxonMobil, from a product perspective, a strong contender in the GTL industry.

The ExxonMobil Advanced Gas Conversion technology for the 21st century (AGC21) has been developed since the first oil crisis in 1973. Its main characteristics are:

- **Syngas generation in a fluidized bed**. This is based on ExxonMobil's strong position in fluidized bed FCC technology (recently, though, ExxonMobil has portrayed the use of fixed bed **SMR technology** in their proposed Qatar project). The ExxonMobil syngas generation technology uses mild partial oxidation in the top of the fluidized bed followed by steam reforming reactions in the bottom of the same fluidized bed reactor.
- **Slurry Bubble Column Reactor (SBCR) technology for Fischer-Tropsch**.
- **Hydro-cracking/hydro-isomerization** of the F-T waxy product.
- Use of a **cobalt F-T catalyst on a spherical zirconium-oxide (ZrO) support**.



The primary catalyst inventors in the early 70s were Dr. Soled and Dr. Iglesia. They are referenced in some 400 patents, many of which are co-authored by Dr. Fiato. Dr. Iglesia retired from Exxon and is currently active as a professor in Berkley, CA. ExxonMobil's catalyst development led to the so-called "thin-layer," also called "rim-loaded" or "egg-shell" catalyst. [50] In this concept, the eggshell can be visualized as a catalyst sphere with several consecutive concentric outer-layers. In these outer-layers, the cobalt has a concentration gradient so that the cobalt loading varies from high on the outside to nil inside the particle. The ExxonMobil patent on this subject claims higher liquid hydrocarbon productivity of the "egg-shell" catalyst. This is, in turn, contributed to lower methane make due to avoiding:

- diffusion related increase in the H_2/CO ratio
- catalyst particle overheating

In order to demonstrate their technology, ExxonMobil built a 200 bbl/d pilot plant in their Baton Rouge refinery. The pilot plant, which was erected for $400 million, was operational in integrated configuration (i.e. simultaneous syngas generation, F-T and hydro-isomerization) for two years and mothballed in 1990. Dr. Richard Bauman, who managed the ExxonMobil pilot plant for many years, deserves lots of credit for the development of the proprietary ExxonMobil AGC21 technology.

ExxonMobil Pilot Plant–Baton Rouge

Photo: Courtesy ExxonMobil

On the project side, ExxonMobil Corporation Qatar Petroleum announced the signing of a "Letter of Intent" to conduct a technical feasibility study for a world-scale Gas-to-Liquids plant in Qatar on June 15, 2001. The plant capacity is quoted to be 154,000 bbl/d. The project, which is to be owned by an ExxonMobil/QPC Joint Venture (49%-51% ownership) targets the exploitation of the giant North Field, offshore Qatar. When the first contract between ExxonMobil and Qatar was signed, investment costs for the plant were reported to be $7 billion, the single largest investment in ExxonMobil's history**.** The plant was expected to come on stream in 2011. As the escalation of costs in the industry, and in the Middle East in particular, did not escape ExxonMobil the project was in February 2007 deferred to later execution.

3.7.5 PETROSA (formerly MOSSGAS)

Mossgas, the South African state-owned gas-to-liquids producer, was formed in 1987 as a subsidiary of the South African Parastatal Central Energy Fund (CEF). [51] Its creation followed the discovery of gas in Mossel Bay, offshore, east of Cape Town. The first discovery there was made in 1969 in the so-called FA field. At that time, the South African government was very much involved in the production of transportation fuels from coal via SASOL. In July 2000, a merger between Mossgas and other government oil and gas-related entities was initiated to form The Petroleum Oil and Gas Corporation of South Africa (Pty) (PetroSA). The company was established in 2002 through the merger of three state-owned entities: Soekor (an exploration company); Mossgas (a GTL liquids and condensate refinery) and activities related to the Strategic Fuel Fund (SFF). PetroSA, still a wholly owned subsidiary of CEF (Pty) Ltd, was formed in order to effectively develop and exploit the crude oil and gaseous hydrocarbon resources of South Africa.

With the discovery of offshore natural gas in the aforementioned FA field, the first real gas find in South Africa, another route opened and Mossgas would be the vehicle to exploit this, particularly when more gas was discovered. The EM and satellite gas fields, situated 30 miles west of the FA field in the Bredasdorp Basin Block 9, were discovered in 1984 and tested 10 million standard cubic feet per day (MMSCFD in early Cretaceous sands. The new reserves were estimated at 600 billion cubic feet (BCF) to provide a GTL facility with sufficient supply until 2007. In 1985, a first feasibility study was done followed by detailed engineering, and with the results of this in 1987 the Mossgas GTL project was sanctioned. The project configuration is:

- Offshore platform and gas/condensate gathering.
- Two pipelines to onshore, one for wet gas and one for condensate.
- The GTL plant.
- The permanent facilities inside the boundary fence.
- A tank farm with a 2 km sub-sea pipeline to transport products to a conventional buoy mooring for loading into tank ships.

PetroSA GTL Plant Overview

The GTL plant layout consists of:

- Onshore gas/liquids separation.
- Three **steam methane reformers with additional Auto Thermal Reforming (ATR)** for syngas generation.
- Three **Synthol fluidized bed F-T reactors** (in license from SASOL).
- **Olefin oligomerization** of the unsaturated hydrocarbons from the Synthol reactor.
- **Distillation** of the various hydrocarbon fractions.
- Alcohol recovery from the F-T water fraction.
- A mini refinery complex for further upgrading of the hydrocarbon fuels.
- Utilities and plant tank farm.

The EPC contract for the onshore facilities was awarded to CB&I John Brown Ltd of London, U.K. in October 1987 and ready for start up in July 1992

To get an impression of the workforce and manpower requirements for such a project, CB&I John Brown provided the following data: 265 site staff was employed at peak, with an additional 15 procurement staff in the Johannesburg home office; 16,000 people were working on site at peak for some 34 contractors

From the above, it should be clear that the Mossgas project is completely geared to transportation fuels and no specialties. This is an explicit part of the license given by SASOL, who wanted no competition in this high added-value market. Its motor fuels are supplied to the local oil companies, which market the products under their own brand names in large parts of the Western, Eastern and Northern Cape provinces. The EPC contract was awarded to CB&I John Brown Ltd of London, U.K., in October 1987 and ready for start up in July 1992.

PetroSA Synthol Plant

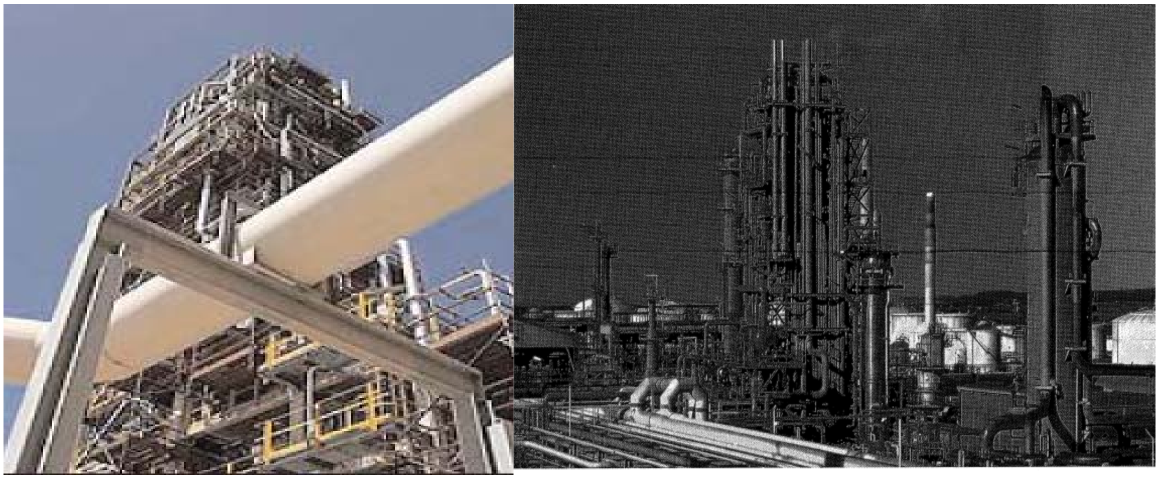
The project, as is usual for a one off grass-roots one, had a difficult delivery: its start-up was initiated in 1991. By January 1993, operation of three trains was achieved. By mid-1993, the project was declared a technical success, but the bill was high: U.S. $4 billion for 22,000 bbl/d of F-T product and 10,000 bbl/d of condensate to be processed into 32,000 bbl/d transportation fuels.

[Comment: Lately some sources are quoting the GTL facility as 45,000 bbl/d. Whatever the capacity is, to put costs in perspective, the U.S. $4 billion capital investment and a capacity of 32,000 bbl/d corresponds to the traditional oil finding costs for oil companies of U.S.$ 17-18 per barrel, which in current days is still competitive with the oil finding costs of many oil companies].

Since then, the Mossgas project has technically been a very successful one, with an impressive record of availability. Of all the equipment on site, the waste heat recovery boilers of the combined reformers have been the main cause of plant shutdown. Its cause has been, in most likelihoodhood, traced back to the use of poor boiler feed water quality. These steam boilers were replaced in 1995/96 and again in the second half of 2003. [52] On the economical side, there have always been rumors about the non-availability of gas to give the plant sufficient life. In the late 1990s, there were rumors about the plant being for sale to interested parties who wanted to convert the plant to methanol or petrochemicals. [53] Development of the EM gas field offshore, which made its first gas delivery in 2000, have quieted these rumors.

Besides Fischer-Tropsch technology, Mossgas also uses the Conversion of Olefins to Diesel (COD) process using a Süd Chemie oligomerization catalyst on a zeolites base material for the conversion of the light olefins from the F-T synthesis to low aromatics distillate transportation fuels. In 2001, they awarded the engineering, procurement and construction contract for a R135 million (U.S. $16.8 million) plant to Foster Wheeler South Africa. The plant, which is built on Mossgas' existing premises at Mossel Bay, produces 70,000 tons of environmentally friendly low aromatic diesel and kerosene per annum for the export market. The project included the construction of a low aromatic distillate production facility and new tanks at the Mossgas refinery as well as at Mossgas Voorbaai tank farm. The plant went into production in October 2002. Institut Français du Petrol gave the process license for the project. The products are synthesized from a range of olefins and are essentially odorless, colorless, smokeless and sulfur-free. The low aromatic products are expected to command substantial premiums over the local fuel price of diesel and kerosene. The American and European markets for drilling fluids, solvents, specialty chemicals and indoor heating and lighting are the main product outlets. [54]

In 2001, Mossgas formed an alliance with Statoil, the Norwegian State Oil Company, with the intention to build a 1,000 bbl/d slurry phase F-T unit geared to produce specialty fuels and distillates at the Mossgas site. This is a strategic partnership whereby the two companies will demonstrate and later commercially develop gas-to-liquids projects using Statoil's proprietary, cobalt-based catalyst, Fischer-Tropsch (F-T) slurry technology. [55] The entrance into the cobalt F-T catalysis is seen by some as Mossgas' way to get around their SASOL license limitations. In June 2002, they awarded a construction contract for U.S. $73 Million to Technip-Coflexip. [56] In 2004, Lurgi AG joined the cooperation. Meanwhile (see below), Mossgas had become PetroSA and the interests in the joint venture became PetroSA 37.5%, Statoil 37.5% and Lurgi 25%. The plant was mechanically completed in March of 2004. Feedstock was taken into the facility on April 19, 2004. [57]



PetroSA-Statoil-Lurgi demonstration GTL plant (Photo courtesy Statoil)

In May 2004, when synthetic oil and wax production began, the plant's output was reportedly at 50% of capacity. [58] The first run, however, only lasted five days. Although no apparent reasons were given, rumors have it that, in the start-up, the catalyst, manufactured by Johnson Matthey, had pulverized, impairing the operation of the catalyst/wax separation in the cyclones. In private communications with Statoil, it was mentioned that a second short run in 2004 to test startup conditions was made as well as a long run in 2005 after short runs had successfully demonstrated a possible operating window. In most recent (January 2006) bulletin [59] on this slurry phase F-T technology, it was stated that the PetroSA, Statoil, Lurgi, joint venture is ready to license this technology. A press communication was released on October 11, 2006, announcing the name of the consortium, called GTL.F1. It also announced that the Fischer-Tropsch Semi-Commercial Plant had been successfully demonstrated by GTL.F1 in South Africa.[60] The press release mentions continuous improvements of the technology without detailing any licensing.

3.7.6 RENTECH

Rentech was incorporated in 1981, combining the catalysis expertise of Dr. Chuck Benham and the engineering expertise of Dr. Mark Bohn. The company developed further with the commercial expertise of Dennis Yakobson (CEO) and Ron Butz (COO). Dr. Benham and Dr. Bohn had been previously involved in F-T activities in the Solar Energy Research Institute (SERI) of Golden, CO (now National Renewable Energy Laboratories - NREL). SERI had been involved in R&D to process and convert waste/biomass to diesel via F-T. They had investigated steam pyrolysis of biomass to syngas and F-T technology using fixed bed reactors with cobalt and iron catalysts.

From the beginning, Rentech [61] concentrated on a **precipitated iron catalyst** and the **slurry bubble column reactor (SBCR)** as F-T reactor. Their first pilot plant (1982) was a full syngas generation/F-T system: syngas produced from bottled natural gas via a single tube steam reformer could be adjusted in H2/CO ratio by CO_2 addition. The latter was made possible by using a Benfield CO_2 removal unit. Two slurry reactors—one being a 3.5" diameter by 11' high, and a 6"diameter by 8' high—were available. This unit, also known as their Sterling pilot plant, was campaign-wise operational until 1986.

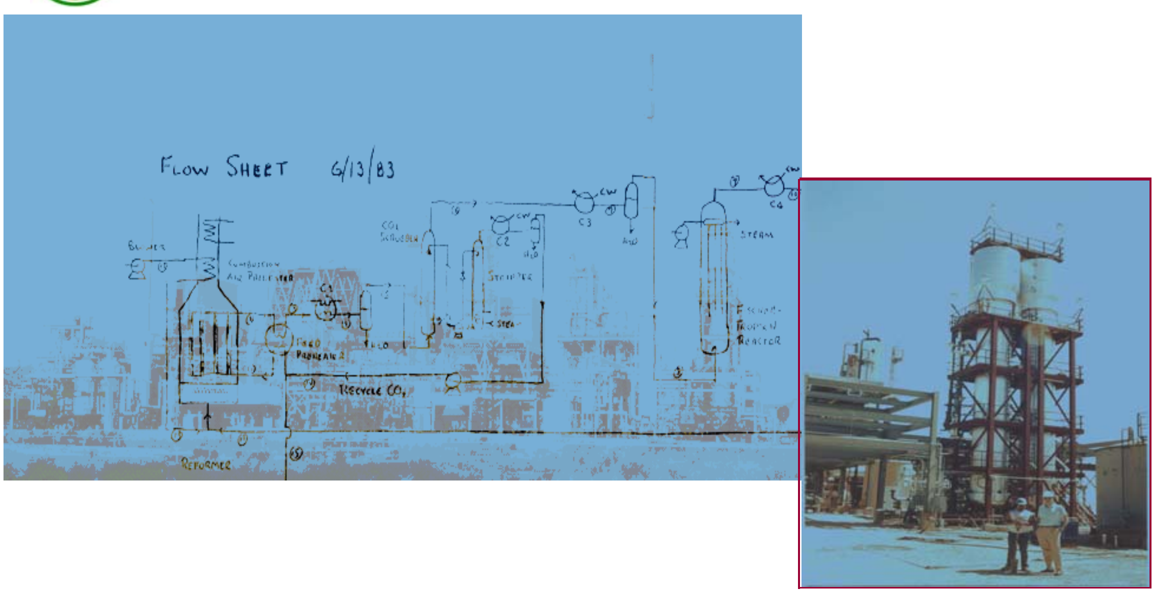
Rentech's second pilot plant was built in co-operation with Public Service Co (PSCo) of Colorado (the Denver regional electricity supplier). It was named the Zuni plant, after its location at the Zuni power station and operated by PSCo's subsidiary Fuel Resources Development Company ("Fuelco").

A third pilot plant was built in conjunction with the production of Rentech's iron catalyst. Although Rentech developed the recipe for the precipitated iron catalyst, they never entered in the catalyst production themselves. Instead, the material was toll produced by Hauser of Boulder, Colorado. For quality control, a F-T pilot plant was required, co-located with the production facility. The Boulder pilot plant (F-T reactor: 1.5" diameter by 26' high) operated from 1990 to 1993 in conjunction with catalyst production. Later it was moved to Pueblo, Colorado, and is presently operational in Rentech's laboratory in Aurora, Colorado.

Supported with government funding, Fuelco, under Rentech's license constructed in 1990–92 a 235 bbl/d demonstration plant in Pueblo, Colorado, designed for operation on landfill gas. The plant, dubbed Synhytech plant encompassed the total of syngas generation (SMR), CO_2 removal and two SBCRs. With 6' diameter by 55' high these were at the time the largest SBCRs to demonstrate slurry F-T operation. Unfortunately, the landfill cap broke, the decomposition gas got into contact with the air, so that volume and composition were not as projected. At this point, PSCo disowned itself from the project and Rentech became, in exchange release of claims, owner of the Synhytech plant and peripheral catalyst facilities in Boulder. After the feed gas supply to the unit was connected to the local natural gas grid, the plant ran for a very limited time and was mothballed. It is believed that the slurry bubble column process, as designed, was never fully proven. In 1995, the equipment was sold to Donyi Polo Petrochemical in Arunachal Pradesh, India, and shipped in 1996 to India. An intended rebuilding and re-start of the equipment was never completed.

A picture of the plant and its large SBCRs is shown below. In talks, Dennis Yakobson always made a point of showing the similarity of the 1983 flow scheme versus the 1993 plant.

Pueblo Synhytech Plant - 1993



On the project side, Rentech and a partner acquired the mothballed Sand Creek methanol plant located in Commerce City, Colorado. Rentech's objective was to convert a syngas/methanol facility to an integrated F-T plant at minimal costs. After the engineering was completed in 2000, harsh winter conditions in Colorado drove up natural gas demand and price (up to $9.00/MMBtu), which rendered the project uneconomical. With high gas demand in the Denver area, not only price, but gas availability also became an issue. As a result, the project of "the first commercial Fischer-Tropsch plant in the USA" was cancelled and the plant was put on the market for sale. After being eye-balled by various entrepreneurs, Rentech itself procured the remaining 50% of the plant from its partner for $1.4 million in October 2005. Simultaneously, they announced further development plans for the site, vested under Sand Creek Energy, LLC (SCE). [62] These plans were further worked out in a press release of December 2005[63], which made clear that the methanol plant equipment was sold (to Louisiana Chemical Equipment Company). Demolition of the plant took place in February and March of 2006. Plans were approved by the authorities of Commerce City to build a 10 bbl/d process development unit (PDU). Zeton Inc of Canada was contracted as constructor of the F-T and upgrading facility. Major process equipment was ordered by end 2005. [63] A gasifier from BioConversion Technology, LLC capable of processing 25 tons–35 tons per day of coal will provide the synthesis gas. Rentech will primarily process eastern and western coal at the facility with the capability to also process petroleum coke as well as biomass. The SCE plant will produce ultra-clean diesel and aviation fuels and naphtha from various domestic coals, petroleum coke and biomass feedstock on a demonstration scale. The products from the plant are intended to provide for supply of test quantities of these synthetic fuels to groups (Department of Defense, State and metropolitan entities), which have expressed interest in acquiring commercial quantities of Rentech's fuels.

Artist Impression of the Rentech Commerce City PDU [64]

Rentech expressed expectations to have the PDU to be mechanically complete by the end of 2006 and to be the first Coal-to-Liquids project in the country to capitalize on the tax credits available for commercialization of this technology under the new *Energy Act*.

We will give Rentech credit for their efforts and development of the technology. The Klepper gasifier had been under development for some time and made its way to Canada in a 15 tons/day version. The Rentech design requires the larger capacity of almost 50 ton/day and here again scale-up is an issue. Although the 15 tons/day unit seems to be running, the scale-up Rentech version seems to have considerable problems. On 17 October 2007, the following picture of the plant was taken. As seen, the plant is still under modifications and seemingly not operational while all other facilities seem to be there. From the picture, one can see the gasifier and its feed systems in the front.

The analyst of F-T technologies would look at the above picture and declare:

The reactor seems to be scaled to the old version of the Boulder pilot plant (slurry F-T reactor: 1.5” diameter by 26” high) operated from 1990 to 1993 in conjunction with catalyst production. However, looking closer at the perpetrations of the reactor, one might assume that multi-stage cooling is applied, as well as overhead condensing/refluxing. In the hope that Rentech really does understand the scale-up of slurry reactors, they have at least created themselves a nice R&D tool. Looking more closely at the picture, one can see the primary catalyst wax phase separator as well as two catalyst/wax separation devices. Also evident is the stack in the middle of the back-ground of the picture. It seems that Rentech has secured its syngas position by having a “Howe-Baker” cylindrical steam methane reformer on site, as back up reformer for the (as yet failing) Klepper coal/biomass gasifier.

3.7.7 SASOL

Although SASOL started producing oil from coal in 1955, its origins can be traced back to 1895 when coal was first mined on both sides of the Vaal River near Vereeniging. The mining house, Anglovaal, was interested in the large deposits of low-grade coal in this area and further south in the Free State. There was considerable interest in coal chemistry during the 1920s, and in 1927 a Government White Paper was published recommending the development of gasification and carbonization processes. In the early 1930s, Anglovaal and the British Burmah Company established the South African Torbanite Mining and Refining Company (SATMAR) to mine oil shales near Ermelo, to distill off and refine the oil, mainly for petrol. Anglovaal's interests in oil-from-coal were extended when rights to the German Fischer-Tropsch process were acquired. In 1938, Hendrik van Eck, Anglovaal's consulting chemical engineer, appointed Etienne Rousseau as research engineer at SATMAR to pursue this initiative. Franz Fischer visited South Africa in 1938 to assist in getting the venture off the ground. However, World War II intervened.

During the war, Anglovaal maintained its interest in oil-from-coal and entered into negotiations with the M.W. Kellogg Corporation. There was considerable interest in the USA at that time with the U.S. government considering an oil-from-coal plant, dubbed the Hydrocol plant. In 1945, Anglovaal applied to the South African Government for assistance to establish a plant based on the American Hydrocol technology. After protracted negotiations, a license was finally issued in 1949. Because of devaluation and involvement with gold mining developments, Anglovaal needed assistance to raise the required £20 million. The World Bank expressed polite interest in the project but no money was forthcoming.

In the meantime, negotiations were proceeding with the Kellogg Corporation for licensing of its patents and assistance in the design and erection of a plant. However, Rousseau believed that a closer look needed to be taken at what the Germans had been doing with the Fischer-Tropsch process since the war. An important aspect in the development of the South African – German contacts was the fact that South Africa's neighboring country, Namibia, was a German colony with access to the German technology and engineering. Rousseau obtained an offer from the Lurgi Gesellschaft, Oberhausen-Holten, and Ruhrchemie Aktiengesellschaft, through a co-operation. (The German word for co-operation is Arbeits Gemeinschaft; interestingly the abbreviation of this, ARGE, was used to name the F-T reactors). The offer was for the designs and the right to operate plants for the production of synthesis gas from coal and the Fischer-Tropsch process. The low temperature Fischer-Tropsch ARGE reactors, with a capacity of 500 bbl/d, were **fixed bed multi-tubular reactors**, developed during the last phase of World War II. The upshot was the establishment, on 26 September 1950, of the Government-sponsored South African Coal, Oil and Gas Corporation Ltd., commonly called SASOL. This acronym arose from Rousseau's initial suggestion that the company be called South African Synthetic Oil Limited, in Afrikaans, the local language: Suid Afrikaanse Sintetiese Olie Beperk. Rousseau, SASOL's first employee, was appointed managing director, a position he held for 18 years.

Sasolburg

Originally abbreviated in capitals, SASOL, in recent years changed to "lower cases" Sasol established its first synthetic fuels plant and its associated town, Sasolburg on a greenfield site in the Free State, south of Johannesburg. It started up with Lurgi coal gasifiers to generate syngas. The ARGE technology was used for the production of mainly higher boiling waxes and oils, including diesel. MW Kellogg, which had been instrumental in the development of fluidized bed catalytic cracking technology, led the construction of a 2,000 bbl/d **high temperature circulating fluidized bed F-T reactor.** This reactor, also called Synthol reactor, was used for the production of high proportions of medium octane petrol, LPG, and a range of chemicals. The facility was started in 1955: on 23 August 1955, the first synthesis reaction was obtained in the **fluidized bed Synthol reactor**, while the first of five **fixed bed ARGE reactors** was commissioned on 26 September 1955.

Despite initial setbacks, Sasol chemists and engineers managed not only to get the plant working satisfactorily and to defer part of the load of importing oil from the country, but they also managed to devote time to improve efficiency and to widen the product range. Feedstock for the manufacture of synthetic rubber, fertilizers and secondary chemicals followed. Together with Total SA and the National Iranian Oil Company, a refinery (NATREF, present capacity 86,000 bbl/d) was established in Sasolburg in 1960 and revamped in 1971. F-T product and imported petroleum are refined and cracked to produce ethylene for plastics, and pipeline gas was supplied in increasing quantities to industry and the town of Johannesburg. [65] As a matter of fact, the pipeline operations of Sasol are one of the key components in the successful operation of the low-grade coal conversion scheme, which is un-ambivalently linked to large quantities of tail gas. Today, Sasol Gas markets and distributes hydrogen-rich gas produced in Sasolburg and methane-rich gas produced by Sasol Synfuels in Secunda. Through its 1,400 km pipeline network in South Africa, it delivers pipeline gas to more than 600 customers, mainly in the industrial and commercial sectors. Sasol has a nice niche position in this, now extended to include natural gas, industry. Sasol has, in conjunction with the government of South Africa and Mozambique, formed a company in which it holds a 50% stake. Through this company and the U.S. $1.2 billion Mozambique Natural Gas Project (MNGP), Sasol supplies gas to customers in Mozambique and South Africa as of 2004. The investment includes the development of Temane and Pande gas fields, the construction of a central processing facility at Temane and the development of an 865 km cross-border pipeline between Temane and Secunda. The project includes the conversion of the Sasol Gas network, the conversion of the Sasolburg facilities to process gas as its hydrocarbon feedstock and the conversion of the Secunda facilities to process gas as a (reportedly 3%) supplementary feedstock. [66]

The Sasolburg plant conversion project, completed in 2004, features the installation of **auto-thermal gas reformers** incorporating licensed Haldor Topsøe technology. Sasol decommissioned the long-serving Lurgi coal gasifiers, the Phenosolvan plant and part of the Rectisol facilities. During the early phases after the feedstock conversion, about 39 million GJ (what is GJ?) of natural gas per year will be reformed into synthesis gas for downstream chemical production. The project necessitated unavoidable job losses at Sasolburg. Once completed, about 1,000 jobs were terminated as a result of reduced coal mining and the closure of the Sasol coal gasification operations. However, Sasolburg and the region are expected to benefit in the long term because of the more favorable investment environment the natural gas should create. Another benefit is the environmental improvements. According to Sasol, "this conversion project leads to a substantial reduction of carbon dioxide, sulfur dioxide and nitrous oxide emissions at Sasolburg. Odorous hydrogen sulfide emissions are eliminated. Solid waste is halved, water consumption has drop by as much as 30%, while synthetic fuels and chemicals production is up." [66]

Until recently (2004), the 20,000 bbl/d fuels Sasolburg facility operated 17 Lurgi coal gasifiers, processing 5 million tons per year of local coal. Since it is now converted to natural gas it is primarily designated to produce chemicals (some 7% of the production is wax), the rest being fuels. Although the Sasol Group is best known for its petrol, diesel, kerosene, liquid petroleum gas, power paraffin, illuminating paraffin, fuel oils and gas, it is also a major producer of ethylene, propylene, ammonia, phenols, sulfur, road tar, pitch, creosote, alcohols, ketones, solvent blends, alpha olefins, fertilizers, explosives and waxes, using **various distillation and separation processes**. Sasol's unique technology, which produces both fuel and chemical components from coal in a single step, provides it with a significant cost advantage in the production of petrochemical feedstock. The recovery of the high-value chemical components and placing them in high-value chemical markets is thus an ongoing priority.

The Sasolburg site, which hosts the majority of Sasol's R&D establishment, is also the center of excellence and plays another important role in reactor development. Here, in parallel with the high temperature SAS reactor development, Sasol has been working on the **low temperature slurry reactor concept or Sasol Slurry Phase Distillate (SSPD) process**, using a **cobalt on alumina catalyst**. In 1993, a 5 meter diameter, 25 meter high slurry reactor with a capacity of 2500 bbl/d was commissioned in Sasolburg. The unit is now the main producer of wax for Sasol. In this unit and their 1 meter diameter PDU reactor, Sasol perfected their (internal) catalyst wax separation. Having previous experience with even larger reactors, like their 10 meter diameter reactors for the SAS process, Sasol has taken this slurry concept to a 17,000 bbl/d capacity. This 17,000 bbl/d concept is reflected in two of the projects Sasol is constructing: Qatar and Nigeria. These plants are being developed at a total estimated combined cost of more than U.S. $2.1 billion. Sasol Technology formed an alliance with the Japanese-based IHI-Nissho Iwai consortium in April 2002 for the design, fabrication and supply of the proprietary Sasol Slurry Phase reactors to be incorporated into all GTL plants.

SAS, Synthol & SPD Reactors at Sasol Secunda

Secunda

In the late 1960s, an increasing pressure on the “apartheid” policy of the South African government resulted in international boycotts. Sasol’s response to these developments was to commission a feasibility study on the establishment of a second oil-from-coal plant in 1968. At the end of 1974, plans for the erection of Sasol Two were announced at a cost of R2458 million. A site about 100 km to the east of Johannesburg was chosen, again completely green-field and appropriately called “Secunda.” The plant began production in 1980, just before the real oil boycott of South Africa started. It comprises 40 Lurgi gasifiers and 8 **fluidized bed, high temperature F-T, Synthol reactors** to produce 60,000 bbl/d fuels. At that time, South Africa imported much of its oil from Iran and the overthrow of the Shah precipitated a further oil crisis. Therefore, already during the construction of Sasol Two the decision is made to duplicate the facility. The result was Sasol Three, which was commissioned in 1982 adjacent to Sasol Two. This facility reached full production in 1983, having at the Secunda facility (the capacity to) convert 43 million tons per year of coal to 120,000 bbl/d fuels. It is a very impressive facility, located in a safe, yet spectacular setting (see picture below).

SASOL **Within Secunda’s Safety Zone**

As one can imagine, the high velocity operation of the circulating Synthol system inevitably leads to some degree of erosion, triggering maintenance and replacement needs. In other words, it comes at a cost. Therefore, from 1989 onwards Sasol developed the **Sasol Advanced Synthol (SAS) reactor, an ebulating bed system** with internal heat exchange. The lower velocity in the SAS reactor reduces erosion, but also moderates catalyst attrition. In 1995, the first SAS reactor with a diameter of 8 meters and capacity of 11,000 bbl/d F-T products was commissioned. It was shipped across the Indian Ocean to Richards Bay and from Richards Bay the reactor was transported in by truck-tractor to Secunda. In 1999, the SAS reactor concept was taken to 10.7 meter diameter (28 meter high) and 20,000 bbl/d, thus since, the 16 Synthol reactors have been replaced with 8 SAS reactors, at a capital cost of more than R 1 billion. The reactors are operated with **a precipitated iron catalyst**, which is manufactured onsite. Sasol Synthetic Fuels (Pty) Ltd. (SSF) announced in March 2001 that work was under way for the installation of a ninth Sasol Advanced Synthol (SAS) reactor at its plant in Secunda, South Africa, based on the success of the eight SAS reactors, previously installed. Hyundai Heavy Industries built the reactor in Korea. Fluor Daniel acted as managing contractor on the project. Fully assembled on site, this reactor has an internal diameter of 8.150 meters, a height of 31.250 meters and a total weight of 692 tons. The total value of the project is R220 million ($27 million). This project was completed in 2002 as well as the R345 million Synthol light oil capacity expansion project. Sasol Synfuels 2002 projects under construction include the R280 million skeletal **isomerization plant** and the R595 million fifteenth **air-separation unit**. [66] [67] On the latter, Air Liquide has supplied the Secunda facility with 14 oxygen units at a capacity of 2,500 tons per day each. With the start-up of the 3,550 tons per day oxygen capacity 15th unit in 2003, Secunda exceeded a total capacity of 38,500 tons oxygen per day and is the single largest oxygen facility in the world.

With all the revamps, extensions and natural gas supply, to-date Secunda Synfuels produces approximately 150 000 bbl/d liquid fuels and another 15,000 bb/day–20,000 bbl/day equivalent in chemicals. It also houses an enormous utility complex. Secunda synfuels generates not less than 600 MWe, while it uses approximately 1100 MWe, which is for the Secunda Two and Three synthesis complexes as well as the mining activities. Currently Secunda uses approximately 37 million tons of air dried coal per year, with 25 million tons to the gasifiers and synthesis system, and 12 million tons to the boilers for steam and power generation.

ORYX GTL – Qatar

Sasol's flagship, and the current crown of its globalization program, is called **ORYX**. In March 2001, Sasol and Qatar Petroleum (QP) announced a JV, called ORYX-GTL Ltd, (49/51%, respectively) to construct a 34,000 bbl/d slurry phase F-T plant in Ras Laffan Industrial City, Qatar. The plant was 75% complete in March of 2005, began start-up late 2005 and was originally scheduled for production early 2006. It had an estimated cost of $650 million for the plant as part of a total investment of $900 million for the entire facility. The latter number includes gas production and gathering facilities. The Front End Engineering Design (FEED) performed by Foster Wheeler, Reading, U.K. was started in June 2001. Technip-Coflexip of Italy was selected as EPC contractor; while Auto Thermal Reforming Technology of Haldor Topsøe is being used for synthesis gas production, Air Products supplied the oxygen plants. About 340 million standard cubic feet a day of gas, supplied through the Enhanced Gas Utilization project at Ras Laffan with gas from Qatar's huge North Field in the Gulf of Arabia, will be converted. This is the first F-T project implemented in Qatar to exploit the giant North Field, off-shore Qatar. [68] The completion of the plant has been an achievement of the first order. To give some idea of how large the construction task has been, each of the Fischer-Tropsch reactors at the core of the process weighs over 2,000 tons. [69] For a view of the ORYX skyline see the two pictures below.

The Sasol-ORYX Plant in Qatar – February 2006

HH the Emir Sheikh Hamad bin Khalifa al-Thani formally inaugurated the ORYX GTL plant at Ras Laffan on June 6, 2006. With the costs of engineering and materials exploding in 2006, the world's largest GTL plant is quoted to have cost U.S. $1 billion [70]. The facility, the largest GTL plant in operation in the world now, and Qatar's first gas-to-liquids venture, will be using about 330 million cubic feet per day of lean gas from the North Field as feedstock to produce a planned 34,000 barrels per day (bbl/d) of liquids. This will comprise 24,000 bbl/d of diesel, 9,000 bbl/d of naphtha and 1,000 bbl/d of liquefied petroleum gas (LPG). The U.S. $1 billion and 34,000 bbl/d capacity make us believe that the plant costs have been taken down to $29,500 bbl/d. Admittedly, the U.S. $1bn ORYX plant has avoided cost price inflation because engineering contracts had been sealed before industry-wide cost pressures took off. What the story does not tell, however, is that the ORYX project profited from substantial infrastructure advantages, like water and electricity supply, while owners' costs are not reflected.

The first synthetic fuels shipment from the plant was intended to be made before September 2006. The destination for the first shipment was originally not disclosed, although Qater Petroleum sources were quoted to say that the targeted market in the initial stages would be Europe.[71] Finally, in December 2006 Western Europe was quoted as the market. [70] As to be expected with a facility of this size and complexity, the plant experienced start-up operational challenges, most of these limited to individual pieces of equipment. Poor luck hit during the startup and a non-F-T technology related support system failed. Our understanding is that the that tubes of the 1000 MW steam-super heater connected to both syngas generating facilities (ATR's) were damaged, resulting in a production delay. With a restart of the plant in the 4th quarter of 2006, the first product was announced to reach the market in the first quarter of 2007.[72][73] This actually happened in April 2007.[74] While expectations were high, reality put the excited fans and supporters of GTL back in their place: Sasol announced on May 22, 2007, that full production of its ORYX GTL joint venture project in Qatar has been delayed until mid-2008. The project, the largest GTL plant in the world, has been hit by a succession of teething problems, of which production of catalyst fines material from the slurry reactors is the latest. Sasol states that a number of possible causes for the fines production have been identified and plans are in place to "eliminate or remediate" these over the coming months. The installation of U.S. $50 million of additional downstream equipment as a back-up solution to increase throughput has already been initiated and this will be available for implementation towards the middle of 2008. Pat Davies, Sasol's CEO said daily production from ORYX for the year to June 2008 would be less than 7,000 barrels a day.[75]

In their regular investor briefing of July 2007,[76] Sasol was unfortunately not any more positive and confirmed the above, saying that "*a backup plan is under development. This includes additional filtration capacity to address the "symptoms" of the greater-than-expected level of fine material in the Fischer-Tropsch reactor product. It is expected that the capital impact of the "symptom treatment" will be small compared to the overall capital cost of the facility. Implementing this back-up solution is expected to take until the middle of 2008. These events are not expected to have any impact on Sasol rolling out its GTL and CTL technology. Though Sasol's intention is to achieve full capacity at ORYX as quickly and safely as possible, our experience is that starting up technically complex and first-of-kind facilities takes time and is inherently problematic.*

Over the last 50-plus years Sasol has successfully developed, implemented and operated several generations of large-scale synthetic fuel plants. Based on this experience, we are fully confident that the abovementioned challenges will be overcome. In the interim, however, a prolonged ramp-up period can be expected."

Recent good news[77] is that the levels of fines material (which had been choking the plant's filters and thus, preventing a ramp-up to full production) have been substantially reduced to nearly within the designed range and ORYX began, for the first time, operating both trains simultaneously in October 2007.

(Photo courtesy: Sasol) Overview of the ORYX plant.

The setback in the ORYX project has its repercussions on the planned expansion of the project. A planned expansion of ORYX to 100,000 b/d is on hold until the project proved it is running smoothly, and it is also going to be subject to tighter gas allocations in Qatar. "There will be gas; the question will be when that gas will be available," Mr. Davies said.

Escravos GTL - Nigeria

Another significant development is the global joint venture between Sasol and Chevron, called Sasol Chevron. This joint venture is based on the Memorandum of Understanding, signed on behalf of the two companies by Pieter Cox, managing director and chief executive officer of Sasol Limited and Richard Matzke, president of Chevron Overseas Petroleum Inc. on 9 June

1999.[78] The precursor to this joint venture, however, has been a relationship between Sasol and Chevron, established with the announcement in April of 1998 of a joint feasibility study to implement a GTL plant in Nigeria. Sasol Chevron was formed in order to take advantage of the synergies of Sasol's and Chevron's strengths in the Gas-to-Liquids field: Sasol has the world's largest experience and highly advanced technology in the Fischer-Tropsch arena; Chevron has extensive global experience with respect to natural gas utilization, product marketing and hydro-treating/cracking technology as well as access to gas reserves. The global joint venture of Sasol Chevron seeks to develop ventures worldwide to develop third part and parent gas reserves. It includes a number of strategic partners:

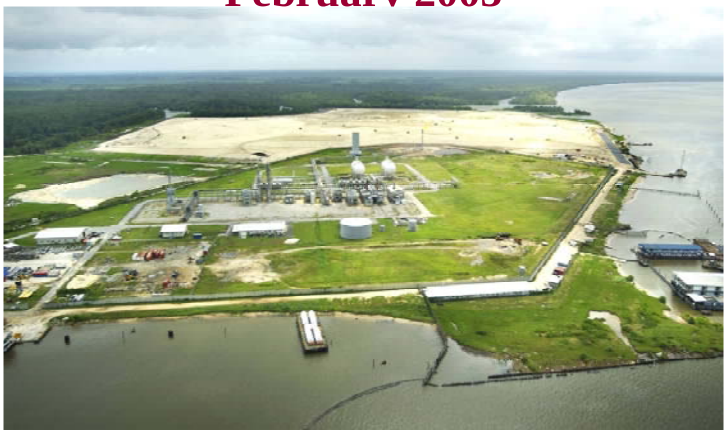
- Haldor Topsøe for the front end **Auto Thermal Reformer technology**,
- Sasol for the **slurry phase Fischer-Tropsch technology**,
- Chevron for the back end **iso-cracking technology**,
- The Washington Group as engineering contractor,
- Engelhard as **cobalt catalyst** manufacturer,
- The Japanese engineering companies Ishikawajima-Harima Industries and Nissho Iwai for the design and production of a new generation of gas-to-liquids reactors, and
- Foster Wheeler for the integration of facilities.

The aforementioned joint feasibility study to implement a GTL plant in April of 1998 between Sasol and Chevron manifested in a first joint venture plant in Escravos, Nigeria, dubbed Escravos GTL or EGTL. The plant is owned by a Joint Venture of 25% NNPC and 75% Chevron Nigeria. The FEED was completed by Foster Wheeler of Reading, U.K. in 2002. This, originally, U.S. $1.3 billion, 34,000 bbl/d slurry phase F-T plant to produce fuels was targeted to come on stream in 2003[78], then delayed to be brought into production during the 2006 financial year. Troubles in Nigeria delayed the project execution further and seriously drove up the costs. Chevron and NNPC awarded a U.S.$1.7 billion engineering, procurement and construction contract for the plant to a consortium of Halliburton's KBR, ENI's subsidiary Snamprogetti and Japan's JGC Corp in April 2005[79]. Construction, which began in July 2005, got delayed by the consortium breaking up. Since the restructuring KBR, currently being in control, maintains an optimistic schedule of the plant to come on stream in the third quarter of 2009. Signs are on the wall that this is still too optimistic. Sasol executives expect the facility to open in 2010.[80]

The EGTL two-train plant will use 17,000 bbl/d cobalt slurry-phase Fischer-Tropsch (F-T) reactors to produce 22,300 bbl/d of ultra-clean diesel and 10,800 bbl/d of naphtha, while the adjacent Escravos gas plant will process about 1,000 bbl/d of LPG produced by EGTL. "EGTL is the first of three or four proposed GTL ventures in which Sasol Chevron will take a leading role around the world," said George Couvaras, Chief Executive Officer Sasol Chevron. The facility allows for future expansion (believed up to 120,000 bbl/d) as it only used a fraction of the extensive quantity of Nigerian gas being flared at this moment. In response, Nigeria has put in place attractive tax incentives. [66] [81]

The Nigeria plant is especially challenging due to its location in a swamp, requiring large quantities of sand landfill to support heavy reactors and other equipment at the site. These conditions will unfortunately also limit opportunities to install modularized units that might be built more cheaply off-site. The developers must also deepen and maintain seabed dredging at the plant site, on the Niger River at the mouth of the Bight of Benin. The sand fill of the swamp area was completed in the summer of 2003. The two layers of sand have been placed on the EGTL project site where the process units are being constructed. Approximately 3,793,000 cubic yards of sand was placed on the EGTL project site.

Escravos GTL Plant Site
February 2005



(Photo courtesy: SasolChevron)

On the catalysis side, Sasol is known for work on both a **low temperature iron catalyst** and a **cobalt catalyst, supported on alumina oxide**. In the latter case, Engelhard became the catalyst-manufacturing partner of Sasol. In a joint venture (JV), they have built a catalyst manufacturing plant in De Meern, the Netherlands. The commissioning of the 220 million, dedicated Engelhard production facility at De Meern in the Netherlands was completed in January 2002. It has since been producing and stockpiling catalyst for the Nigerian and Qatari GTL plants. [66]

3.7.8 SHELL

The development of the Shell F-T technology started in 1974 after the first oil crisis. The realization, that the oil reserves would not last forever; stimulated development of different ways to supplement the oil reserves, required to keep the major oil companies in business. Coal was found to be the major organic hydrocarbon feedstock available, and so Shell started with the development of coal gasification. Many years of research were spent on coal gasification and synthesis of transportation fuels from coal in the Amsterdam Laboratory. By 1978, two selective Shell technologies for conversion of coal gas to gasoline and middle distillate were developed, which were further optimized by 1981. At this point it is good to point out that coal-based syngas has a prevalent H_2/CO ratio of below 1, thus making it an ideal gas for synthesis of hydrocarbons, rich in ring structures, e.g. benzene, toluene, etc. However, with environmental awareness and the increasing restrictions on benzene content in transport fuels, it became apparent that coal gasification to liquid hydrocarbons would be a difficult route. Interest focused on natural gas as gasification feedstock. A shift in the research was desirable. This came about when Dr. Ir. Jan Oelderik (Director of R&D at KSLA, met Dr. J.R. (Roland) Williams, (Coordinator Natural Gas) and a multi-year research and development program was agreed upon. The objective of Shell's Natural Gas Coordinator was to demonstrate the F-T technology as a supplement to their LNG technology and make "stranded gas" transportable. A team, consisting of leader Dr. Tiong Sie (now retired), with his principal co-workers, Dr. Ian Maxwell, Dr. Martin Post, Ir. Arend Hoek and Ir. Koos Eilers, was put to work on this task.

The team at the Shell Amsterdam Laboratory, which incorporated many more brilliant scientists, developed and patented a **(promoted) cobalt catalyst[82], impregnated on an extruded silica support.** Simultaneously to this catalyst development, other companies, including Gulf Badger, were active in this field. The latter announced in 1984 the so-called Gulf Badger F-T process. Standard Oil of California, however, in the same year bought Gulf Corporation and after restructuring changed its name to Chevron. This restructuring opened the door for Shell to acquire the Gulf Badger F-T patents and integrate the new knowledge in their technology.

On the bench scale and pilot plant level, a catalyst with a long life-time and high liquid hydrocarbon yield was developed. Further testing was done in a U.S. $10 million, 2 bbl/d pilot plant in the Amsterdam Laboratory, constructed in 1983[83]. With this pilot plant, it was also possible to produce large quantities of products, allowing industrial scale upgrading and testing, and other product development work.

In parallel to the research program, Shell's engineering office in The Hague worked on the hardware side of a F-T plant. In order to limit the technological risks, application of the proven Shell Gasification Process (SGP) and the multi-tubular reactor were adopted. Subsequently, the Basic Design (1985), the Detailed Design (1987) and the Detailed Engineering Package (1990) for a 12,500 bbl/d F-T plant were made [84]. The configuration included:

- 2400 tpd Oxygen plant
- 6 **Shell Gasification units**
- 4 **Multi-tubular F-T reactors**
- 1 **Hydro cracker/isomerization unit**
- 1 **SMR** of 150 tpd H_2
- 1 **specialty distillation** facility
- 1 wax plantOn the commercial side, Shell MDS (Malaysia) Sdn Bhd was incorporated in 1986, which in 1989 signed a Joint Venture agreement with Petronas, Mitsubishi Gas Chemical and the State of Sarawak. The latter became owner for 10%, 20% and 10% respectively. In December 1989, ground was broken in Bintulu, Malaysia on a site adjacent to the Malaysia LNG facilities [85]. In the spring of 1993, the plant entered its start-up phase and was commissioned. [86] At that point U.S. $850 million had been invested. Another significant point is the use of the largest multi-tubular reactors in the world: each > 25,000 tubes and weighing 850 tons. The plant operated very successfully in the specialty and fuels market. For example, from November 1993 to December 1997, Shell's MSD plant sold over 1 million gallons of middle distillate to four California refiners, which was blended into roughly 4 million gallons of diesel fuel and sold to on-highway fuel consumers.

The year 1997 was dramatic for the plant in Bintulu. In this particular year, the Indonesian island of Sumatra was plagued by forest fires. The neighboring environment, including Borneo and the Bintulu plant, was engulfed by smoke carried over by the wind. This exposed the plant to a design condition that had never been envisaged. As was reconstructed in hindsight, soot accumulation in the reboiler of the distillation column of the air separation unit (ASU) caused an explosion on Christmas Eve 1997.

With the ASU in the heart of the facility, the damage to the plant was extensive. The plant was reconstructed and debottlenecked (an ASU of 3200 ton per day (tpd) oxygen[87] instead of 2400 tpd and a second generation F-T catalyst was put in the reactors) so that its present rating after the restart on May 20, 2000, and further debottlenecking in 2003 was elevated to 15,000 bbl/d[88].

Shell Middle Distillate Synthesis Plant, Bintulu, Malaysia 2005 (photo courtesy of Shell)

In the last decade, Shell has been in the publicity for various projects. Common in those press citations is that future activities for Shell focus on capital cost reduction, which includes larger plant size with a nominal capacity of 70,000 bbl/d. This size of plant is considered to be Shell's "standard" design, governed by the maximum size hydro cracker unit used for the F-T product upgrading. This size of plant can obviously only be supported by large gas reserves, in the order of 5 TCF or larger. To exemplify the foregoing: In 2000, Shell was said to be willing to spend some U.S. $6 billion on at least two projects, in some combination of the following countries: Argentina, Australia, Egypt, Indonesia, Malaysia, and Trinidad-Tobago. In Argentina, Shell is scouting locations for a plant in Tierra del Fuego, where it is in discussion with a local consortium regarding the possibility for natural gas supply from offshore reservoirs to the facility. In Australia, the company is exploring sites in both the Northern Territory and Western Australia for the GTL plant. Here, Shell is exploring GTL opportunities that would complement the substantial liquefied natural gas industry as well as provide strategic diversification. In Egypt, plans have been announced for West Demiatta on the Mediterranean Coast. [89]

Besides aforementioned countries with large gas reserves, Shell's F-T interest has obviously always been focused on the largest known gas reserve in the world, the North Field in the Middle

East. As a matter of fact, Shell discovered this field in 1971 when it was estimated to contain 300 TCF of natural gas and condensates. In 2002, Qatar revised its gas reserve estimate to more than 900 TCF. It is of interest to note that the North field has a natural geological extension in the Iranian Pars field. Therefore, one could argue that the gas field is divided between and controlled by Qatar and Iran. As for Iran, it has been reported that Shell continues to make progress with National Petrochemical Company (NPC) on technical and commercial development of a 70–75,000 barrels/day gas-to-liquids project to be located at Assaluyeh, Iran. [90] Most progress has been made, however, in pursuing a plant in Qatar that will produce 140,000 bbl per day and would be integrated with an upstream development of the North Field: Shell's "Pearl" project.

Below is a comprehensive overview of the current situation with this project:

A Statement of Intent to this extent was signed by Abdulla bin Hamad Al Attiyah, Qatari Minister of Energy and Industry and QP chairman and Shell Gas and Power CEO Linda Cook on February 24, 2002.

On October 20, 2003, a Head of Agreement (HoA) for the construction of the world's largest Gas-to-Liquids plant was signed by HE Abdullah bin Hamad Al-Attiyah, Minister of Energy and Industry of Qatar and Qatar Petroleum Chairman, on behalf of QP and Sir Phillip Watts, Chairman of the Committee of Managing Directors of the Royal Dutch/Shell Group of Companies. The HoA comprises full fiscal terms for the project that will be executed under an integrated Development and Production Sharing Agreement. The project includes the development of a block within Qatar's vast North Field gas reserves, producing 1.6 billion cubic feet-per-day of condensate and gas, with Shell providing 100% of project funding.

The Front-End Engineering Design (FEED) work started in March of 2004, to lead to an investment decision by early 2006. The 140,000 bbl/d F-T plant (two trains of 70,000 bbl/d) was quoted to comprise an investment of U.S. $5 billion in the F-T facility, plus an additional U.S.$4 billion in the two upstream gas gathering platforms, the 24" pipeline, condensate removal facilities, dehydration plants, etc. It has been reported that the Northfield gas is extremely wet, suggesting that the upstream complex could produce at least 120,000 bbl/d of condensate and potentially more, i.e. the Pearl GTL project is expected to produce some 3 billion barrels of oil equivalent wellhead gas over the period of the Development and Production Sharing Agreement.

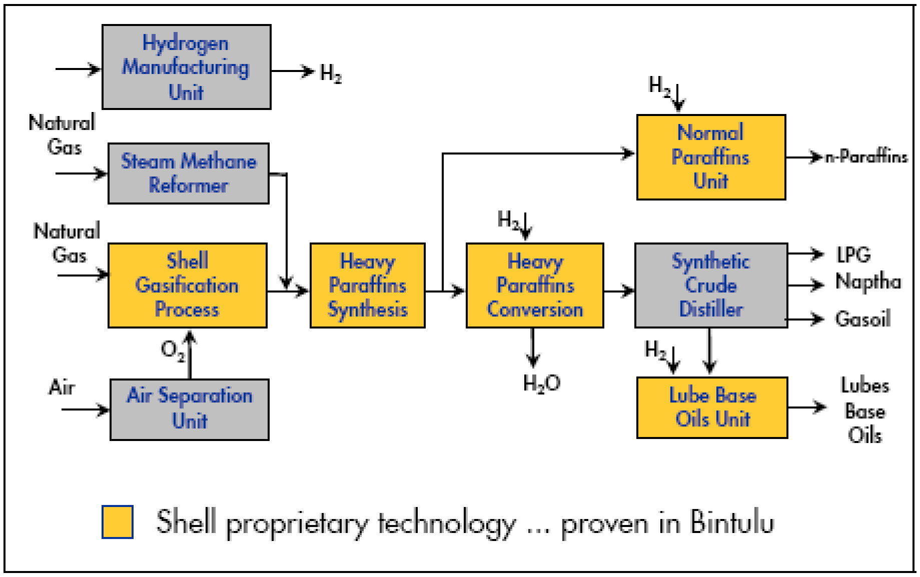
Further progress was reported at a Middle East GTL conference, [91] where the project's Technical Manager Niels Fabricius explained: "We have completed the FEED, both for offshore and onshore. We have submitted the Environmental Impact Assessment to the Supreme Council and have obtained our permit to construct. We have appointed a project management contractor (PMC), a consortium between JGC and KBR, who were also the FEED contractor. We have, at this moment, issued all EPC contracts to the market. We have already ordered some of the long lead-time items, such as the Fischer-Tropsch reactors. And we have contracted with the drilling rigs we need for the development drilling."

On August 18, 2006 the EPC contract was landed: KBR announced that it has signed a contract to provide project management and cost-reimbursable engineering, procurement and construction management (EPCM) services to Qatar Shell GTL Limited, a Royal Dutch Shell plc subsidiary, for the Pearl Gas-to-Liquids (GTL) project in Ras Laffan, Qatar. Kellogg, Brown & Root (KBR), the engineering, construction and services subsidiary of Halliburton will undertake the work in a joint venture with Japan Gasoline Corporation (JCG) of Japan, incorporating the services of M.W. Kellogg Ltd. (MWKL), a KBR subsidiary. The aforementioned underlines the pressure in the engineering market: a cost-reimbursable engineering, procurement and construction management contract versus the traditional lump contract describes the current risk aversion in the engineering and contractors' world. [92]

On February 22, 2007, a ceremony to lay the foundation stone was held in Qatar, demonstrating Shell's commitment to the Pearl project (despite the fact that ExxonMobil had stopped its Palm project two days earlier). Noteworthy to say is that, although CEO Jeroen van der Veer expressed concern about cost escalations *[the authors' comment - basically doubling the costs]*, Shell claims that with a ceiling of U.S. $18 billion and a projected product volume of 3 billion barrels, costs per barrel are on a par with modern oil exploration costs of U.S. $4–$6 per barrel.[93] One could say that in this comparison Shell is, in a sense, comparing "apples and oranges." A clean way would be to compare the value of the end product to the market. Instead, they are on one side considering oil exploration costs, including the finding, seismic and exploration capital and operating costs. Such a comparison does not take into account royalties, the oil transportation costs, refinery capital and operating costs to arrive at a finished product. On the other (GTL) side the price of the natural gas feedstock and operating costs are neglected.

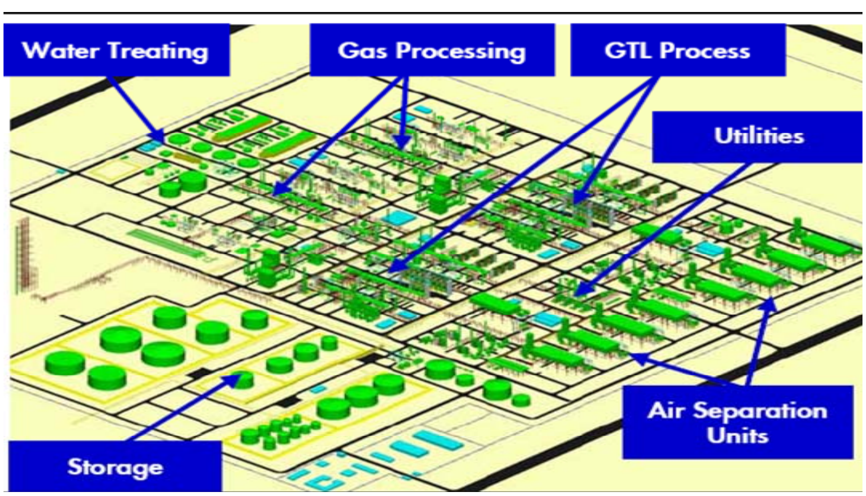
On the technical side, it was released that the project, building largely on the Shell Bintulu experience, will have two phases. The first one is to be on stream in 2009, the second two years later. Each plant will have 4 ASUs of 3,600 tons per day oxygen capacity (this should be enough oxygen for some 80,000 bbl/d per plant). The ASUs are the main consumers of power, with each of the eight units requiring a steam turbine of 78 MW to drive its air compressors. The Shell Gasification Process (SGP) will again be used, this time scaled up by a factor 4.7. Since the scale up of Pearl versus Bintulu is the same factor, the lineup per plant is expected to be 4 ASUs feeding 6 SGPs, feeding 6 multi-tubular reactors. Supplementary hydrogen will be made by means of an SMR to adjust the hydrogen content of the synthesis feed gas and to supply the single train hydro cracker. [94]

The product slate will consist of transportation fuels, n-paraffins for detergent feedstock and lube-oil precursors. According to Shell's press release, the transportation fuels are comprising naphtha, kerosene and diesel.[95] As byproducts, the plant will produce granular sulfur from the feed gas desulphurization process and, though some of it will be internally recycled, water for irrigation purposes. The figure below shows the basic process elements.



The scale of the plant is a very important factor to make the plant competitive in fuels markets. Bintulu is successful and is competitive in its own right, mainly because it produces a large proportion of unique specialty products. That recipe can't be translated to other projects though because those specialty markets are limited. As reported in 2004, Shell intended to build its next F-T plant at less than half the unit cost of the Bintulu facility. The oil price increases, however, have on the one hand eased the absolute requirement to reduce cost per barrel, as the competition fuel—oil derived diesel—became more expensive. On the other hand, the growing costs of engineering and raw materials, plus the magnitude of the orders and timeframe involved, made Shell opt for spreading out the scope over multiple vendors and, hence, multiple sourcing of equipment. The reader will understand that, with completion of the plant in 2011, up to U.S. $18 billion to spend and Shell's contract diversification strategy, the number of contracts will be numerous.

Shell Qatar GTL Plant Lay Out



3.7.9 STATOIL

Norway's Stats Olje Sellskap (Statoil) [96] is the national oil company of Norway, with headquarters in Stavanger, Norway. Statoil was formed in 1972, thus it is a young company. It was established when the new oil era started in Norway in the late sixties, when the first exploration activities in the North Sea led to substantial oil discoveries. The Norwegian government saw the need to establish a policy for how to develop this new industry and spent considerable time to evaluate various models. The result was a policy based on full government control over the resources and the award of production licenses, an independent controlling and resource management body, and a national, fully integrated oil company. However, from the first day, the Norwegian continental shelf was opened for participation of international oil companies. When Statoil was established, it was owned 100% by the government, and the company was given some preferences in the early years. However, as soon as the company was over the first years, it was treated in the same way as the international companies, without any national preferences. The company was founded as a joint stock company and all the shares were owned by the government, but it was run like a private company. The Chairman of the Board was the Minister of Oil and he also appointed the Board members. This model lasted until three years ago, when Statoil was part-privatized, and 18% of the shares were offered to private, international investors. Today, Statoil is listed on the Oslo and New York Stock Exchanges. With more than 80% of the shares owned by the Norwegian government, Statoil is still the national oil company of Norway, and the government's objective is that the Norwegian government shall always retain a majority of shares in Statoil. The step of listing Statoil on the international stock market enables the company to gain access to international finance markets and also to be in a better position to compete internationally.

Statoil's GTL research started around 1985.[97] With its large gas reserves, it is almost obvious that Statoil has been developing catalysts and process reactors for an F-T process to produce middle distillates from natural gas. The Statoil process employs a three-phase slurry type reactor in which syngas is fed to a suspension of catalyst particles in a hydrocarbon slurry, which is a product of the process itself. The process was developed in Statoil Research Centre in Trondheim, in close corporation with the Department of Industrial Chemistry, Norwegian University of Science and Technology, and SINTEF Applied Chemistry, both also located in Trondheim, Norway. Patents of Statoil involve slurry reactor design and continuous catalyst-wax separations with the use of internal filtration. [98] A promoted cobalt catalyst on alumina is used.

In 1997, Statoil formed an alliance with Sasol for the development of floating Fischer-Tropsch plants on ships or floating production systems. [99] These floating off-shore plants can be used to utilize natural gas associated with oil production. [100] A main target for Statoil has been the development of their "Snovit" field in the northern Norwegian Sea. This fell through with the earmarking of Snovit as Statoil's first LNG adventure. On September 9, 2003, Statoil signed a 20-year agreement, starting in 2006, to supply a regasification terminal at Cove Point, Maryland, in the United States with liquefied natural gas. [101]

Based on 20 years of long-term research and intensive skills development, Statoil is now approaching the commercial brink of their investments in F-T technology. [102]

In 2001, Statoil formed an alliance with the then-called Mossgas, now PetroSA, owner and operator of South Africa's gas-to-liquids facility, with the intention to build a 1,000 bbl/d slurry phase F-T unit geared to produce specialty fuels and distillates at the Mossel Bay site. This is a strategic partnership whereby the two companies will demonstrate and later commercially develop gas-to-liquids projects using Statoil's proprietary, cobalt based catalyst, Fischer-Tropsch (F-T) slurry technology. [103] The entrance into the cobalt F-T catalysis is seen by some as PetroSA's way to get around their SASOL license limitations. In June 2002, they awarded a construction contract for U.S. $73 million to Technip-Coflexip. [104] (On their website [101] Statoil talks about their U.S $50 million semi-commercial GTL demonstration plant.)

Reactor transport and installation. (Source [106])

In 2004, Lurgi AG joined the cooperation. Meanwhile (see below), Mossgas had become PetroSA and the interests in the joint venture became PetroSA 37.5%, Statoil 37.5% and Lurgi 25%. The plant was mechanically completed in March of 2004. Feedstock was taken into the facility on April 19, 2004. [105]

PetroSA-Statoil-Lurgi demonstration GTL plant (Photo courtesy Statoil)

In May 2004, when synthetic oil and wax production began, the plant's output was reportedly at 50% of capacity. The first run, however, only lasted five days. Although no apparent reasons were given, rumors have it that, in the startup, the catalyst, manufactured by Johnson Matthey, had pulverized, impairing the operation of the catalyst/wax separation in the cyclones. In private communications with Statoil, it was mentioned that they were planning a second short run in 2004 to test (start-up?) conditions. A longer run was planned for 2005 after short runs successfully demonstrated a possible operating window. Statoil explained this on their website [7] by the following statement: "*Although the basic slurry reactor/cobalt catalyst combination will probably dominate Fischer-Tropsch (F-T) technology for many years to come, the Statoil-PetroSA association is already improving some of the critical components, especially the catalyst and specific reactor details.*" Simultaneously, a new experimental pilot plant was started up at Statoil's research laboratory in June 2004 to complement work at the demonstration plant and test new catalysts and operational procedures. Its nominal capacity is 0.1 bbl/d. Therefore, we are looking at a factor 10,000 scale up for the demo plant.

The picture by Stein Brendryen, courtesy of Statoil, shows a better view of the slurry bubble column, with a diameter of 2.7 meter (9 ft) and 27 meters (90 ft) tall. [106]

The reactor was fabricated by IHI (Ishikawajima-Harma Heavy Industries, Japan.

PetroSA-Statoil-Lurgi demonstration GTL plant (Photo courtesy Statoil)

3.7.10 SYNTROLEUM CORP.

Kenneth Agee, ex Texaco research scientist, founded Syntroleum Corp., with headquarters in Tulsa, Oklahoma, USA, in 1984. While Agee runs the technology side of Syntroleum, his brother Mark, became the President and COO, and took control of the business aspect and salesmanship from the beginning. Both Agee brothers have done a splendid job in publicity for Syntroleum. They recorded as licensees (it is believed for a fee of U.S.$1 million–$2 million each), in alphabetical order ARCO(1997), ENRON (1998), Invest Australia (2000), Ivanhoe (1999), Kerr McGee (1998), Marathon (1997), Repsol-YFP (1997) and Texaco (1996). The early agreements are reported as non-exclusive "Master" license agreements, the later ones as regional non-exclusive license agreements. Syntroleum became a publicly held company in August 1998 when it merged with publicly traded SLH Corp., resulting in public offering of stock on the NASDAQ as SYNM.

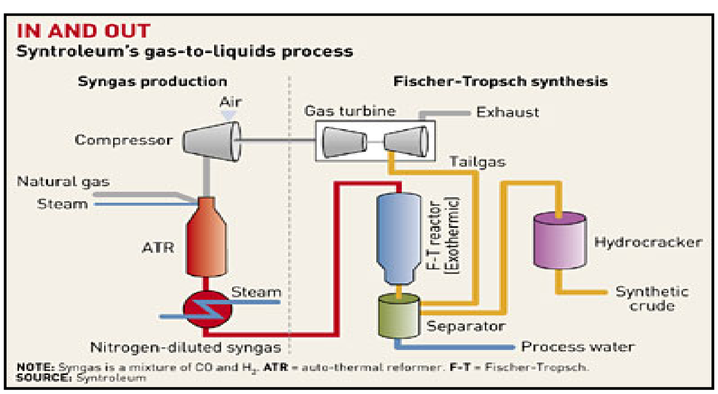
A high visibility commitment has puts Syntroleum Corp. in the public focus since 2000: They sponsored a website, which, through the work of Prof. Anthony Stranges of Texas A&M, gives the general public access to thousands of pages of historical research on F-T technology. The site, http://www.fischer-tropsch.org[107], already contains much of prior documentation on F-T technology, e.g. old U.S. and British Intelligence documents from the Second World War that have been converted. The hope is that it will become the world's most comprehensive body on historical F-T synthesis knowledge. Syntroleum will also allow third parties to submit prior art for inclusion in the database.

Apart from the fact that the **Syntroleum cobalt catalyst** based technology became the first one available on the market, the "selling point" for Syntroleum's technology has been the use of air blown syngas generation, using existing Auto Thermal Reactor (ATR) technology. The "selling points" often made include:

- Syngas generation in the ATR, more compact than a steam methane reformer
- The avoided costs of using oxygen manufacturing facilities [109]
- It is safer to operate than competing technologies

Without judgment, it seems that a cost and utilities comparison needs to be made on an individual case by case basis to (dis)prove the selling points. Admittedly, although the ATR—itself—is more compact than the SMR, the peripheral steam generating and heat recovery systems take up much of the real estate. Equally well, air separation units are most expensive for the smaller scale sizes. However, one should not forget that once the nitrogen from the air is introduced in the F-T system, it keeps being part of the size determination of equipment and piping of the ATR and F-T section of the plant. Finally, the nitrogen needs to leave the system with the F-T tail gas, producing a low Btu fuel gas.

Syntroleum's technology uses fixed or ebulating bed F-T reactors with a supported cobalt catalyst. Because of the nitrogen diluents, which help in the heat management of the F-T reaction, Syntroleum's air-based process lineup is very specific. Their approach basically uses reactor operation in "once-through" operation and limited conversion per pass. It allows for no or very limited recycle over the F-T reactor, resulting in lower efficiency to liquid products. This can be partially circumvented by placing reactors in series. The remaining low Btu (<100 Btu/scf) tail gas is disposed of by combustion in a gas turbine, providing the power for air compression and electricity generation. This normally requires spiking of this gas with the high Btu feed gas for combustion in a gas turbine, since those, even though they are run with lean fuel for low NOx emissions, require a minimum Btu content of their fuel gas, higher than the Syntroleum tail gas.



Courtesy: Syntroleum

Syntroleum's main office and laboratory facilities are located in Tulsa, Oklahoma. Here they have a single tube 2-bbl/d pilot plant, where since 1990 the demonstration of their catalyst performance and further process development has taken place. For this reason, another unspecified reactor was added in 1996. While Syntroleum's technology uses fixed or ebulating bed F-T reactors with a supported cobalt catalyst, later claims from Syntroleum also introduce the "chain-limiting" catalyst. This catalyst is intended for application in **fixed-bed, fluid-bed, hybrid multi-phase (HMX) reactors and the horizontal fixed-bed reactor,** said to be ultimately suitable for applications on Floating Platform Storage and Off-take (FPSO) facilities. [110] The "chain-limiting" catalyst has received attention elsewhere. [111] [112] [113]

In the same Tulsa facility, Syntroleum developed their **mild hydro-cracking technology**. Syntroleum will make its hydro-cracking technology available to its licensees as an additional option and will offer a "very competitive" licensing fee. [114] The process uses a catalyst system provided by Criterion Catalysts. Syntroleum plans to make additional back-end processes available to its customers. Its long-term goal is to be able to offer a full complement of fuel refining technologies to licensees. Part of that strategy was followed by obtaining from Lyondell Petrochemical Company the right to license and sub-lease a synthetic wax isomerization process based on Lyondell's catalytic dewaxing process. Since Criterion also played a part in the development of the latter process, it shall surprise no one that there is an alliance between Criterion and Syntroleum. Under this alliance, Criterion will manufacture and supply Syntroleum proprietary catalyst, which is **cobalt-based on an alumina carrier**.

In 1997, Syntroleum and Enron announced final agreement to build an 8,000-bbl/day GTL plant in Sweetwater County, Wyoming, USA. After $3 million (Enron) dollars, which paid for a detailed engineering study by Bateman Engineering, the (a.o. gas price related) economics turned out to be unfavorable and the project never came to fruition. However, the name "Sweetwater" became an acronym for the first Syntroleum project, hence, its Australia ventures (see below) were also referred to as "Sweetwater."

In 1998, ARCO exercised their license and constructed a U.S. $15 million, 70 bbl/d demonstration plant in their Cherry Point Refinery in the state of Washington (USA). The project, featuring an ebulating bed (Syntroleum calls it "moving bed") F-T reactor, started up on 7/28/1999, ran for 4,500 hours (the environmental permit was only issued for a year operation) and was terminated when ARCO was taken over by BP. After the shutdown of the unit, that plant was dismantled, transported to Syntroleum's facilities in Tulsa, OK.

ARCO Pilot Plant – Cherry Point (WA) (photo courtesy ARCO)

The same “ARCO” facilities became in 2002 the backbone of Syntroleum’s contribution in a DOE program, to produce sufficient quantities of F-T diesel for real life vehicle testing. The U.S. Department of Energy (DOE), Marathon and Syntroleum funded the design, construction and operation of the Catoosa GTL Demonstration Facility to produce approximately 70 barrels per day of ultra-clean transportation fuels. The project costs are approximately U.S. $60 million. The Catoosa GTL Demonstration Facility is Syntroleum’s first green-field demonstration of the entire three steps Syntroleum® Process from syngas production, through Fischer-Tropsch synthesis, and Synfining™ for finished product production. It contains all of the components required for a commercial scale plant.

Syntroleum and Marathon announced the first shipment from the Catoosa GTL plant on March 12, 2004. [115] The synthetic fuels will be delivered for use in long-term vehicle demonstrations by the Washington Area Mass Transit Authority (WAMTA) in Washington, DC, and by Denali National Park Services in Alaska and other university and automobile testing facilities. This initial production run is fully dedicated to the DOE’s Ultra-Clean Fuels Program, administered by the National Energy Technology Lab (NETL). The NETL is focused on pioneering a new generation of ultra-clean transportation fuels to significantly reduce tailpipe emissions from cars, trucks and other heavy vehicles. Motivated by the DOE’s Ultra-Clean Fuels program, the net benefit anticipated from ultra-clean fuels is a cost-effective, fuel savings solution for realizing environmental improvements. Integrated Concepts & Research Corporation (ICRC) managed the testing programs for NETL.

(Photo courtesy Syntroleum)

It was Syntroleum's expectation, once the DOE program was completed, to operate the Catoosa GTL Demonstration Facility to support additional fuel testing programs (including for the U.S. Department of Defense and the U.S. Department of Transportation), demonstrate GTL process technology and catalyst enhancements, and to provide training for Syntroleum licensees who are developing commercial projects.

The operation of the Catoosa facility has also lead to further technology improvements: In 2005, as a direct result of work at its Catoosa Demonstration Facility (CDF), Syntroleum was able to increase its single train capacity from 12,000 barrels per day to 17,000 barrels of ultra clean products per day. Experience obtained at the plant indicates the company can achieve a rate of up to 25,000 barrels per day of GTL products in a single train. [116]

On September 7, 2006, Syntroleum announced that it had completed the production of 100,000 gallons of ultra-clean aviation fuel for the military at the 70 barrel per day CDF. This came in combination with the longest run of its catalyst testing activity at the company's 2 barrel per day pilot plant. As a result, not only the CDF operations, but also operations at the pilot plant, were announced to be suspended beginning in October 2006 and the plants to be mothballed. [117] Quite a number of Syntroleum employees were made redundant in the latter part of 2006.

In an aftermath around the CDF, Marathon's involvement with Syntroleum changed, showing Marathon's loss of interest in GTL, the CDF and its in-route in coal to liquids (CTL): On 18 January 2007, Syntroleum announced the execution of a new, definitive license agreement with Marathon Oil Company. [118] The new agreement replaces the original Master Preferred License Agreement for Syntroleum's Gas-to-Liquids technology, and it establishes a limited master license for Syntroleum's CTL technology. This agreement allows Marathon Oil Company the non-exclusive right to use Syntroleum's Fischer-Tropsch process to produce synthetic crude. Revenue to Syntroleum under this agreement would be in the form of royalties based upon actual production volumes from any licensed plants constructed and operated by Marathon. As part of this agreement, Marathon terminated and discharged all of its rights under two promissory notes in the amount of $21.3 million plus accumulated interest in the amount of $6.3 million, originally established in connection with the construction of the CDF. Also, Syntroleum has agreed to pay Marathon two payments of $3 million each in December of 2008 and December of 2009. In conclusion, Syntroleum is the sole owner of the CDF (again). And as for the re-utilization of the CDF, only time will tell…but indications (the cooperation agreement of Syntroleum and Sinopec Corp.) are that it might end up in China.

Syntroleum holds 127 patents worldwide. Syntroleum's initial patents, issued in 1989 and 1990, are interestingly enough only process and apparatus patents, only describing the use of a cobalt F-T catalyst.[119] [120] This portfolio has been expanded over the years, particularly with the operating experience made at ARCO's Cherry Pointy facility. Syntroleum's CEO Holms explains: "We've spent over $200 million developing our technology. The F-T (Fischer Tropsch) catalyst is the real secret to this business. Syntroleum's catalyst formulation is so secret that it is not patented. The catalyst 'is our deepest, most closely held secret,'" the Syntroleum chief said. [121]

Syntroleum's technology is presently available on the market against a license fee and royalty for transportation fuels only. The use of their technology for specialties is limited to Syntroleum's own involvement. Patent licensing rates for a full IP license on F-T process and products were published by Syntroleum several years ago.[122] Royalty rates of \$0.5/barrel–1.00/barrel for the first 7–8 years of commercial production are common.

As a final remark, we need to express our concern about Syntroleum's stability. It is sad to see an F-T player have all the good intentions, try and try again, and never really make it. It underlines how difficult it is for a small company to maintain a presence in the field of oil giants. Particularly on the financial side, the smaller players are obviously disadvantaged. The most recent frequent management changes, the lay-off of personnel, the mothballing of their pilot plant facilities and the hammering of Jack Holmes, CEO of Syntroleum. "We have made demonstrable progress…that will ultimately lead to improved financial performance of the company [123]," create a worrisome picture of the company. Its ability to only bank on their upgrading technology in animal fat upgrading ventures with ConocoPhillips and Tyson Foods Inc. [124] only reinforces this impression.

The crown on Syntroleum's "extreme make-over" of 2006-2007 was placed in November 2007, when it was announced senior-level management changes and job cuts, citing a plan to improve its performance. [125] Both founder Ken Agee and CEO Jack Holmes would retire by end 2007. In the process, the company, which since its founding in 1984 never made a profit, has eliminated more than 100 jobs since 2006 and is down to 22 employees. Edward G. Roth, who previously served as Syntroleum's chief operating officer, will replace Holmes as CEO. The company's board members elected director Robert B. Rosene as chairman.

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4 U.S. Oil and Gas Overview (and Perspective)

4.1 Summary/Conclusions

The relationship between natural gas and crude oil is discussed, leading to the conclusion that, while there is a lack of about 3 million barrels per day refining capacity, there is no incentive for U.S. refiners to build additional capacity of refineries. Refiners simply pass through the ever increasing costs of feedstock/crude oil and now enjoy a comfortable refinery margin, which is currently up to $25/bbl. At the same time gasoline prices are seen to be kept low due to the dumping of surplus gasoline imported from Europe, where the demand for diesel is so much higher. This explains why diesel fuel at the pump is currently so much higher than gasoline.

With the current price increase of crude oil, driven partly by speculation, the majority of oil based commodities have been switched over to gas. Yet, the U.S. supply and demand for natural gas suggests that there is still ample volume available, leading to 1) a decline/stop in U.S. Liquefied Natural Gas imports as other nations are willing to pay more for the LNG, and 2) loss of the traditional parity in the U.S.A. between crude oil and natural gas.

As a result it is concluded that, whatever volume of natural gas is imported in the Lower 48 states of the U.S.A., the dependency of imported crude oil and/finished product will not be eliminated. Also, due to this disparity, comparison of the current natural gas market prices with the California ultra low sulfur diesel price shows that, on an energy equivalent basis, there is much greater return for Alaska from a GTL option compared with selling natural gas. Should the energy equivalent parity between crude oil and natural gas be re-established, a gas price increase of some 250 % would be needed, something, which is considered not likely.

While the relationship between natural gas and crude oil has changed over the past few years, the economic relationship between motor gasoline and diesel has eclipsed that of crude oil and natural gas. The U.S. requirement for ultra low sulfur diesel and the very large demands for diesel in Europe have added 40¢ to 80¢ per gallon to the value of diesel in comparison to that of gasoline. Today in the U.S., it is common for motorists to pay for diesel a 50¢-70¢ per gallon premium over gasoline – at least $29/bbl more than the historical relationship between gasoline and diesel. With Europe and the rest of the world using diesel because of its 25% to 30% better mileage performance we do not see this premium changing until more diesel fuel can be manufactured.

We believe that the current relationship between gasoline and diesel will remain, providing a long-term $20/bbl or greater premium for F-T diesel than historic numbers would show. Couple this with the break in energy price parity between crude oil and natural gas and F-T diesel from a GTL or CTL (Coal-to-Liquids) plant could net back even more value than through exporting the natural gas.

4.2 Relationship Between Natural Gas and Crude Oil

In this section we discuss whether there is a relationship between natural gas and crude oil in the U.S. energy market?

Virtually anyone we talk to has a different opinion on the volumes of natural gas, crude oil and refined transportation products produced, consumed or imported in the U.S. For the purposes of this report, we use information gathered from two sources.

U.S. Energy Information Administration (www.eia.doe.gov/); and

The BP Statistical Review of World Energy June 2007 (www.bp.com/productlanding.do).

This latter document is an excellent summary of world energy and BP should be commended for providing this public service update each year.

If we look at the six month period from August 2007 through January 2008 (the latest EIA numbers) we see that the U.S. on average produced slightly more than 5 million barrels per day of oil, with approximately 688,000 barrels per day of crude oil coming from Alaska (note: the EIA data does not include Natural Gas Liquids in the crude oil). During the same time period the U.S imported over 10 million barrels per day of crude oil and another 3 million barrels per day of refined products. The significance of the latter number is that even if the U.S. found another domestic source of crude oil, the nation lacks over 3 million barrels per day of refining capacity to meet current U.S. transportation fuel demands. While U.S. refiners have been adding capacity to existing refineries with process efficiency upgrades, no new refinery has been built in the U.S. since the 1970's. This could possibly be one of the reasons why refinery margins have crept up from the $5 to $6/bbl range in 2000 to over $20/bbl in 2006. A North Slope GTL plant represents new refining capacity for the U.S. and a potential threat to these higher margins, especially on the U.S. West Coast. The U.S. currently (2008) imports roughly 75% of its crude oil/transportation needs. With approximately 13 million bbl/d of transportation fuel demand almost 29% of this demand (approximately 3.5 million barrels per day) is imported in the form of finished products. On an energy content equivalent scale this represents more than 17 bcf/d of natural gas being imported just to meet the U.S. refinery shortfall, as an illustration. This is approximately four times the volume of gas to be delivered through a natural gas pipeline.

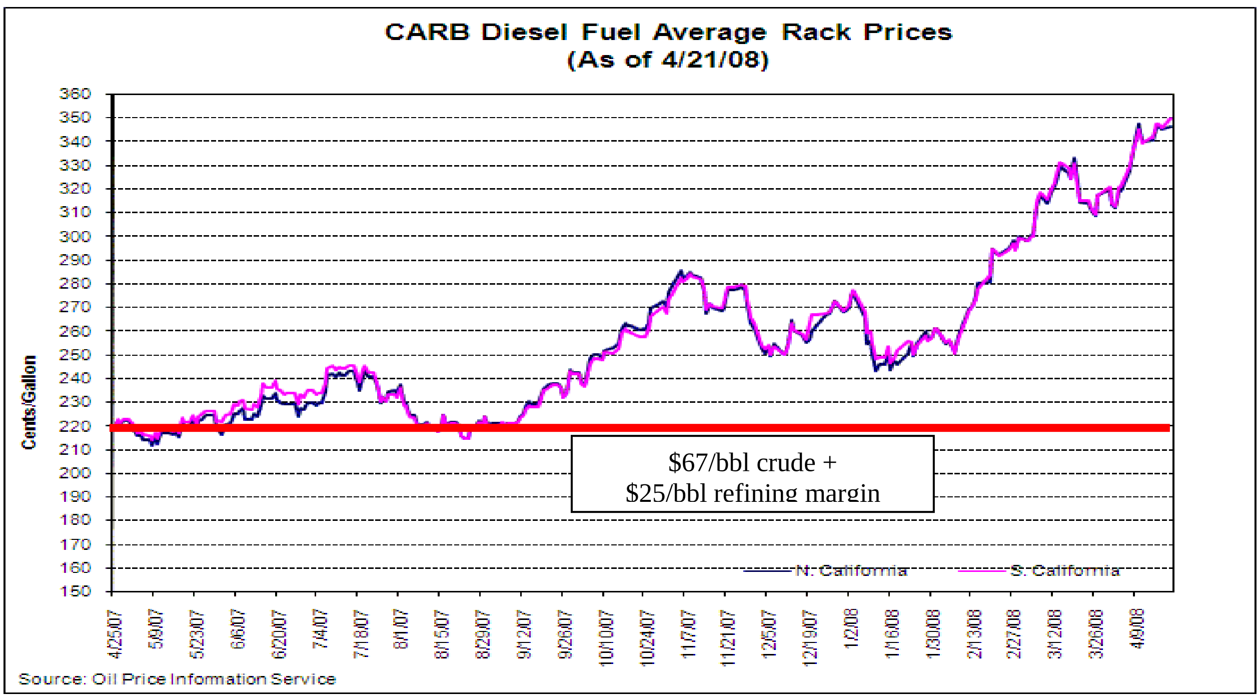
There are other indications that, since there is so much demand in Europe for diesel, that the European refiners have a surplus in gasoline, hence the gasoline price has fallen below the price of diesel because the Europeans are dumping their excess gasoline on the US market. In other words, the gasoline price in the U.S. could be even higher than it is now.

During this same time period the U.S. was producing approximately 64 billion to 65 billion cubic feet per day bcf/d) of natural gas, importing approximately 9 to 10 bcf/d of natural gas, primarily from Canada. Of this, approximately 1.6 to 1.8 bcf/d of the total U.S. natural gas is being imported as LNG. Thus 14.7% of U.S. natural gas consumption is imported with LNG representing approximately 2.4% of U.S. natural gas needs.

Historically natural gas HAS sold on average at the wellhead at a Btu equivalent less than crude oil. From 2002 to 2007, natural gas averaged 68% of the WTI price of crude oil. Some will point out that the NYMEX price for natural gas is much higher than this. This is true, but all gas is not physically located at the Henry Hub, the location of the NYMEX pricing point. Virtually all gas is sold at a number above or below the NYMEX number depending upon its location relative to the Henry Hub, its quality and the pipeline it is transported in. The EIA numbers used here are wellhead prices actually received. As more and more gas contracts are written based on the NYMEX price these average numbers may rise but even in April 2008, the NYMEX closing price for May 2008 deliveries of natural gas was $10.60/mcf or, on an energy content basis, a crude oil equivalent price of $63.60, some 54% below the current crude price of $115/bbl.

We believe that there was a fundamental severing in the price of natural gas compared to crude oil once oil hit the $60 to $70/bbl range. All of the energy consumers who could have switched off crude-based products have done so but the gas industry is still able to meet demand. In fact, LNG is not currently being imported into the U.S. because markets elsewhere in the world, especially those linked to the price of crude oil, are paying much higher prices.

If one compares a California ultra-low sulfur diesel price with an equivalent natural gas price one quickly sees a potentially greater return for Alaska than selling natural gas. Taking the April 2008 California CARB diesel wholesale price of $3.30/gallon ($138.60/bbl) plus the tax



advantage of selling a natural gas based fuel in the transportation market of $13.02/bbl, one has a market gas equivalent price of $25/mcf. Compare this to the April NYMEX number and one can see that the gas price would have to increase by 250% to equal that of diesel.

We point these facts out to show that the greatest need in the U.S. is not natural gas; it is replacing crude oil imports and more importantly adding domestic refining capacity. U.S. natural gas is not priced on a world crude oil equivalent as it is in many other parts of the world. U.S. transportation fuels are, however, priced based upon the world price of oil plus some in areas, such as the U.S. West Coast, where fuel is priced at a premium due to higher quality requirements.

4.3 Crude Oil in Perspective

The table below provides the EIA's summary of US crude oil production for the months of August 2007 through January 2008. All volumes are shown in thousands of barrels per month.

U.S. Crude Oil Supply & Disposition

Monthly Supply Thousand bbls

Process	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07	Jan-08
Supply						
Field Production (Commercial)	154,266	146,970	156,188	150,178	157,219	157,893
Alaskan	18,797	19,179	21,642	22,188	22,773	22,027
Lower 48 States	135,469	127,792	134,546	127,990	134,446	135,867
Imports	318,808	309,442	303,052	299,338	304,500	310,010
Commercial	318,808	309,442	302,001	298,783	304,500	310,010

Average daily volume 5,014,750 bbl/d with approximately 688,000 bbl/d from Alaska

Different reporting groups sometimes include Natural Gas Liquids (NGLs) in the oil numbers raising the numbers above by 1 to 1.5 million barrels per day. For this report we will stick with the EIA-reported numbers.

Current proven world oil reserves are in the range of 1.2 trillion barrels with current world consumption approximately 83.5 million barrels per day providing a reserve to production ratio slightly over 40 years. China is projected to overtake the U.S as the number one oil consumer by the end of this decade with India also leading a surge in oil consumption, both fueled by the world demand for their products and services. It has been said that if half of China's population were to use 1 gallon more fuel per day, China would need an additional 15 million barrels per day of oil. This is unsustainable with current known oil reserves. While the existing world's oil producers can meet current demands, the high price of crude oil is a factor of three major issues:

- Financial trading of crude oil futures;
- OPEC's desire to keep the world price as high as possible and
- The weak U.S. dollar.

Global consumption is barely growing, the lowest since 2001 and at half of the recent 10 year average, according to BP's review. In our view there is nothing to prevent the world price of crude from dropping to $60/bbl except the desire of the OPEC Oil Producers. With 75% of the U.S. crude oi and transportation products imported, our nation's fate is in the hands of OPEC for the time being.

4.4 Natural Gas in Perspective

The chart below provides the EIA's summary of US natural gas production and consumption for the months of August 2007 through January 2008. *All volumes are shown in billions of cubic feet per month.*

Natural Gas	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07	Jan-08
Gross Withdrawals	2,059	2,006	2,107	2,094	2,197	2,181
Marketed Production (Wet)	1,716	1,668	1,731	1,714	1,790	1,769
Extraction Loss	73	72	77	76	77	75
Dry Production	1,643	1,596	1,654	1,638	1,713	1,695
Supplemental Gaseous Fuels	5	5	4	5	4	2
Net Imports	364	296	283	258	300	303
Net Storage Withdrawals	-126	-298	-258	108	569	824
Balancing Item	46	-11	-51	-183	-192	-210
Consumption	1,933	1,588	1,633	1,826	2,393	2,613

U.S. gross natural gas production averaged 68.7 bcf/d while consumption was 65 bcf/d

Net imports were 9.8 bcf/d of which approximately 1.7bcf/d was LNG

Unlike crude oil demand, U.S gas production can meet 85% of domestic demand with Lower 48 gas production. When we understand that the majority of the natural gas imported into the U.S comes from Canada via dedicated gas pipelines (which really have no other outlet) we realize that the U.S only truly imports 2.4% of its natural gas needs from overseas. It is unlikely that this 2.4% import requirement can or would influence the price of the remaining 97.6% of natural gas production. In fact, with the recent rise in crude oil, LNG, which is in general priced outside the U.S. market on a crude oil equivalent basis, is not being imported to the U.S.

The importance of natural gas as a source of energy in the U.S. has increased substantially in recent years and is only expected to continue. This demand is based partially on the fact coal burning produces higher emissions of Green –House Gases (GHG) but interestingly while the U.S. does measure $CO_{2,}$ methane emissions from burning natural gas in a vehicle or gas-fired electric power plant are not measured. Methane is some 30 times worse as a GHG emission than CO_2. It could well be that if the U.S. adopts the European standard for methane measurement natural gas will not be as attractive as a transportation fuel or possible a power generation replacement for coal.

Another very important point to consider is that as the price of natural gas continues to escalate compared to coal, electricity produced from natural gas will become increasingly more expensive. At some point the U.S. consumer will say enough. The power of consumer conservation measures to influence the market is underestimated, in our option. When we consider that there are approximately 300 million electrical consumers in the U.S. and if only one third decided to conserve 200 watts of power per day (two 100 watt light bulbs or a computer not running for half a day), they could cut gas consumption from electric generation by 4 billion cubic feet per day. That is the equivalent of the Alaska Gas Line throughput – turned off in a flick of the switch. Many pundits say this could not happen but one only has to look at the debacle in the California Energy Crisis. Shortly after the Governor of California told its citizens that their electric rates were going to dramatically increase, Californians turned down the power and the electric crisis was over. With the U.S. having one of the highest energy consumptions per capita, a little conservation spread across the entire U.S. can have a major impact on natural gas consumption. A 200 watt electric savings spread across 1/6 of the U.S. could wipe out the need to import LNG except for peak shaving needs.

Conservation of motor fuel use will be more difficult. The U.S. driver would have to save or reduce by 25% current consumption to eliminate imports of finished transportation fuels. While a step in the right direction, it would have no impact on crude oil imports.

4.5 Historical Relationship Between Gasoline and Diesel

Throughout the last 40 years, diesel fuel was usually sold at the same price as regular gasoline or at a slight discount to gasoline. American refiners in general produced the maximum amount of gasoline at their refineries with approximately 20% of refinery output middle distillate fuels such as road diesel. In the 1960's through the 1990's U.S. refiners could meet domestic demands for gasoline except during the peak summer driving months. In general gasoline prices rose 15¢ to 25¢ during the summer. The price of diesel rose in sympathy but general there were no shortages of diesel fuels. Throughout this period the refiners were importing gasoline, usually from Europe to meet these seasonal shortfalls. European refiners operated just the opposite of U.S refiners. They produced the maximum amount of diesel, the preferred motor fuel, and minimized gasoline production. Even so, European refiners produced more gasoline than local demand required, so they exported the excess, usually to the U.S.

By the 2000's, U.S. demand for motor fuels had outstripped U.S refinery capacity almost 365 days a year. Thus the U.S. was importing gasoline year round to meet driving demands. This allowed the refinery market to place premiums on gasoline year round, not just the "summer" or peak driving seasons. Again diesel prices at the pump usually increased in sympathy. Around 2004, U.S. refiners could no longer meet diesel demand and began importing diesel to the U.S. Thus for the first time in U.S history demand outstripped domestic supply for road diesel. In 2007, the U.S. required on-road diesel to contain less than 15 ppm of sulfur, referred to as ultra low sulfur (ULS) diesel. Production of such ULS requires higher degree of desulfurization in the refinery hydro-desulfurizers to reduce sulfur levels. This required the U.S. refining industry to spend capital. Alternatively some refiners reduced diesel throughput in existing units to allow for higher levels of operation. In both cases the increase in capital per gallon of diesel processed needed to be recovered so the price of diesel had to increase. Many refiners claimed during the hearing on the cost of implementing these new lower sulfur requirements that the pump price would increase 5¢/gallon to 15¢/gallon until the capital costs were recovered.

In 2007, we find that road diesel prices have increased 50¢ per gallon to 80¢ per gallon above the historical relationship between regular gasoline and diesel. Recovering the capital cost of ULS diesel does not explain the price increase of diesel. Although there is not a clear consensus on this point, many feel that the demand for road diesel in Europe, coupled with the increase in diesel needs in China and India, have placed a worldwide premium on diesel. As crude oil prices rise causing the pump price in the U.S to exceed $3.50/gallon people are going to seek more fuel-efficient cars. Diesel cars are far more fuel efficient than gasoline cars, usually by 25% to

30% more. As more people switch to diesel, the demand across the world for diesel will continue to rise.

One should ask why would anyone switch to diesel if the cost per gallon is 50¢ per gallon higher? Even at 50¢ more, the cost to drive 600 miles in a diesel-fueled car or truck is less than cost to drive the same car with a gasoline motor. As example, we take two similar VW Beetles, one with a diesel that gets 30 mpg in town, one with a gasoline engine gets 20 mpg in town. Gas costs $3.50 per gallon and diesel $4.00 per gallon. The cost to drive 600 miles is $105 for the gasoline Beetle and $80 for the diesel Beetle, a $25 savings even though the cost of diesel is 15% higher.

Not only is there an economical incentive for the public to switch from gasoline to diesel, but proposed legislative requirements will reinforce this. On April 22, 2008 the U.S. Department of Transportation (DOT) proposed new fuel economy standards [2] that will result in a 25% increase in fuel economy by 2015. The proposed new Corporate Average Fuel Economy (CAFE) standards apply to cars and light trucks—pickups, vans, and sport utility vehicles (SUVs)—starting with vehicles in model year 2011, most of which will go on sale in late 2010. The proposed standards increase fuel economy by 4.5% per year for five years, ending with model year 2015. For passenger cars, the proposal would increase fuel economy from the current 27.5 miles per gallon (mpg) to 35.7 mpg by 2015. For light trucks, the proposal calls for increases from 23.5 mpg in 2010 to 28.6 mpg in 2015. The proposed standards are the first step in implementing a 40% increase in fuel economy by 2020, as mandated by the Energy Independence and Security Act of 2007. [3] Diesel engines can achieve these results just as they have in Europe.

We believe that the current relationship between gasoline and diesel will remain, providing F-T diesel with a $20/bbl or greater premium than historic numbers would show. Couple this with the break in energy price parity between crude oil and natural gas and F-T diesel from a GTL or CTL plant nets back even more value than exporting natural gas.

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5. THE MARKETS FOR GTL PRODUCTS

5.1 Summary/Conclusions

The market for GTL products can be split up into fuels and specialty markets. In the fuel markets GLT diesel is the most important component, followed by GLT kerosene, which enjoys an increasing popularity as jet engine fuel. Many factors will drive GTL technology introduction into the US. Market values, coupled with demand for incremental diesel and a desire for oil import independence are three of the key components that would make this happen.

Without question the market for F-T diesel in the US is unlimited. The current average wholesale price for diesel in the US will support a Sasol/Shell-type GTL plant without any government support, even with GTL CAPEX of about $40 billion for a 450,000 bbl/d plant. In comparison such costs correspond to an oil replacement cost of less than $13 per barrel, a level which already today is attained in many Gulf of Mexico project. As environmental laws drive the need for cleaner diesel, F-T diesel will sell for a premium as a blend stock. With a demonstrated sustainability of a GTL supply, municipal bus fleets and large corporation diesel truck fleets will pay a premium for F-T diesel to avoid costly compressed natural gas (CNG). The biggest hurdle for GTL program is market acceptance of the diesel engine and the unknown fuel, F-T diesel. Once demonstrated an F-T GTL program will quickly gain more and more market share, Congressional support and public awareness.

Putting the U.S. market for motor fuels in perspective, currently the U.S. consumes approximately 13 million barrels (500 million gallons) of motor fuels per day. Approximately 4 million barrels of this is middle distillate, of which 2.4 million bbl/d is on-road diesel. There is an increasingly diminishing appetite for gas-guzzling heavier (SUV) vehicles and increasing hunger for fuel efficient cars, such as diesels. With the advent of ULS diesel in the third quarter 2006, expect to see a gradual shift from gasoline to diesel as the US legislates higher CAFÉ standards for its fleets.

California already has no distinction between on-road and off-road diesel (for ultra-low sulphur) today. By 2010 all on-road and off-road (marine and train) diesel will be in the same quality category so in effect by 2010 diesel demand will be 4 million barrels or 168 million gallons per day. (This assumes no increase in demand from today). As a result a 450,000 bbl/d GTL plant on the Alaska North Slope will not make a dent in the market and enjoy continued price stability.

5.2 Fischer-Tropsch Product Markets-General

The classical phrasing around introduction of new technology in the market is: “Technology push, Market pull.” In this section on “GTL Products in the Market”, and the potential of F-T products in them, we will explore the latter “Market pull”, particularly for the products. We will first concentrate on the important product markets, then, in the second part of this section, give some details on opportunity markets. One could argue from a sales/service perspective that any market is important, however, in order for the F-T technology products to come to market it initially needs to find a platform of relative price stability. These are markets where the additional production volume of F-T products from, for example, one additional world scale plant of around 450,000 barrels per day (bbl/d) does not make a significant dent in the market price.

So, what is going to be the ultimate supply of F-T products? What is the potential volume we have to consider?

The answer to this is a number which is continuously in motion. Many in the U.S. know that we import millions of barrels per day of crude oil to meet current demand. By some estimates this number is in the 12.5 million barrels per day range. Most however are unaware that included in this is approximately 3 million barrels per day of refined products like gasoline and diesel. This means that the U.S. does not have the refining capacity to meet current transportation fuel demands. That is almost 46 billion gallons per year. Still, to many this is just a number. Converted to a natural gas equivalent number this represents almost 18 billion cubic feet per day of natural gas; 23% of January 2008 U.S. natural gas market consumption. By contrast, U.S. imports of LNG only amounted to 2.4% of U.S. consumption for the months of July 2007 through January 2008.

It is good to remember that history repeats itself: after a wave of interest in F-T in the 1990s (with activities like building the Mossgas and Bintulu plant), in a second wave in the 2003/04 period over 700,000 bbl/d Fischer-Tropsch capacity has been announced.

It is also good to remember that the aforementioned interest and entry in the market is often driven by ulterior motives. As the former Chief Technologist of Sasol Synthetic Fuels, John Marriott, once remarked (and who else can make such observation better):

"I follow the progress of GTL closely and am concerned that the need for LNG in the U.S.A will divert all the attention away from GTL. Some of the majors have used the GTL chip to get access to gas reserves for LNG. If companies get enough excuses they may not go ahead with the GTL projects in favor of the LNG ones. This is already what has happened with Conoco and I suspect others as well."

The following table[1] gives an overview of the situation in project development at the end of 2005 and adjusted for developments in February 2007, when ExxonMobil decided together with Qatar' government to cancel the ExxonMobil GTL project in favor of pursuing the development of the Barzan project in Qatar's North Field to supply domestic gas.

TABLE 1

Company	Capacity	Location	Investment	Current Status
Sasol/Chevron	34,000 bbl/d	Nigeria	$1.3 billion	Under construction
Sasol	34,000 bbl/d	Qatar	$ 1 billion	Start-up end of 2006
Shell	140,000 bbl/d	Qatar	$12 billion	Under Construction
World GTL	2,250 bbl/d	Trinidad	$100 million	Under Construction
ConocoPhillips	160,000 bbl/d	Qatar	>$6 billion	Negotiations on hold
ExxonMobil	154,000 bbl/d	Qatar	$5 billion	Cancelled Feb 2007
Marathon	140,000 bbl/d	Qatar	$5 billion	Negotiations on hold
Sasol/Chevron	170,000 bbl/d	Qatar	$5 billion	Negotiations on hold
Tinrhert	34,000 bbl/d	Algeria	???	Cancelled/on hold
Arva Asul	10,000 bbl/d	Iran	???	Study
Total	**844,250 bbl/d**		**+$30 billion**	

The above table gives rise to the following comments:

First, all of these planned projects in Qatar are taking gas from the giant (over 900 Tcf) North field. However, some readers might be familiar with the fact that there are indications that this gas field extends into the Iranian territorial waters where it is called the South Pars field. Therefore, it is not surprising that, even though with the USA/Iran embargo we hear from the Iranian side that GTL projects have been announced:

Second, it is noteworthy that the combined set of the projected plants described above are all located in the Middle East, implying a regional "pile up" of products of certain quality. Together with the current production of F-T products (in GTL: PetroSA - George, SA 32,000 bbl/d and Shell - Bintulu, Malaysia 14,700 bbl/d, in CTL: Sasol - South Africa 150,000 bbl/d,) the new projects over 400,000 bbl/d of F-T products will be coming to the market by 2015, half of which would be from Qatar. To some this might seem a glut. However, in perspective it is only slightly more than the Petromin/Shell Al Jubail refinery capacity or just a fraction of the annual crude oil demand growth.

Third, these projects encompass a multi-billion dollar total investment and are all announced to be operational in the next ten years. In consideration, one might make the following reflections:

With few of the projects already under construction, a concern about the logistics is developing. As one of our colleagues mentioned: "***Already now, when the workers of Ras Laffan go for their tea break, major traffic congestions are faced! Can you imagine the future?***" Also imagine the tons of steel, cubic yards of concrete, kilometers of cable, etc. that are required on one spot in a limited timeframe. Obviously congestion and limitations in supply highly influence competition, costs and project execution time. Hence, it led early on to the speculation that one or more of the announced projects would not make it, or that some of them would be significantly delayed. If the reader would expect one company to be able to afford, complete and operate a GTL plant it would be ExxonMobil. The "not even make it" became a reality when ExxonMobil, together with the Qatar government, decided to cancel its GTL project in February 2007. ExxonMobil decided to develop gas and condensates. The Qatar government placed a moratorium in 2005 on the development of any further gas projects beyond those expected to be completed by 2011. Officials said that the emir imposed the moratorium out of concern that the North Field, which contains 900 TCF of gas, is not as geologically homogenous as once thought. In actual fact, even before the ExxonMobil announcement, at the gas conference in Port of Spain, April 26, 2005, Abdullah bin Hamad Al Attiyah, the Qatar Energy Minister, announced[2] the delay of three more of the projects for up to three years:

- the ConocoPhillips 160,000 bbl/d project
- the SasolChevron 170,000 bbl/d project
- the Marathon 140,000 bbl/d project

Finally, the market for the products of all those projects is Europe. The production of every project is therefore driven to diesel automotive fuel.

This leads us to discuss the markets where the volume is expected to fit and where North Slope GTL products might find a home.

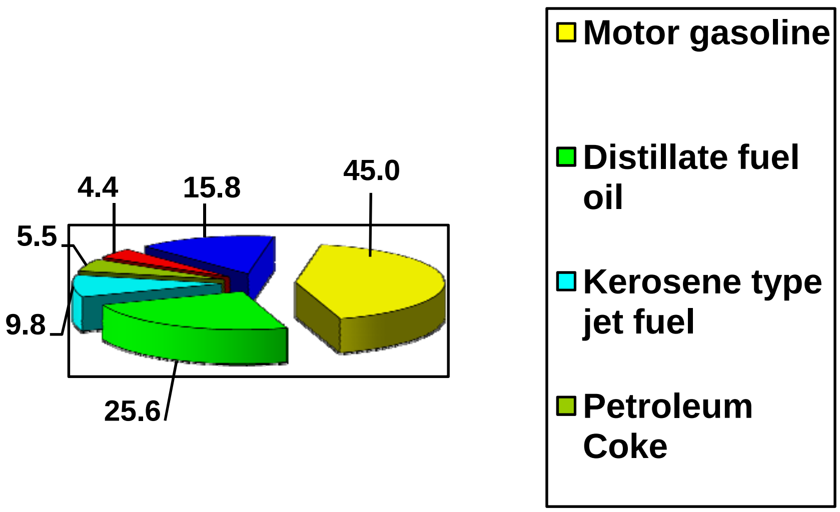
Before entering into the detail, here are some introductory remarks:

The first is that we can approach the markets for FT products very simplistically—they fall in the hydrocarbon of crude oil-based sector; they are the transportation fuels market and the specialty products market. On both of these markets, one can write a separate book. Both of these are in continuous motion and transformation, so the information presented here is the image of a "moment in time." Once upon a time, books were the ultimate source of market information. Gathering market data used to be an elaborated and time-consuming job. Anymore in this era of website use, the information is abundantly available. (We might add that such abundance of data has also taken much of the peer review out of the equation; hence, the information is not always accurate.) Websites like the U.S. Energy Information Administration (EIA) [3] and the National Association of State Energy Officials (NASEO) [4] provide (the more accurate) data as well as links to other sources.

Very simply, one can capture the aforementioned markets with the following:

- **The transportation fuels market is huge, steadily growing, inflexible and price insensitive.**
- **The specialty products market is small, growing, and more flexible and very price sensitive.**

In order to get a better grip on the size and opportunities, we need to ask: What is the market we are looking at? What really comes out of a barrel of oil?
The answer, which is different for different consumer areas/countries, is for the USA presented in volume percentages and product groups in the following graph.[5]



What comes out of a barrel of oil in the USA?
(Numbers in volume percentages of crude oil barrel)

A different perspective, with more emphasis given to sub-groups of the markets, is also illustrated in the table [5] below.

Motor Gasoline 45.0%
Distillate Fuel Oil 25.6%

- Home heating oil
- Diesel duel
- Refinery fuel
- Industrial Fuel

Kerosene-type jet-fuel 9.8%
Petroleum coke 5.5%

- Carbon electrodes
- Fuel coke
- Electric switches

Refinery furnace fuel gas 4.4%

Residual fuel oil 4.3%

- Boiler fuel
- Refinery fuel
- Bunker fuel
- Wood preservative

Liquefied Petroleum Gas 3.6%

- Petrochemical feedstock
- Space heating
- Cooking

Asphalt and road oil 3.1%

- Paving
- Roofing
- Waterproofing

Petrochemical feedstock 2.4%

- Alcohols
- Resins
- Fibers
- Medicines
- Cosmetics
- Plastics
- Detergents

Lubricants 1.1%

- Lubricant oil
- Greases
- Transmission oil
- Household oil
- Textile spindle oil

Kerosene-non jet-fuel 0.5%

- Illumination
- Space heating
- Cooking
- Tractor fuel

Specialty naphtha 0.2%

- Solvents
- Paint thinner

Aviation Gasoline 0.1%

Waxes 0.1%

- Fruits
- Vegetables
- Candy
- Chewing gum
- Candles
- Matches
- Crayons
- Pencils
- Sealing wax
- Canning wax

Miscellaneous products 0.4%

- Absorber oil
- White machinery oils
- Cutting oils
- Candy making, baking oils
- Technical oils
- Medicinal salves, ointments
- Petroleum jelly
- Acetic acid
- Sulfuric acid
- Fertilizers

With gasoline, diesel and kerosene fuel being dominant and a focus on the transportation fuel market, a glance at the world oil market, particularly on the supply side, is in order.

In September of 2004, the EIA of the U.S. Department of Energy (DOE) released a study that examined long-term supply scenarios for world petroleum. Under the most likely scenario—assuming a 2% annual growth rate for world's oil demand and the mean value for the amount of oil reserves—the study predicts that petroleum production will reach its peak in 2037.

The study is a re-release of an oil supply prognosis originally published in July 2000, prompted in part by the increasing fuel prices in the USA. The EIA stated that there had been no new information or developments that would significantly alter the year 2000 results. The study uses estimates of the world's oil resources by the U.S. Geological Survey. The EIA estimated that the world's growth in oil demand would be 1.9% through 2025. The critical event in world oil production will be when it reaches its peak. The following decline in oil production would leave some oil demand unsatisfied, likely leading to significant price increases. The date of the peak depends on the rate of demand growth and assumed reserves. Twelve scenarios were examined in the study, for different oil demand growth rate (0–3%) and different oil reserves. The potential dates for the peak oil production ranged from 2021 to 2112.

Only crude oil reserves in conventional reservoirs were analyzed in the study. Additional petroleum supply is expected from unconventional sources. Commercial production has already started from such sources as the Canadian tar sands and Venezuelan heavy oils, in addition to the F-T "syn-crude" supply, which we are considering in this report. While the EIA analysis is less alarming than some other reports, its authors noted that the results do not justify complacency about both supply- and demand-side research and development. This tells us that the timing of the announced GTL projects is well planned.

The EIA also prepares short-term energy outlook reports, which are published monthly. In the most recent September issue, the EIA revised the projected world oil demand growth for 2004 to 3.2% (from a previous prediction of 2.5%) above the 2003 demand. Strong demand from China accounts for much of the upward revision.

World oil demand reached nearly 84 million bbl/d (USA almost 21 million bbl/d) in the first quarter of 2005, setting a new high for years in a row. This sustained 1990s and 2000s' growth has paralleled the path demand followed in the 1970s. However, in between, oil had to struggle with the repercussions of the second oil price shock and subsequent recession, and world demand finished the 1980s at a level barely higher than its earlier 1979 peak. We may see a similar recession in the time to come.

In 2005, world oil demand growth was expected [7] [8] to slow down to 2.4% due to the increased oil prices. Despite persistent growth developments in non-OECD (Organization for Economic Co-operation and Development) countries for the 2006–2008 timeframe (+6.8 % for the period) global growth of the most recent EIA forecast shows only a 1.7% annual increase. Therefore, indeed, we are living in a world with perturbations.

Not long ago, oil analysts would have been looking at downward scenarios for oil prices of U.S. $25 per barrel and oil/energy-related projects were evaluated against that. Today's reality is quite different. Now analysts believe that oil will never drop below U.S. $50 per barrel. Oil prices have moved from just over U.S. $19 per barrel in 1999 (average WTI was at U.S. $19.30), to an average of close to U.S. $30 per barrel between 2000 and 2003; from more than U.S. $40 per barrel in 2004 oil prices reached nearly the level of U.S. $70/bbl in September 2005, in the fourth quarter of 2007, it threatened to go over the U.S. $100/bbl and by now we see U.S. $120/bbl. As a result of the steep price increases, the world crude oil demand dropped already in the second quarter of 2005 to 82 million bbl/d. But what is the future going to bring? We might be the supertanker, which once in motion is very hard to stop.

The increase in global oil prices has, in the USA, once again sparked the debate on the increasing importance of reducing oil consumption and the dependence on foreign oil. The USA, which consumes 25% of the world's oil production with only 5% of the world's population, imports 63% of its crude oil. This debate is sometimes mixed with views on stability of supply, the requirement for stabilization of the Middle East and the war in Iraq. Few, however, are aware of the origin of supply of the U.S. oil. Below is an overview of countries that export the most crude oil to the USA in June of 2005 and January of 2007, according to the Energy Information Administration. [9]

Another fairly unknown fact is that the U.S. lacks 3 million barrels per day of refining capacity to meet current demand for gasoline and diesel fuels, importing finished products primarily from Canada and Europe to meet this demand. Diesel amounts to 400,000 bbl/d of these imports. It goes without saying that any domestic transportation fuel will have a long term market provided the price is at or lower than the cost of the imported fuel. International oil companies that control the majority of U.S. refining capacity have no economic incentive to add domestic refining capacity and the U.S. Congress for the most part has not placed tariffs on imported fuels. In fact many would say that refiners have an economic incentive not to add refining capacity. By having a refinery capacity short fall refiners can raise the price of transportation fuels at the pump at will – in the words of Exxon's former Chairman, "We raised the price at the pump to prevent a shortage". They call this economic conservation and it results in the price at the pump increasing 25¢/gallon, 35¢/gallon and even a $1/ gallon so that people buy less (conserve) but 100% of this windfall goes to the refiners' bottom line. Thus we say US refiners have an economic incentive not to add additional refining capacity as they can earn upwards of $25 to $100 billion dollars more each year.

That said U.S. refiners in general will not be supporters of new "alternative fuel refineries" unless the U.S. Congress either legislates it or provides economic incentives.

U.S. Imports by Country of Origin (in 1,000 bbl/d)				
Country	**June 05**	**% of total**	**January 07**	**% of total**
Canada	1,696	16.1	2,470	18.1
Mexico	1,616	15.3	1,566	11.5
Saudi Arabia	1,564	14.8	1,563	11.5
Venezuela	1,292	12.2	1,195	8.8
Nigeria	896	8.5	1,136	8.3
Iraq	608	5.8	531	3.9
Angola	397	3.8	574	4.2
Algeria	292	2.8	778	5.7
Ecuador	288	2.7	272	2.0
United Kingdom	269	2.5	194	1.4
Total imported	14270		13623	
Total of top 10	**8,918**	**84**	**10,279**	**75.4**

(Note that with the above numbers and 20 million–21 million bbl/day consumption in the USA, one can calculate that the nation is far more than 60% dependent on imported oil.")

In understanding the petroleum industry [10], the growth in oil demand has been heavily biased toward the higher quality products, which require more elaborate refinery processing. Gasoline and middle distillates—diesel, jet-fuel, heating oil and kerosene—now account for roughly 2/3 of world oil demand. Each product slate has a market share at least double the share of residual fuel oil (the heavy fuel oil used for power generation and ship fuel), which has dropped from 25% to 13% in the last 20 years. The world's apparent consumption of refined petroleum products, and we will put the USA and North America in perspective, is accounted for as follows [11]:

World Apparent Consumption of Refined Petroleum Products, 2003
(Thousand Barrels per Day)

Region/Country	Motor Gasoline	Jet Fuel	Kerosene	Distillate Fuel Oil	Residual Fuel Oil	Liquefied Petroleum Gases	Other	Total Apparent Consumption
World Total	**20,410.8**	**4,517.1**	**1,710.1**	**21,583.0**	**10,196.0**	**7,766.8**	**13,610.4**	**79,794.2**
United States	8,943.9	1,577.8	54.6	3,927.09	772.1	2,205.1	2,561.9	20,033.5
North America (incl.CAN-MEX)	**10,214.8**	**1,735.4**	**51.9**	**4,748.2**	**1,349.9**	**2,981.3**	**3,105.6**	**24,198.4**
Europe	**2,974.8**	**1,019.2**	**111.1**	**6,105.2**	**2,146.9**	**1,027.9**	**2,706.0**	**16,091.1**

(Source: Energy Information Administration [12])

World Apparent Consumption of Refined Petroleum Products, 2004

(Thousand Barrels per Day)

Region/Country	Motor Gasoline	Jet Fuel	Kero-sene	Distillate Fuel Oil	Residual Fuel Oil	Liquefied Petroleum Gases	Other	Total apparent Consumption
World Total	**20,865.96**	**4,813.73**	**1,632.47**	**22,517.93**	**10,080.34**	**8,028.48**	**14,365.58**	**82,304.51**
United States	9,105.41	1,629.97	64.32	4,058.26	864.71	2,264.03	2,744.46	20,731.16
North America (incl.CAN-MEX)	**10,431.63**	**1,796.79**	**78.08**	**4,923.24**	**1,412.71**	**3,080.15**	**3,314.89**	**25,037.48**
Europe	**2,876.33**	**1,093.43**	**118.73**	**6,230.44**	**2,036.82**	**1,048.08**	**2,800.91**	**16,204.74**

(Source: Energy Information Administration [13])

The above tables for the world consumption of 2003 and 2004 show the increasing decline of residual fuel consumption. We have also added the data for Europe with the 2003 and 2004 data to underline the large difference in transportation fuel consumption between the USA and Europe: 68% of the fuel consumption in the USA is motor gasoline, 67% of the fuel consumption in Europe is distillate fuel or diesel. We discuss this later in more detail to point out the potential for F-T diesel in Europe.

This bias towards higher quality products has not been matched by any improvement in crude oil quality. Therefore, it has put enormous pressure on refiners' margins and investment needs. Additionally, specialty grades, such as low sulfur diesel, unleaded gasoline and oxygenated gasoline, have been mandated at international, national, regional, state or even city levels in response to environmental concerns.

To understand the shift in the product demand mix, it is helpful to categorize oil demand by the purpose for which the oil is used. There are four main energy-related uses: mobility or *transportation* (moving people or goods in private vehicles, buses, trucks, trains or airplanes), the two "under boiler" markets: *heat* and *power*, and *electricity generation*. The non-transportation uses are, as in the above tables, frequently grouped together with "stationary" uses. There are also *non-energy* or process uses, such as feedstock for the petrochemical industry.

Although energy demand for each end use responds in broadly the same way to the level of economic activity, there is a marked difference between the end uses in their vulnerability to fuel substitution. Both transportation and non-energy uses are relatively captive markets for oil. However, in many energy-related, stationary markets, the substitution risk became high in the early 1980s, after the first two price shocks and with the perceived threat of more to come. First coal and nuclear, and then natural gas, became economically attractive alternatives to oil. Therefore, these other fuels were able to dominate the new boiler and electricity generating markets and to displace oil from a large number of existing ones.

Hence, transportation, where gasoline, jet-fuel and diesel reign dominantly, now accounts for over half of world oil demand, up from under 40% in the early 1970s. Non-energy uses held their share of world oil demand steady over this same period, but energy-related stationary uses lost ground. Demand in the industrial sector, the mainstay for residual fuel oil, suffered most.

This sector became especially vulnerable to inter-fuel competition because of the synergy between the scale of industrial users' consumption needs and the economies of scale needed to justify capital intensive development projects like LNG or natural gas trunk lines. Contributing to the decline were environmental mandates that favored natural gas.

One can also analyze the abundant sources of data through the perspective of differences in standards of living, economic maturity and access to other fuels. Such differences are the prime reason for the variation of oil demand per capita between countries. The annual average is still less than 1 barrel per person in both China and India, but over 16 barrels in North America. These same factors also lead to wide variations in the product mix between regions. Dependence on the transportation sector, and thus the role of gasoline and distillate, is much greater in the mature industrial economies, and in the U.S. in particular. In the industrial countries' Organization for Economic Cooperation and Development, for instance, residual fuel oil demand accounts for a mere 10% of oil demand. Easy access to other fuels, a shift toward less energy intensive, service-oriented activities, and a relocation of some industrial activities to the developing economies have all been important factors in the decline. In contrast, in the developing countries, residual fuel oil's share is still more than double this level.

Finally, and not shown in the data presented here, there are the seasonal fluctuations of oil and energy use. The importance of heating oil, propane and kerosene as Northern Hemisphere heating fuels gives the world oil demand a winter peak. The average 3.5 million bbl/d swing between the highest demand quarter, the fourth, and the lowest, the second, creates a tendency for world prices—but not necessarily U.S. prices—to be strongest in the fall and weakest in the spring. Tables for the World Apparent Consumption of Refined Petroleum Products in 2003 and in 2004 are presented below.

World Apparent Consumption of Refined Petroleum Products, 2003 (Source: EIA [12])

(Thousand Barrels per Day)

Region/Country	Motor Gasoline	Jet Fuel	Kero Sene	Distillate Fuel Oil	Residual Fuel Oil	Liquefied Petroleum Gases	Other	Total Apparent Consumption
World Total	**20,410.8**	**4,517.1**	**1,710.1**	**21,583.0**	**10,196.0**	**7,766.8**	**13,610.4**	**79,794.2**
North America	**10,214.8**	**1,735.4**	**63.1**	**4,748.2**	**1,349.9**	**2,981.3**	**3,105.6**	**24,198.4**
United States	8,934.9	1,577.8	54.6	3,927.0	772.1	2,205.1	2,561.9	20,033.5
Central & South America	**1,051.4**	**191.8**	**54.3**	**1,512.1**	**801.5**	**463.3**	**1,131.4**	**5,205.8**
Western Europe	**2,974.8**	**1,019.2**	**111.1**	**6,105.2**	**2,146.9**	**1,027.9**	**2,706.0**	**16,091.1**
Eastern Europe & Former U.S.S.R.	**906.0**	**259.8**	**8.1**	**817.8**	**709.9**	**323.8**	**903.8**	**3,929.2**
Middle East	**967.2**	**198.0**	**168.4**	**1,336.6**	**1,156.8**	**635.1**	**892.0**	**5,354.0**
Africa	**621.5**	**149.0**	**109.0**	**904.9**	**453.6**	**228.8**	**266.4**	**2,733.1**
Asia & Oceania	**3,675.2**	**963.8**	**1,196.2**	**6,158.2**	**3,577.5**	**2,106.6**	**4,605.1**	**22,282.7**

World Apparent Consumption of Refined Petroleum Products, 2004

(Thousand Barrels per Day)

Region/Country	Motor Gasoline	Jet Fuel	Kero sene	Distillate Fuel Oil	Residual Fuel Oil	Liquefied Petroleum Gases	Other	Total Apparent Consump tion
World Total	**20,865.96**	**4,813.73**	**1,632.47**	**22,517.93**	**10,080.34**	**8,028.48**	**14,365.58**	**82,304.51**
North America	**10,431.63**	**1,796.79**	**78.08**	**4,923.24**	**1,412.71**	**3,080.15**	**3,314.89**	**25,037.48**
United States	9,105.41	1,629.97	64.32	4,058.26	864.71	2,264.03	2,744.46	20,731.16
Central & South America	**1,013.56**	**181.63**	**41.33**	**1,646.69**	**816.22**	**522.54**	**1,127.09**	**5,349.07**
Western Europe	**2,876.33**	**1,093.43**	**118.73**	**6,230.44**	**2,036.82**	**1,048.08**	**2,800.91**	**16,204.74**
Eastern Europe & Former U.S.S.R.	**937.86**	**279.54**	**7.92**	**854.96**	**673.52**	**324.87**	**962.13**	**4,040.80**
Middle East	**1,075.00**	**210.38**	**179.42**	**1,391.80**	**1,250.60**	**645.51**	**786.69**	**5,539.41**
Africa	**650.71**	**153.75**	**104.62**	**924.30**	**458.40**	**219.25**	**308.44**	**2,819.46**
Asia & Oceania	**3,880.87**	**1,098.21**	**1,102.37**	**6,546.50**	**3,432.07**	**2,188.08**	**5,065.44**	**23,313.54**

(Source: EIA [13])

5.3 Transportation Fuels Markets

5.3.1 Diesel

In the context of the diesel market we remind the reader, from a historic perspective, of the first commercial application of F-T diesel: In World War II time, the synfuels industry targeted the production of high octane, high-density aviation gasoline for the German air force, the Luftwaffe, lesser quality gasoline for vehicles, and diesel for heavy equipment and ships.

Whereas the gasoline from the coal hydrogenation process, one of the synthetic fuel processes used in wartime Germany, was excellent in **quality**, the diesel had a low cetane number (20–25). Hence, initially, the majority was blended away in the heavy fuel oil pool. Mixed with the high cetane (70-80) diesel from the Fischer-Tropsch process, however, a commercial diesel fuel with a cetane of around 45 could be produced. The synthetic diesel proved to have wonderful, non-smoking, combustion characteristics. With coal being the backbone of energy supply for the German war machine, this diesel fuel was particularly welcomed in the German underground coal mines. The latter environmental benefit has played and is still playing an important role in the marketing and pricing of Fischer-Tropsch diesel.

The world **market volume** for gasoil/diesel is steadily growing. The tables of World Apparent Consumption in this section provide for the 2003 data of over 21 million bbl/d. Global diesel demand is expanding faster than total oil demand, driven primarily by the road freight sector and from passenger vehicles switching from gasoline, particularly in Europe. Current global distillate fuel (diesel and gas oil) demand is around 22 million bbl/d (1.1 billion tons per annum - tpa) and is projected to grow at an average rate of around 2.7% per year through to 2015 to reach

22 million bbl/d or 1.5 billion tpa. Put this growth of almost 350,000 bbl/d in perspective of the potential output of a typical plant, being 45,000 bbl/d to 55,000 bbl/d. It shows that the world can accept the **production volume** of several F-T plants per year to merely accommodate the world demand growth.

To put this in perspective of a U.S. scenario, currently the U.S. already lacks 3 million barrels per day of refining capacity to meet the demand for gasoline, jet and diesel fuels, importing finished products primarily from Canada and Europe. Diesel amounts to 400,000 bbl/d of these imports.

The forecast for GTL capacity development shows that about 150,000 bbl/d or 6 million tpa of GTL diesel, less than 1% of total demand, could hit the market by 2015. All three of the major demand regions should develop large diesel deficits by 2015. In Europe and North America, the diesel deficits are forecasted to be 54 million tpa and 24 million tpa, respectively. [14] In Asia, the combined diesel plus gas-oil deficit could reach nearly 23 million tpa. The planned production of GTL diesel should thus readily find a market. Based on netback pricing, the most likely destination for GTL diesel produced in Qatar, Nigeria, and Algeria is Europe. The planned GTL plants in those countries would produce just more than 6 million tpa of diesel, potentially lowering Europe’s diesel deficit in 2015 by 15% to around 48 million tpa.

The deficits in the diesel market demand a more detailed analysis, particularly where it relates to F-T diesel. It is estimated that the transportation component in the diesel is little over a third of the world demand, or some 7.5 million bbl/d (370 million tons per annum) of diesel fuel, consumed by about 150 million diesel powered vehicles. Currently, the production of F-T diesel is limited. The estimated maximum production capacities for F-T-diesel include Sasol 100,000 bbl/day, Mossgas 10,000 bbl/day and Shell 6,000 bbl/day. In actual practice, however, the production is much lower as all plants rather produce specialties, which command a price-premium over diesel. Hence, in the large size of the diesel fuels industry (20 million bbl/day) F-T diesel can easily be accommodated. Even after the coming on-stream of all the announced F-T projects in Qatar, estimated to be able to produce more than 700,000 bbl/d of the high quality material, there is ample room.

In reality, the F-T diesel production plays an important role in local markets. For example, it is fueling the majority of the South African market; hence, fairly little of the material is available for export. On the other hand, it does not seem to attract the Qatari to use the indigenous material: His Excellency the Deputy Premier and Minister of Energy and Industry of Qatar, Abdullah bin Hamad al-Attiyah clearly stated that there are no plans now to use Gas-to-Liquids diesel on a massive scale in the local market[15]. Hence, the product will be exported, in this case to Europe, as diesel blending material. To take another example of the relatively small impact in the market, we can consider California's current nearest GTL supplier, the Shell-Malaysia, Bintulu plant. The plant produces an estimated 2400 barrels/day of transportation diesel fuel, which, even if its whole production was to be diesel, would only fill 1.5% of California's diesel demand.

The two important markets for F-T diesel are the USA and the European market, each of which is entirely different, not to say almost diametrically opposite in fuel requirements.

The total current U.S. diesel on-road market is around 40 billion gallons per annum. This is with a market that relies for some 75% on gasoline and 25% on diesel as transportation fuel. In Europe these proportions are completely inversed.

The reason for such difference can be found in three reasons:

- in public perception of the diesel engine;
- availability of diesel fuel; and
- taxation.

It should not surprise the reader that these reasons are inter-related. Let us discuss them individually, though, to put them into perspective of our GTL industry and the GTL diesel in particular:

Public perception of the diesel engine

In the USA, the current perception of the diesel engine is based on "mishaps" in the 1950s. The then introduced light/medium diesel engine was noisy, slow-with a lazy pull-up, smoked and stunk, all the reasons to have it condemned for the rest of the 1900s. Thus, U.S. car manufacturers did not see any market and have traditionally offered only few light/medium diesel vehicles. The oil price boom in recent years and connected raising fuel prices make diesel vehicles increasingly more attractive for U.S. customers. According to figures by Polk Automotive published by the Diesel Technology Forum, nearly 60% of consumers chose the diesel option in 2004 in the medium-duty truck market, which includes the Chevrolet Silverado, Dodge Ram, Ford F-Series and GMC Sierra trucks. The overall market share of light- and medium-duty diesels in the U.S. grew from 2.25% in 2000 to 3.37% in 2004[16] [17].

Availability of diesel fuel

Availability of diesel fuel at the stations further limits the market, although growth is seen also here. Availability of diesel fuel in early 2005 was quoted at 42% of fueling service stations in the USA, up from 30% in 2000[18].

Taxation

In Europe, on the contrary, much higher fuel prices and transportation fuel and vehicle taxation than in the USA have been the driving forces for exploitation of the higher efficient light diesel engine since the 1980s. The European tax system for vehicles and road maintenance/ conditioning is based on a base-load yearly fixed tax, in which the main drivers are the weight of the vehicle and the type of fuel used. On top of that the driver of the car is subject to a variable tax, levied though the fuel consumed. Traditionally, the variable tax is lower for diesel fuel than gasoline. Thus, while the base-load tax for a diesel car might be higher (because of a heavier engine) after a certain mileage driven there is a break at which the cost of driving a diesel vehicle is cheaper than a gasoline-powered vehicle. As a result, the diesel car population goes as high as 75% in countries like France. Diesels account for 50% of the new car market in Germany.

Where would the Alaska North Slope diesel find a home?

The current U.S. diesel on-road market is around 40 billion gallons per annum. This is with a market, which relies for some 75% on gasoline and 25% on diesel as transportation fuel. "Dieselization" of the U.S. to the equivalent of Europe, where the proportions are reversed, would open a market of another 40 billion gallons per annum, even when taking into account the efficiency increase from 17 miles per gallon for gasoline to some 40 miles per gallon for diesel. One might question: Why would we expect a U.S. switch to diesel? The answer is in a crystal ball, or as others say: "might be written in the stars." Below we provide some considerations:

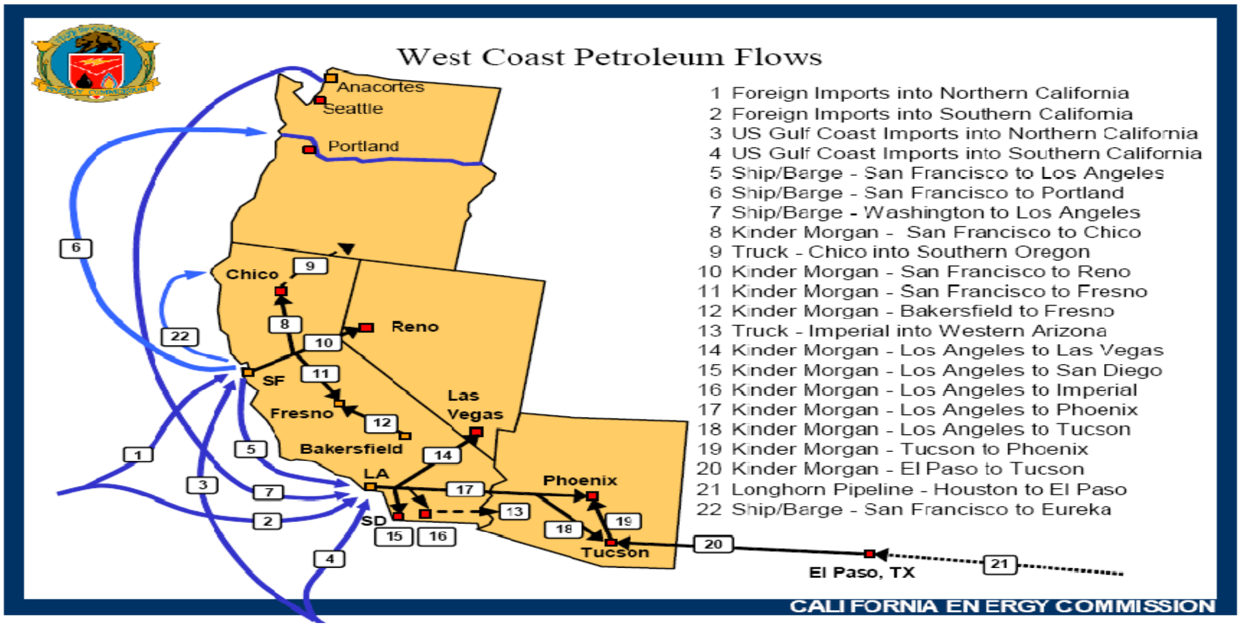
Efficiency, costs and regulations!

In theory, we have a choice of fuel; we all like to/need to drive, be it for business or pleasure purposes and at the end of the day costs will be passed on to us. Therefore, here are a series of reflections impacting this choice and those costs:

- From a supply point of view, not only the "dieselization" of the market is going to play a role, also the increasing quality requirements on diesel impact the market supply. A Baker & O'Brien consulting study for the American Petroleum Institute, analyzing the combined impact of U.S. EPA's highway and non-road diesel desulphurization rules shows a likely 825,000 bbl/day diesel production deficit by U.S. refiners in 2010[20].
- The U.S. and in particular the state of California is at the forefront of regulating the impact of car emissions caused by, in areas, exponential growth in the number of vehicles. Important bodies are the Environmental Protection Agency (EPA), the California Air Resources Board (California ARB or sometimes called CARB) and the California Energy Commission (CEC). It is therefore that we conclude that the Alaska North Slope diesel fuel can find a preferential home in the Western States of the USA, particularly in California. The latter conclusion is based on:
    1. Alaska's proximity and ease of access to the California and surrounding market,
    2. the imposing environmental requirements for diesel fuel as well as
    3. the price customers are able and willing to pay.

Let us analyze the first two factors in little more detail in the following, as the pricing will follow in a separate part of this section below:

- One important observation about demand and the home of the Alaska North Slope GTL products can be seen in the graph below. There are three major refining hubs on the West Coast; Seattle, San Francisco and Los Angeles. Products move from these hubs to the estimated 70 million people in the PADD V area. CTL products from Alaska will flow into the beginning of this supply chain allowing for both blending and neat fuel sales.



In the 1980's it was noticed[20] that regular transportation diesel-powered vehicles, accounting for about 4% of California motor vehicles, produced a disproportionate amount of directly emitted Particulate Matter (PM), about 60%. In addition to causing adverse health effects as PM, diesel PM is also a Toxic Air Contaminant (TAC). At those exposure levels it was felt that the potential cancer risk associated with exposure to diesel PM was greater than the combined risks of all other TACs. As a result, the Air Resources Board (ARB) implemented a risk reduction plan that would greatly reduce Californians' exposure to diesel PM. The plan called for low sulfur diesel fuel, 15 ppm or less, to enable the use of catalyzed particulate filters, NOx after-treatment, and other advanced emission control technologies, both for new and for retrofitted existing engines. Adopted in 1988, California diesel fuel regulations first set limits on aromatic hydrocarbon content (10% by volume) and on sulfur content (500 parts per million by weight, ppmw). These regulations, in effect since 1993, reduce emissions from diesel engines and equipment: 7% Oxides of Nitrogen (NOx), 25% Particulate Matter (PM), 80% Sulfur Oxides (SO2), and several toxic substances, such as benzene and Polynuclear Aromatic Hydrocarbons (PAHs). The regulations also provide flexibility to meet the 10% aromatic hydrocarbon limit. Refiners can use an alternative diesel fuel formulation that produces emissions equivalent to that obtained with the specified 10% aromatic reference fuel, as determined through a series of engine tests. Some refiners took advantage of this option and, instead of re-configuring their refinery, so as part of the measures, as well as building deep-desulphurization plants, sulfur free, zero aromatics GTL diesel was imported from Shell's Malaysia plant to serve as blending component and reach the same quality end result. In 2000, the South Coast Air Quality Management District (SCAQMD) adopted low sulfur diesel fuel rules for the South Coast air basin that took effect in 2004 for stationary source engines and in 2005 for mobile source engines. The U.S. EPA also proposed to extend this low sulfur requirement to off-road vehicles, so that in California there is no difference between the two grades. In 2003 amendments to the California diesel fuel regulations were proposed which would reduce diesel fuel maximum sulfur content from 500 ppm to 15 ppm, starting in mid-2006. This lower sulfur limit would align California's sulfur requirement with the U.S. EPA's existing on-road rule, and the proposed off-road rule. However, the ARB's proposed diesel fuel sulfur limit applied to both on-road and off-road engines in California in 2006. The new sulfur standard enabled the use of the emissions control technologies required to ensure compliance with the new emissions standards adopted by the U.S. EPA for 2007 and subsequent model-year heavy-duty engines and vehicles. The low sulfur requirement would further reduce the following emissions: SO2 by 88% and PM by 4%.

In addition, the California ARB has approved greenhouse gas regulation that limits greenhouse gas (CO_2, NOx and methane) emissions from passenger cars and light trucks beginning in 2009. The rule was developed under the California Bill AB 1493, adopted in 2002[21] [22].

The standards will phase in from 2009 to 2016. The average reduction of greenhouse gases from new California cars and light trucks will be about 22% in 2012 and about 30% in 2016, compared to today's vehicles. The rule introduces a CO_2-equivalent fleet average emission requirement for the categories of passenger car/light-duty truck 1 (PC/LDT1) and the light-duty truck 2 (LDT2). The standards are expressed in grams per mile (or grams per kilometer), which opens the door to measures impacting engine efficiency, exhaust emissions mitigation technology, and it also opens the door to the control of methane emission, such as can be expected from vehicles propelled by compressed natural gas. For the reader it might be of interest to know that in Europe, exhaust emission testing has always included the methane molecules. In the U.S., monitoring this greenhouse gas has never been included.

The California CO_2 Emission Standards adopted are:

California CO_2 Emission Standards In grams/mile (grams/kilometer)		
Year	PC/LDT1	LDT2
2009	301 (188)	420 (262)
2013	227 (142)	355 (221)
2016	205 (128)	332 (207)

The California ARB has based its decision on information/perception of best achievable technologies. Costs for the added technology needed to meet the rule are expected to average about $325 per vehicle in 2012 and about $1050 per vehicle to comply in 2016. According to the ARB, these increased costs will be more than offset by lowered operating expenses (better fuel economy), resulting in savings for vehicle buyers over the vehicle lifetime. The automotive industry disagreed with the ARB cost figures, claiming that the added cost will be much higher, and would never be offset by fuel savings.

The adoption of this rule makes California the only state that has regulated climate change emissions from motor vehicles. According to the ARB, seven other states consider adopting the regulation, including New York, Massachusetts, New Jersey, Vermont, Connecticut, Rhode Island and Maine, as well as the nation of Canada. California currently represents about 20% of the U.S. car market. If all of the above states and Canada adopted the rule, the number of cars required to meet the CO_2 standards would triple.

- Counteracting voices were heard from the manufacturing side: The aforementioned California ARB rule has been challenged in court by the automotive industry and, possibly, by the federal government on the grounds that it is not just an emission standard, but a fuel economy regulation subject to federal jurisdiction.
- Also, engine industry executives who met at the Reuters Autos and Manufacturing Summit in Detroit expressed their concern that the Tier 2 emission standards are the biggest barrier keeping diesels from entering the U.S. light-duty market [23].
- Support in this concern comes from the DOE's Oak Ridge National Laboratory, who released a report titled "Future Potential of Hybrid and Diesel Power-trains in the U.S. Light-Duty Vehicle Market," which forecasts a growth of 4–7% in light-duty diesel vehicles in the USA by 2012. The report states that the major obstacle preventing diesels from wider entry into the U.S. market are the stringent NOx emission limits in the federal Tier 2 and California LEV II emission standards. For new passenger cars and light light-duty trucks (LDT), Tier 2 standards phase-in beginning in 2004, with full implementation by 2007. For heavy LDTs and medium-duty passenger vehicles (MDPV), the Tier 2 standards will be phased in beginning in 2008, with full compliance in 2009. The study forecasts that diesel engines should be able to meet Tier 2 emission standards. The added cost of emission control systems, however, would make the cost penalty in diesels comparable to that in hybrid vehicles.
- It is interesting to see the report open the door to further competition in the market. From the report we quote:

"Diesel and hybrid technologies each have the potential to increase light-duty vehicle fuel economy by a third or more without loss of performance, yet these technologies have typically been excluded from technical assessments of fuel economy potential on the grounds that hybrids are too expensive and diesels cannot meet Tier 2 emissions standards. Recently, hybrid costs have come down and the few hybrid makes available are selling well. Diesels have made great strides in reducing particulate and nitrogen oxide emissions, and are likely to meet future standard."

The study predicts that by 2008 hybrids could capture 4–7% and diesels 2–4% of the light-duty market. These shares could increase to 10–15% for hybrids and 4–7% for diesels by 2012. The resulting impacts on fleet average fuel economy would be about +2% in 2008 and +4% in 2012.

Authors of the study also noted that if diesels and hybrids were widely available across vehicle classes, makes, and models, they could capture 40% or more of the light-duty vehicle market. Current penetration of diesels amounts to about 0.2% of the U.S. light-duty vehicle market. Diesel technology accounts for over 40% of the new vehicle market in Europe. The increasing diesel market is driven by good performance of modern diesel engines, superior fuel economy, and—from the regulatory standpoint—reductions in greenhouse gas emissions. [24]

We have now defined a big enough market for diesel in the U.S., elaborated on its development, but also expressed concern whether the car manufacturers are able to meet the stringent Tier 2 and California LEV II NOx emission standards. It shall, however, not surprise the reader that the anticipated GTL diesel from Qatar in the Middle East shall primarily find its way into Europe (EU). Even though the markets in the U.S. are vast and offer great potential, Europe and the EU have always been keener on diesel vehicles and quality than the U.S. In terms of numbers, data for January to March 2004 indicate that diesel vehicles are exceeding 47% of new passenger car registrations in the EU. Also, the EU has made much larger strides to increase cetane specifications than the U.S., making it an important market.

- Logistically it makes sense;
- Market wise it makes sense (with 5.5 million bbl/d the EU diesel market is 50% larger than the U.S. one);
- And…as we will show below the Europeans are ready to pay the "right" price.

This news is not withheld from us. To illustrate this, some press clips:

- The Sasol Chevron Holdings joint venture announced that its GTL project in Escravos, Nigeria, will produce 34,000 bbl/d of low sulfur fuels, which are to be marketed primarily in Europe.
- The news of the Shell Qatar announcement leaked out three days earlier and announced the market for the main product, diesel: "Shell invests $5 billion in the future of GTL. Shell is set to announce plans for a GTL plant to be located in the Middle Eastern state of Qatar, in a bid to transform Europe's dependence on lead-based fuels."[25]
- It is believed that Shell's downstream is driving their Qatar project, and the target markets for the 140,000 barrel per day "green" diesel plant are in Europe, not the U.S. [26]
- At the 10th Diesel Engine Emissions Reduction Conference (DEER) organized by the office of Energy Efficiency and Renewable Energy (EERE) of the U.S. DOE was held from August 29 to September 2, 2004 in San Diego, CA. R. Maly[27] of DaimlerChrysler told his audience: "in Qatar alone, contracts have been signed for a total 610,000 bbl/d of GTL products, coming on stream by 2011. It is estimated that by 2020 the quantity of available GTL diesel will be equal to 29% of the EU 2000 diesel demand. GTL diesel improves performance and emissions in conventional diesel engines, and can bring even higher benefit in engines specifically calibrated for that fuel."

While the GLT prospects in North America are limited by the lack of available low-cost natural gas resources, and the transportation cost of GTL diesel from the Middle East make it (too) expensive, the U.S. consumer is warmed up with the prospects of another alternative fuel—biodiesel. Its production and use has been steadily increasing and its quality and market penetration is closely monitored [28] by the National Renewable Energy Laboratory (NREL), Golden, Colorado.

So, other sources are considered in the thinking about the oil dependency of the U.S., and one obvious source is COAL…the U.S.' largest indigenous resource. In this perspective, it is hard for us to go around and not mention two exciting events for the USA, even though this report is intended to address **Gas to Liquids:**

The U.S. Congress and the Bush Administration have recognized that F-T fuels from coal and biomass can positively impact the need for additional refining capacity in the U.S. and supply of alternative transportation fuels. At the end of July, 2005, two important bills were approved by Congress and President Bush has signed them into law in August/September 2005:

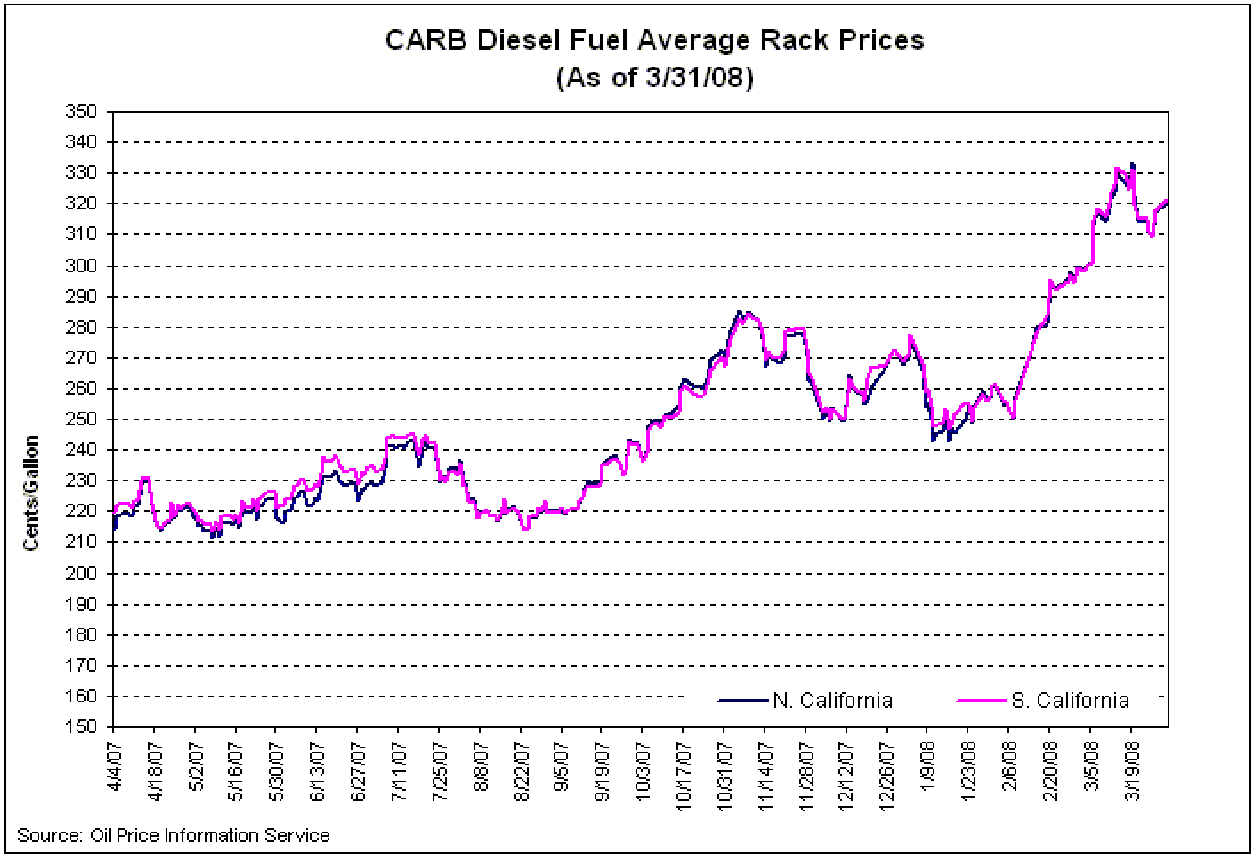
1. The Energy Bill (HR 6) provides up to $6 billion in support for clean coal gasification programs that will result in clean electricity, transport fuels and chemicals. This support is in the form of grants, government loan guarantees, cost sharing and more.
2. The Transportation Bill (HR 3) contains 50¢/gallon ($21/bbl) support for coal and biomass based F-T transportation fuel. This energy credit was signed into law in September 2005 and is effective for five years beginning in 2006. For this support of alternate fuels we would like to acknowledge Alaska Senator Ted Stevens and Congressman Don Young, who achieved this. (Note: One of the authors of this report, Richard Peterson, was involved in helping secure this legislation.)

Both of these bills change the landscape for F-T in the U.S. After years of a vacuum and complaints by technology providers that the U.S. did not "care" about alternative fuels we have again clear evidence that the U.S. Congress and Administration is going to do what the industry is asking: "provide Government support to allow F-T fuels to compete with conventional petroleum based fuels."

With respect to **market prices**, it is, from a supply point of view, not surprising that market prices for the F-T diesel only have few reference points. Some of them, presented in random order, are:

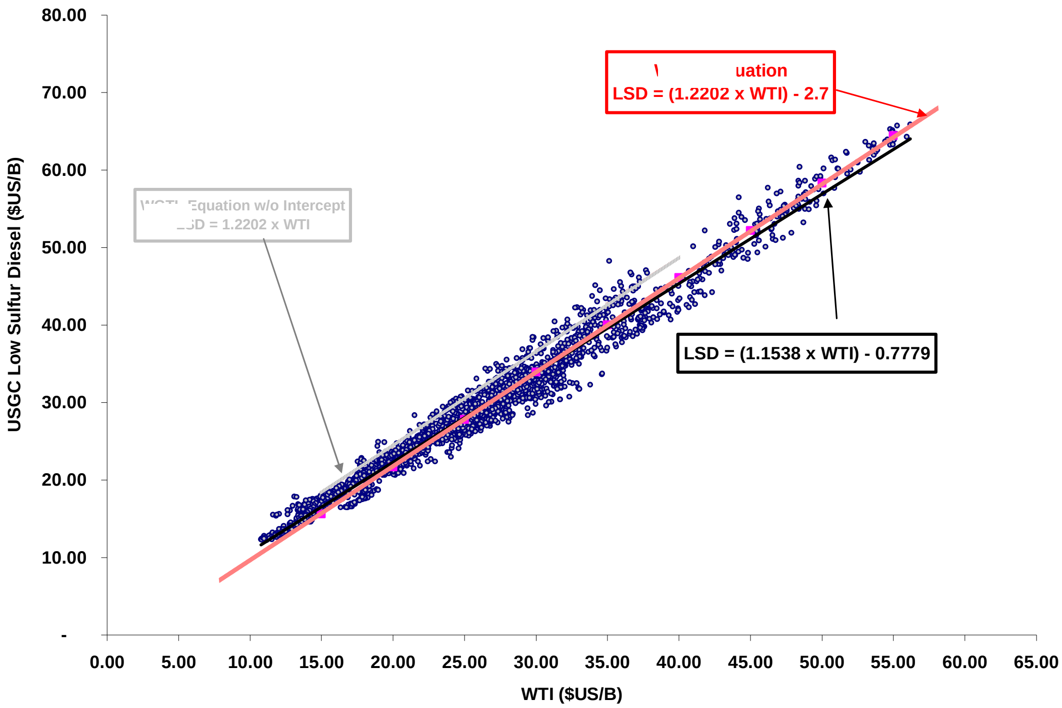
- GTL premium estimates have been made in a study by Raytheon, sponsored by the U.S. government, for the Venezuelan oil company PDVSA. They show various GTL products, including GTL Diesel, and the estimated premiums they would receive at the then prevailing price of benchmark West Texas Intermediate crude oil ("WTI") of U.S. $15 per barrel. GTL Diesel would sell (at that time) for $23.69/bbl—or about a 57% premium over crude.
- The foregoing is pretty much in line with the 70% over "average" crude [WTI has the highest value—always well above Brent crude] that Shell reportedly had been getting at wholesale from selling its GTL Diesel to two California refiners (Tosco and Paramount—now part of Valero) to use as a blend stock to meet California emission standards.
- We also know that the State of California was anxious to buy 5,000 b/d of GTL diesel and has looked at pricing from South Africa, landed in California at U.S. $65 per barrel. *An attractive price in 2004, but well below market today*. (There should also be a "cetane" premium, since GTL Diesel has 70^{+} cetane vs. 45 or so for ordinary diesel. High cetane helps reduce emissions.)
- At the U.S. West Coast, we get potentially the highest market value in the Pacific Rim. The California diesel market is the only market in the world that places a premium on low aromatic diesel. The California on-road and off-road diesel market demand is over 400,000 bbl/d with a wholesale price over U.S.$2.15/gal in August 2005. The year 2006 brought the requirement for ultra low sulfur diesel for on-road markets, and in 2010 all U.S. diesel must meet ULS requirements further increasing the costs of west coast U.S. diesel. Couple this premium market with a California Air Quality Management District emission credits and you could potentially add an additional 90¢/gallon, $990 million per year, $20 billion over 20 years to the project economics. The graph below shows the March 2008 wholesale prices for CARB diesel in California, some of the highest wholesale prices for diesel in the world.

- Contact with traders indicates that GTL, zero sulfur diesels should sell for 10–15% over 10 ppm “ultra low sulfur diesel.” A database, with references for the 10 ppm material could be found in PIRA[29]
- Since 2002, Shell has been marketing a blend of 25% F-T material in conventional diesel in Bangkok, Thailand, with a premium of 1 Baht per liter. This calculates to be a premium of $16/barrel.
- The most compelling evidence to date is Shell’s Fall 2004 sale of a 5% GTL Diesel blend at retail in Western Europe, at a premium price of Euro 0.07 per liter (that we calculate to equate to U.S.$222 per barrel of neat F-T material). Of course that market is not unlimited primarily because it is a blend of 5% F-T. *(See graph on page 23.)*



Finally, some correlation of Diesel Prices vs. Crude Oil worked up by Mr. Leigh Noda [30]. The plots have some curve fitted equations that would say that low sulfur diesel (LSD) is 1.2202 X WTI. Note that this has Y Intercepts of 0. With some imagination, one can make the intercept negative and the slopes get higher. These curves presented are linear, although the data scatter looks like it could be non-linear. Such is particularly true when capturing the limited number of data points we have at the higher WTI price level.

It seems that we should leave the factor at 1.22 x WTI, but add a factor (minus 2.7) to the 1.22 x WTI. We force the curve to better account for the points at the higher WTI prices. The best fit visually understates these data points.



Due to the low availability of F-T diesel fuels, the average properties of the world diesel pool will not change significantly; therefore, F-T diesel fuels cannot be the only solution to all diesel fuel emission issues. However, for specific local circumstances, F-T diesel can contribute to improvements in local diesel emission performance. [31]

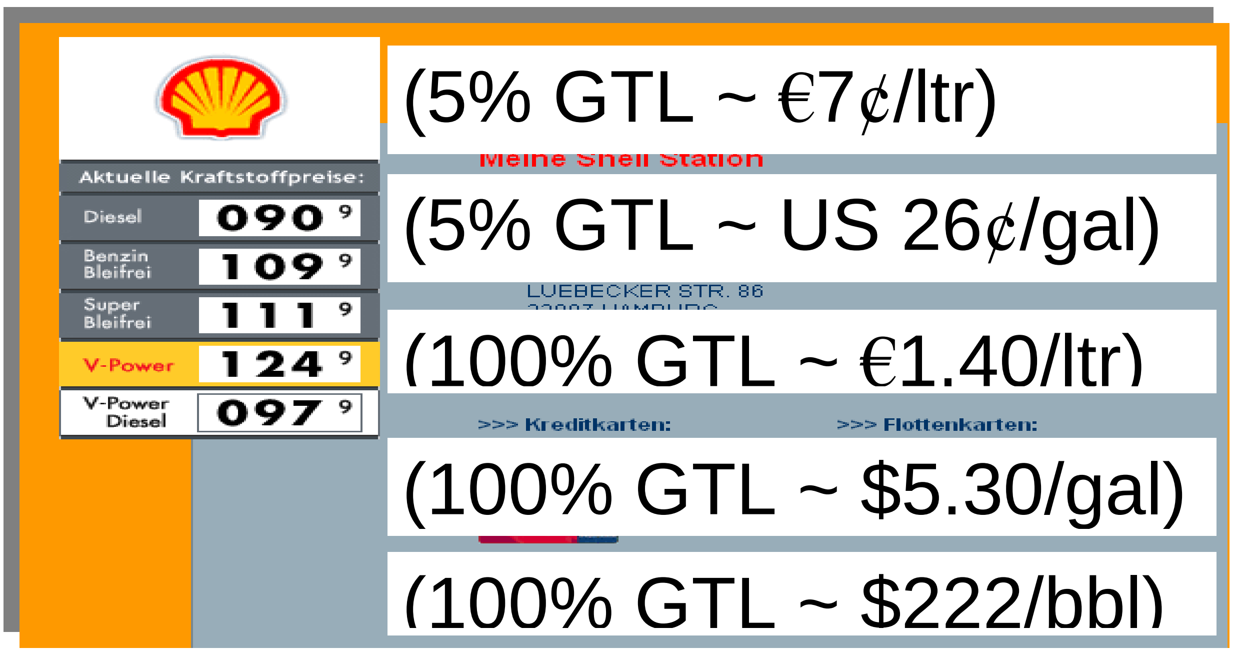
One example of this is the Californian diesel market, where the Californian Air Resources Board (CARB) requires commercial fuels to give lower emissions than a reference fuel, which has a minimum cetane number, low sulfur and aromatics. F-T diesel has excellent properties, which are far in excess of the minimum specifications in terms of cetane number. At zero aromatics and 76 cetane index, the gasoil can be used in California, in blends that meet the new stringent CARB [32] regulations.

Trends, measures and regulations in reduction of sulfur in diesel fuel are very much country dependent. In the USA, EPA regulations required the reduction of the sulfur content of diesel sold on the market to 15 parts per million by 2007. EPA regulations also required manufacturers of diesel engines, by 2007, to reduce harmful air emissions (read: soot) from diesel engines used in tractor-trailers, buses and other heavy trucks by 95% from 2001 levels. The European Union is now finalizing legislation that will mandate sulfur-free diesel for on-road use by 2009. [33]

Other examples of niche market utilization of the F-T material are the sales of “Smokeless Diesel” by Shell in Bangkok, Thailand. In this highly smog-sensitive environment, Shell markets, since 2002, smokeless-diesel, a blend of about 25% F-T diesel in conventional material for a premium value of 1 Baht/liter, corresponding to a premium of some $16.00 per barrel for the pure GTL material.

SHELL MDS (Malaysia) Sdn. Bhd. also supplied its new diesel fuel for the 2004 Olympics in Athens, Greece. The new fuel, named Shell Diesel 2004, based on Shell's GTL technology, was marketed as: "A clear liquid, free of sulfur and has very high cetane number. It offers significantly lower vehicle emission of local pollutants, such as nitrogen oxide, particulates, carbon monoxide and hydrocarbons than conventional diesel" [34]. Shell Diesel 2004 was officially launched by Shell Hellas S.A.—the Shell operating company in Greece and the official supporter of the Athens Olympic Games. The new, promotional, fuel was initially made available in selected Shell service stations mainly in the Athens region.

While Greece was the first country in Europe where the Shell Diesel 2004 was distributed, most recently Shell introduced their GTL containing V-Power Diesel in the German market. The premium they are getting for its 95% EU diesel- 5% F-T blend (7-Euro cents/liter) works out to over \$5/gallon (neat) or over \$200/bbl.



5.3.2 Kerosene

Originally, kerosene or lamp oil was the most important and desirable component obtained through distillation of crude oil. Its low volatility, energy density and fluidity give it the desired **quality** aspects. The odorless and smokeless character of F-T kerosene only adds to the desirability of this product. In its application in the aviation industry, kerosene is, since the advent of the jet engine in the 1950s, known as jet-fuel. Today, around 90% of jet-fuel (kerosene) supply is for civil aviation and the remainder for the military sector.

In 2004, world demand for jet-fuel and kerosene was 6.4 million bbl/d, or more than 2.3 billion barrels per year, a 3.5% increase over 2003. To put this in perspective, in 1992 the world demand for jet-fuel exceeded one billion barrels or over 125 million tpa. The 2004 consumption data for jet-fuel, illustrated in the table below, point to the relative importance and significant growth in **market volume** of the aviation industry. However, not only can we note growth in this industry, we also observe a shift in the market: For this one should know that, in 1992, North America accounted for slightly more than half of the world's jet-fuel consumption, mainly as result of its important domestic aviation market. At that time, civil aviation jet-fuel demand, outside North America and the Commonwealth of Independent States (CIS or eleven of the former Soviet republics), was catching up with the U.S. and had already risen from more than 300 million barrels in 1982 to more than 500 million barrels in 1992. Today, with the data from the table below in hand, we can conclude that globalization has taken effect in the aviation industry. In the decade 1992–2003, the absolute annual demand for jet-fuel in the U.S. only slightly increased to 600 million barrels, so that in 2003 the relative share of the U.S. in the total world demand for jet-fuel dropped to almost a third.

World Apparent Consumption of Refined Petroleum Products, 2004

(Thousand Barrels per Day)

Region/Country	Motor Gasoline	Jet Fuel	Kero sene	Distillate Fuel Oil	Residual Fuel Oil	Liquefied Petroleum Gases	Other	Total Apparent Consump tion
World Total	**20,865.96**	**4,813.73**	**1,632.47**	**22,517.93**	**10,080.34**	**8,028.48**	**14,365.58**	**82,304.51**
North America	**10,431.63**	**1,796.79**	**78.08**	**4,923.24**	**1,412.71**	**3,080.15**	**3,314.89**	**25,037.48**
United States	9,105.41	1,629.97	64.32	4,058.26	864.71	2,264.03	2,744.46	20,731.16
Central & South America	**1,013.56**	**181.63**	**41.33**	**1,646.69**	**816.22**	**522.54**	**1,127.09**	**5,349.07**
Western Europe	**2,876.33**	**1,093.43**	**118.73**	**6,230.44**	**2,036.82**	**1,048.08**	**2,800.91**	**16,204.74**
Eastern Europe & Former U.S.S.R.	**937.86**	**279.54**	**7.92**	**854.96**	**673.52**	**324.87**	**962.13**	**4,040.80**
Middle East	**1,075.00**	**210.38**	**179.42**	**1,391.80**	**1,250.60**	**645.51**	**786.69**	**5,539.41**
Africa	**650.71**	**153.75**	**104.62**	**924.30**	**458.40**	**219.25**	**308.44**	**2,819.46**
Asia & Oceania	**3,880.87**	**1,098.21**	**1,102.37**	**6,546.50**	**3,432.07**	**2,188.08**	**5,065.44**	**23,313.54**

(Source: EIA [13])

Therefore, it is evident that the transportation kerosene market is on a world scale basis large enough to support the volume of several additional world scale F-T plants. The **production volume** in kerosene of such typical—75,000 bbl/d—GTL plant depends on the distillation cut and, for the LTFT processes, on the severity of the wax mild-hydro cracking operation. Typically, 15–25 % of the GTL plant throughput can be put on the market as kerosene, or 10,000 bbl/d–17,000 bbl/d.

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Is it a fish? Is it a plane? ... An Alaska Airlines 737 painted to look like a king salmon taxis at Sea-Tac International Airport in Seattle, the US, at the weekend. The plane — called the Salmon Thirty Salmon — was given its intricate paint job to highlight Alaska Airlines' history of transporting huge quantities of fresh seafood from Alaska to the rest of the US. Picture: AP

In overview, the aviation market is thus of sufficient size to be able to absorb a glut of F-T kerosene without any price implications. Moreover, there are some positive characteristics of F-T jet-fuel that have not been fully exploited in the market. Fischer-Tropsch kerosene is non-smoking; therefore, it has high potential to eliminate the combustion plume of jet engines. In a world driven by more and more stringent environmental regulations, one would predict a very favorable response. In reality, however, the jet-fuel market is difficult to penetrate. This is because the aviation industry is a highly regulated and controlled industry, adhering to strict quality standards and norms. Additionally, the aviation industry swings, depending on the routes flown, forward and backwards in the perpetual dilemma of minimum aircraft weight versus maximum action radius of the plane.

Only the Royal Air Force (Britain) accepted the F-T jet-fuel very rapidly upon its introduction. The British military recognized the importance of the cleaner burning F-T kerosene, which reduces emissions, producing no sulfurous oxides and fewer particulates, and extends engine life. Most importantly, the smokeless engine largely reduces the infrared detect-ability of the aircraft and hence is of strategic importance to the military. In South Africa, Sasol began supplying a Coal-To-Liquids (CTL) jet-fuel blend, which consisted of a 50/50 blend of coal F-T based kerosene (jet-fuel) with conventional kerosene in 1999. Their test program did not end until they finally received approval in May of 2003 and were then able to sell this fuel long term. In April 2008, global aviation fuel specification authorities, including the United Kingdom Ministry of Defense, approved Sasol's wholly synthetic jet-fuel as Jet A-1 fuel for commercial use in all types of turbine aircraft. In the foreseeable future, the U.S. ASTM will provide synthetic jet-fuel testing specifications.

In recent years, the effort has been followed up by the U.S. Military. After various techno-economical studies, a U.S. Air Force B-52 took off from the Californian Edwards Air Force Base in September 2006 with two of its engines powered by a hybrid fuel, a 50/50 blend of synthetic and regular kerosene. The other six engines used traditional jet-fuel. The flight, which lasted three hours, demonstrated that the engines with the new fuel operated as well as the engines with traditional jet-fuel. With increasing availability of GTL aviation kerosene, its popularity rises. Recent announcements indicate that Shell is working towards certification of its products.

In overview, a market is developing. The U.S. Department of Defence announced plans to buy up to 760 million litres (200 million U.S. gal) of synthetic F-T kerosene for use in a 50% blend with JP-8 and JP-5 (used by the U.S. Navy), but no contracts have been awarded. [13]

The Air Force, which uses the majority of the fuel for the military and 10% of all U.S. jet-fuel, will have certified all of its equipment for use on a minimum 50-50 F-T blend by 2011 and fully expects to purchase this volume by 2016. This will represent 5% of the U.S. total jet-fuel production or 400 million gallons annually. In discussions with the military they fully expect the commercial jet industry to follow suit in order to reduce emissions. Qatar Airways has already announced it will begin flying its new Airbus planes with a mixture of F-T and kerosene to be the first commercial airline in the world to go "green".

From the above table it is also evident that the **non-transportation kerosene market** is on a world scale basis large enough to support the volume of an additional world scale F-T plant. The typical output volume in kerosene of such plant, 10,000 bbl/d–17,000 bbl/d, happily disappears in the 1.8 million bbl/d consumers market. Contrary to the transportation component, however, there is a considerable spread per country in the use of the stationary type of kerosene. In the U.S. for example, one has the impression that its utilization has, apart from incidentally used backup, turbine driven, electricity generators, returned to the "lamp oil" application for a cozy ambiance. Therefore, it provides for a market to sell the odorless F-T kerosene, pleasantly fragranced and brightly colored, in bottles as lamp oil for premium prices. On the contrary, in the Far East the application of small kerosene space heaters is widespread. Therefore, it is not surprising that odorless F-T kerosene in gallon quantities enjoys widespread popularity in Japan. One can only imagine the potential of the Chinese market in this respect, should wood and coal stoves be replaced by the kerosene heaters.

In addition, the ratio of stationary over transportation use indicates an interesting demographic behavior: without highlighting behavioral patterns or pulling conclusions, the comparison of the ratios in the United Kingdom versus the United States is at least striking.

World Apparent Consumption of Distillate Petroleum Products, 2002

(Thousand Barrels per Day)

Region/Country	**Jet Fuel**	**Kerosene**	**Distillate Fuel Oil**
World Total	**4,477.4**	**1,773.5**	**20,907.4**
United States	1,620.5	43.3	3,775.9
Japan	219.9	511.7	1,212.5
India	49.3	220.0	791.6
Indonesia	28.9	200.8	445.2
Korea, South	74.0	164.6	402.8
Iran	17.2	144.0	431.8
United Kingdom	217.3	83.0	509.7
China	128.9	67.1	1,568.0

World Apparent Consumption of
Distillate Petroleum Products, 2003
(Thousand Barrels per Day)

Region/Country	Jet Fuel	Kero sene	Distillate Fuel Oil
World Total	**4,813.73**	**1,632.47**	**22,517.93**
United States	1,629.97	64.32	4,058.26
Japan	222.71	472.60	1,165.93
India	60.91	198.42	838.79
Indonesia	41.89	203.56	473.95
South Korea	84.97	122.32	417.06
Iran	17.23	133.08	471.09
United Kingdom	256.12	85.02	526.27
China	179.96	49.57	1,975.81

In terms of **market pricing** for the F-T kerosene, there are not enough statistical and/or public data points. This is partially caused by the difficult penetration of the material in the aviation transportation market, partially also because of the sales of the product on the stationary market, where lamp oil and space heater application command premium prices. For evaluation purposes, however, it has been suggested that a small premium of $4.00/bbl over straight-run middle distillate pricing should be achievable.

On this basis and taking into account that the Far East/Singapore is the most prominent market locator, a price equation suggested is

F-T Kerosene (U.S.$/bbl) = Crude Oil (FOB Dubai –U.S.$/bbl) + 8.88

5.3.3 Naphtha

From the historic perspective, one might remember that the naphtha or the gasoline precursor from the F-T process stands in clear contrast to the same fuel produced by “hydrogenation” of coal. In the World War II time, the synfuel industry targeted the production of high octane, high-density gasoline for the Luftwaffe, and lesser quality gasoline for vehicles and diesel for heavy equipment and ship. The requirements of high octane, high-density aviation gasoline for the Luftwaffe precluded the direct use of F-T gasoline with its paraffinic character. However, it was found that the “hydrogenation process” and the Fischer-Tropsch process yielded remarkably complementary products. The gasoline fraction retrieved from the hydrogenation process was highly aromatic and had a high octane. The naphtha from the F-T process was, through its olefin content, moderate in octane (40–50), but very suitable for alkylation, with the resulting octane improvement. The German gasoline was, therefore, the result of blending hydrogenation liquids with F-T alkylate and Tetra Ethyl Lead.

From a **quality** point of view, the F-T naphtha is not very exciting for the motor gasoline market. Nevertheless, it has all the potential to be a gasoline blending component, paraffinic, sulfur free and has, through isomerization, a low to moderate Research (RON) and Motor Octane Number (MON).

We have mentioned before that there is a difference between the straight run naphtha from the cobalt catalyst and the iron catalyst. Straight run product from the latter catalyst is more olefinic and has a higher RON. After hydrogenation/isomerization, this difference is basically gone. For evaluation purposes, an estimated RON of 60 can be used. For blending purposes, one should add about 10 more points. This is because in practice octane numbers do not blend linearly. To accommodate this, complex blending calculations employing blending octane numbers as opposed to the values for pure hydrocarbons are routinely employed. Although still not exactly indicative of the actual blending octane number for a specific gasoline composition, the blending octane numbers are more representative.

Needless to say, the existing **market volume** of gasoline is enormous. The above tables show a worldwide demand for motor gasoline of over 20 million bbl/d.

The **plant production volume** of naphtha, which a typical world scale F-T plant can put on the market, is dependent on the operating regime: the High Temperature Fischer-Tropsch (HTFT) process will produce significantly more light products, and hence gasoline precursors, than the Low Temperature F-T (LTFT) process. For the HTFT process, as practiced by Sasol and PetroSA, comfortable numbers are 35% of total design throughput. The LTFT process will only produce circa 20% of its design capacity in naphtha. Therefore, typical production volumes for a world scale plant of 70,000 bbl/day–80,000 bbl/d would be 15,000 bbl/d to 25,000 bbl/d naphtha production. Thus, if we put this volume in perspective with currently planned GTL capacity, there is some additional 50,000 bbl/d of GTL naphtha forecasted to come on the market by 2015. Although we will see hereinafter that GTL naphtha more than likely will receive a premium in the chemical feedstock market, one can safely conclude that the available volume will barely make a dent in the motor gasoline market.

Apart from the naphtha gasoline applications, new developments in the market are encouraging. Below we give three examples:

5.3.3.1 F-T Naphtha – Stationary Diesel Fuel Application

With product upgrading such as hydro-treating, the naphtha's octane reading generally drops as the molecules get saturated, which is not surprising because of the RON for pure normal paraffins: n- Hexane: 24.8, n-Heptane: 0, n-Octane: -18, n-Nonane: -18, n-Decane: -41. This, surprisingly, makes hydro-treated F-T naphtha an ideal candidate for very light, volatile, diesel fuel. This is because one general rule in the fuel industry is: Material with a low octane has a great cetane, and vice versa!! To illustrate this point, the following table puts the F-T naphtha in perspective to reference diesels and the F-T diesel.

	Californian CARB Reference fuel Specification	European Union Specs	F-T Diesel Commercial Shell Specification	F-T naphtha
Cetane number	48 minimum	49 minimum	76	60
Density (kg/m³)	N/S	820-860	780	690
Sulfur (ppm)*1)*	500 15 (2006)	500 (1996) 50 (2005) 10 (2008)	n/d	n/d
Aromatics (% m/m)	10 maximum	N/S	n/d	n/d
Cloud point (ºC)	-5	N/S	1	N/S
CFPP (ºC)	N/S	+5 to -20*	-2	N/S
Distillation 90% recovery (ºC)	288-338	N/S	340	N/S
95% recovery (ºC)	N/S	370 maximum	350	N/S

* depending on climatic band chosen
N/S = No Specification
n.d. = not detectable/below detection limits

CARB = California Air Resource Board
CEN = Central European Norm

Increasing developments of the diesel engine are made and promise high efficiency with low emissions. One of those is the development of the Homogeneous Charge Compression Ignition (HCCI) engine. In this engine, the fuel and air charge undergo rapid mixing and simultaneous compression, giving a spontaneous combustion reaction throughout the cylinder. The resulting low temperature and fast reaction gives low Nitrous-Oxides (NOx) emissions. The HCCI engine does, however, require precise control of the auto-ignition of the mixture, high exhaust gas recycle to control the combustion rate and a special volatile fuel. That is where the F-T naphtha offers a promising pathway.[35] Tests performed by Southwest Research Institute have confirmed this [36] . With these next generation diesel engines expected to be in the market place by 2015, it could be that the F-T naphtha will see an even higher netback supplying this market than the current petrochemical market.

5.3.3.2 F-T Naphtha – Gas Turbine Fuel Application

The prospect of having abundant and hence, lower value, synthetic value available opens the “niche market” of turning this low value naphtha stream into high value electricity and steam using a high efficiency combined-cycle gas turbine while achieving natural gas emissions levels. Earlier in 2007, LPP Combustion[37] demonstrated that synthetic liquids can burn as cleanly as natural gas. Synthetic JP-8 and naphtha were tested using a commercial “state-of-the-art” dry low emissions gas turbine combustor and achieved natural gas level emissions for nitrogen oxides, carbon monoxide, sulfur oxides, and particulate matter. Synthetic liquids are, obviously, cleaner fuels than their petroleum-based counterparts because the typical contaminates found in oil, such as nitrogen, sulfur, are removed during the F-T process. From the chemical composition we know that F-T naphtha has similar combustion characteristics as natural gas or LNG, while it is much easier to store.

5.3.3.3 F-T Naphtha – Fuel Cell Feedstock Application

Similar as its use for gas turbines, F-T naphtha should be an attractive feedstock for fuel cells. Being sulfur free and hydrogen rich is a pre-requisite for fuel cells and obviously F-T naphtha fulfills these requirements. Additionally linear hydrocarbons are very easy to "unzip," or in other words allow for easy removal of the hydrogen from the carbon chain.

F-T naphtha comes close to the "universal" fuel which the military is seeking so eagerly.

In terms of **market value** in the fuel or gasoline pool, a safe assumption is a straight link to Platt's naphtha quotations. There have been evaluations made; assigning a penalty of up to U.S. $10.00/bbl to F-T naphtha, claiming that its paraffinic character makes it a less desirable blending component. In actual practice there may even be a monetary benefit for the refiner to use this low density material: we know at least one refiner who sells in volume but pays tax on weight of the gasoline sold!

5.4 Specialty Markets for F-T Products

The specialty market for F-T products is enormous and this section can unfortunately only pay attention to the mainstream products. From there a world of chemistry can be performed leading to the most diverse derivatives. The best way of illustrating this is by referring to the enormous market or empire, which Sasol, the leader in the synthetic products, has built up. Recently, we came across an article that mentioned that Sasol has now opened an office in Shanghai, China, to market its solvents. It quoted: "*Sasol Solvents operates plants in South Africa and Germany and supplies a wide range of products, including glycol ethers, C3/C4 alcohols, esters and acids, ethanol, ethyl acrylate, fine chemicals and aldehydes, glacial acrylic acid, ketones, methanol, n-butyl acrylate and mining chemicals. These are used in aerosol, agricultural, cosmetic, fragrance, mining, packaging, paint, adhesive, pharmaceutical, polish, printing and other applications.*"

5.4.1 F-T Naphtha - Ethylene Cracker Feedstock Application

Ethylene is one of the basic building blocks of the petrochemical industry and the precursor of widely used plastic polyethylene and other derivatives in the plastics industry (polyethylene bags, polypropylene bags and fabrics, etc.). Most anything in bulk plastic starts with ethylene or propylene. The primary source of these molecules are the "steam crackers," also called "ethylene crackers" or "naphtha crackers," depending on where and who has been naming them. In the U.S., the primary feedstock for these crackers are natural gas liquids (ethane, propane, butane) because of their availability. In most other parts of the world where natural gas production is less prevalent, naphtha is the feedstock. The name "steam cracker" is such because the feedstock is heated together with steam to high temperature (~1500–1600 ˚F) to "crack" the molecules to ethylene and propylene. The same facility is called "ethylene cracker" as ethylene is the primary desired product. The manufacturing is, however, inevitably coupled with the production of propylene.

Crackers are located in and outside of refineries around the world. More importantly, they need to have users of the commodity chemical in close proximity to minimize transporting the ethylene and propylene, which are light gases. In most of the world, naphtha is a logical feedstock since there is not as much need for it since gasoline demand is not like the U.S. In the U.S., almost all naphtha is used for gasoline. The exception to this is the low octane, paraffinic naphtha since it makes poor gasoline and tends to be good cracker feed.

The naphtha produced in the Fischer-Tropsch process falls into this category as it is highly paraffinic with a zero (produced by iron catalysis it can be very low) sulfur, and negligible naphthenics and aromatics content. Because of the low aromatics, its upgrading to the required high octane numbers of the gasoline pool poses problems, but it is ideal as a feedstock for ethylene cracking.

Light paraffinic naphtha is the most efficient liquid feedstock for ethylene cracking. GTL naphtha paraffin content is typically higher than 98%. This is considerably higher than the 65% to 75% of typical open-spec naphtha and ~85% of typical, full-range naphtha. It is even higher than the ~92% of a highly paraffinic, light naphtha such as Saudi A-180, which is one of the best products currently available for this application.

The premium for F-T naphtha is determined by the incremental yield of the ethylene. In general, an additional ethylene yield of 10% or more can be expected. However, this premium is sometimes reduced because the naphtha will not make much aromatics (which can also be valuable), and naphtha is purchased by weight, not volume, since the cracker products are sold by weight. GTL naphtha is low density, probably the lowest possible. Perhaps superfluous, although we need to point out for the reader that the chemical markets typically handle their capacity, production and markets by weight (generally expressed as metric ton per annum – tpa- or million pounds – million lb-).

The olefins business is a complex business. Many issues must be managed including feedstock costs and optimization, product slate variability, impact of new technologies, end-use market outlooks, pricing and margin issues, operating rates, etc. In this business equation, the fortunes of the ethylene business and the propylene business are generally linked. The markets for ethylene and propylene are huge in size and have experienced rapid growth. However, propylene continues to be viewed by many as a by-product of refineries and ethylene plants, or at best a co-product. In terms of market for the end products—ethylene and propylene—we are looking at large volumes: for example, we can mention here that the current (2006) world market for polyethylene is little over 60 million metric tons; for polypropylene it is almost 45 million metric tons. With a forecasted [34] average growth of 4% per year, we expect to reach world market demands of 75 and 55 million metric tons by 2012. In this world-market, the Chinese market outperforms the rest of the world with an estimated 7% annual growth increase.

Currently, we find similar growth figures in the U.S., which, with a tight balance of supply and demand, is turning petrochemicals into a seller's market. Market supply has been shaped by a deep business trough from 2001 to 2003—when producers were hit by excess capacity, weak demand, high costs, and lost international competitiveness. Roughly 4 billion lb of capacity has been idled or closed for good in the 55 billion-lb North American ethylene market since 2001. The only new capacity in 2004 was a 1.1 billion-lb-per-year expansion at Shell Chemical's Deer Park, Texas, complex and 400 million lb from Huntsman's restart of its Port Neches, Texas, line. In 2005, a 550 million-lb expansion at BP's Chocolate Bayou, Texas, complex was commissioned. As a result, effective operating rates climbed from about 85% at the end of 2002 to more than 97% at the end of 2005.

Global naphtha demand is also increasing due to growing demand for basic petrochemicals. Demand is currently more than 5 million bbl/d (220 million tons per year -tpa) and will grow to more than 78 million bbl/d (310 million tpa) by 2015.[14] The projected GTL naphtha supply of 0.1 million bbl/d (4 million tpa) would meet less than 2% of total global demand.

The key demand region for naphtha is Asia-Pacific, which already has a growing deficit. This deficit will reach nearly 90 million tpa by 2015. North America and Europe will remain broadly balanced in naphtha at that time.

The tightening market is driving up prices and margins. From December 2002 to December 2004, average ethylene prices nearly doubled to 41.5 cents per lb, according to the Houston-based consultancy group Chemical Market Associates Inc (CMAI). Meanwhile, ethylene cash profit margins—prices minus the costs of production—have increased from not much more than a penny to 18 cents per lb. The propylene market has become even tighter than the ethylene market. According to the CMAI, contract prices for chemical-grade propylene have climbed to 45.0 cents per lb—higher than the ethylene price for the first time in more than 15 years. The high prices for co-products such as propylene have given naphtha-based crackers an edge over the ethane-based crackers that represent about 70% of ethylene output in North America. The naphtha-based crackers get so much additional value out of their by-products that it gives them better margins. Hence, F-T naphtha is a welcome feedstock for the naphtha crackers.

5.4.2 F-T Naphtha – Solvents Application

Linear alkanes (also referred to as normal alkanes or n-alkanes) are known as solvents. For instance, in the food industry, n-hexane is a well-known extracting solvent. In solvent de-asphalting techniques for removing heavy asphaltenic compounds from residual hydrocarbon oils, n-butane and n-pentane are often applied as extracting solvents and in dry-cleaning. In the adhesive and rubber industry, n-pentane and n-hexane are known solvents. These lower n-alkanes are suitable for application in these processes and have been selected because of their volatility.

The C_5-C_8 hydrocarbons from the F-T process provide for the same characteristics. However, taking into account their paraffinic nature, these Fischer-Tropsch products allow for an additional market opportunity. **Being completely free of aromatics and sulfur compounds, together with low odor, these solvents fit particularly well in the current environmental development of the market**. Presently, solvents in this carbon range, particularly hexane and Special Boiling Point (SBP) type are used in oil-seed extraction and other food quality processing. In view of these applications, they sometimes need to be guaranteed low in aromatics, particularly in benzene. The F-T naphtha fraction is eminently suitable for these applications.

The market represents a wide variety of different solvents of which the worldwide demand in aggregate is estimated to be over 2,000,000 tons per year. Environmental awareness, volatile organic compound regulations, and solvent-free technologies such as powder coatings have combined to dampen the outlook for the solvents business in the USA. The 2004 U.S. market volume was quoted as 2.7 billion lb per year, of which 60% is hydrocarbon solvents and 40%

oxygenated solvents. The industry has seen little or no growth, and a slow U.S. market decline because of the new rules has been predicted for the years to come.

5.4.3 F-T Kerosene – n-Paraffins - Detergent Feedstock Application

Via the hydrogenation of raw F-T wax, specialty hydrocarbons of high paraffinicity are produced. These streams are otherwise produced by much more elaborate extraction processes from crude oil based kerosene. The normal paraffins in the kerosene boiling range have two important markets, the major being the detergent feedstock markets, the second one is the solvent market.

Normal paraffins of the C_{10}–C_{17} quality are the feedstock for production of detergents. For the purposes of this discussion, normal paraffins are linear, aliphatic hydrocarbons of C_{10}–C_{17} chain lengths that are usually separated from kerosene or light gas oil fractions of crude oil using molecular sieves. Their major use is as a raw material for the production of olefins or mono-chloro-paraffins used to manufacture Linear Alkyl Benzene (LAB). LAB is subsequently used for Linear Alkyl Sulfonate (LAS) production.

Normal paraffins, the C_{10}–-C_{17} fraction from the F-T plant, are thus an ideal feedstock for LAB and subsequent for LAS production. Hence, in this market analysis LAB and LAS are the most important products to examine. LAS has been the major surfactant used in detergents for more than thirty years, continues to represent a substantial portion of the surfactants market today and experiences an ever-increasing use around the world. LAS is a main component of laundry detergents and other cleaning products that was created to help put an end to foaming in rivers and streams. The use of LAS is as follows: LAS for laundry detergents, 70%; LAS for light-duty dish-washing liquids, 15%; LAS for industrial cleaners, 12%; LAS for household cleaners, 3%. (The chemical also finds uses in herbicides, wetting agents and personal care products.)

Normal paraffins are conventionally produced by either extraction of normal paraffins from a paraffinic-based kerosene stock or by polymerization of ethylene. Although the process routes are generally using low-priced feedstock, i.e., low density kerosene and ethylene cracker residue, they are relatively expensive processes. The latter is mainly caused by the fairly low selectivity in desired products. In the surfactant, manufacturing the normal paraffins are further worked up in a multi-step processing route. A main route is to firstly convert the n-paraffins into the alpha-olefin form. Such alpha-olefins are produced from the n-paraffins by processing in a selective dehydrogenation process, like the Universal Oil Products (UOP) Oleflex process. Subsequently, the alpha olefins are reacted with benzene to form the linear alkyl benzene. LAB, which currently represents one-third of the active ingredients in detergents worldwide, is then used to produce linear alkyl benzene sulfonate (LAS), a major surfactant in the detergent industry.

Via simple hydro-cracking of raw F-T wax, specialty hydrocarbons of high paraffinicity can be produced with very high selectivity. It is evident that such direct production of this material by the F-T synthesis route is attractive in comparison with the conventional route. Their applicability as detergent feedstock has been demonstrated. The purity of the products satisfies all the performance requirements in the production of linear alkyl benzene, chlorinated paraffins and paraffin sulphonates. By tuning the distillation, virtually pure C_{10} - C_{13} and C_{14} - C_{17} fractions, by Shell respectively called Light Detergent Feedstock (LDF) or Heavy Detergent Feedstock (HDF) or SARAPAR 103 and SARAPAR 147 by their trade names, can be obtained. The LDF is used most widely as surfactants in laundry applications where its higher than normal

C_{13} content gives rise to improved detergency; the HDF is used in making chloro-paraffins of exceptional quality in terms of heat stability and color. The bio-degradability, which is critical in such applications, has been demonstrated to be fully satisfactory: On the one hand, there is only a limited amount of branched hydrocarbons present; on the other hand, they are mostly biodegradable methyl groups.

The demand for n-paraffins is strongly coupled to the detergent precursor LAB, which in itself depends on the LAS market and price development. Demand for LAS in North America "fell sharply" in the 2000–2005 period, mostly due to detergent reformulations away from LAS to lower priced surfactants. However, these declines in North America are being offset by advances in developing regions of China and India, where LAS growth is pegged at 2%–4% annually. These geographical patterns also reflect the growing popularity of liquid detergents in North America, and the preferences for powdered detergents in Asia and Western Europe. (Liquid detergents generally use less LAS and more alcohol surfactants such as alcohol ether sulfonates and alcohol ethoxylates, while more LAS is used in powdered formulations.) We will here, however, discuss the closest demand sector for linear alkyl paraffins, being the LAB market.

The LAB market is dominated by Sasol Ltd. of South Africa, mainly through its acquisition of Condea Vista, based in Hamburg, Germany, and Petresa, based in Madrid, Spain. The acquisition of Condea, formerly a unit of RWE-DEA AG, was completed in March, 2001 for €1.295-billion. The objective was to improve Sasol's position in the Olefins and Surfactants (O&S) business, to vertically integrate Condea to Sasol's required standards and link it to the Sasol proprietary Fischer-Tropsch technology processes. At the end 2006, however, Sasol admitted that these goals had not been achieved and that it would sell off their O&S business. Such sale of the company's O&S business took, under the market conditions that we'll discuss below, longer than expected. While in March of 2007, Sasol expressed hope to have it wrapped in 2007 [37], they decided thereafter that the offers received were below "fair value." Sasol has now has identified restructuring and other opportunities to improve business performance and, thus, will stay in the LAB business.

Both Sasol and Petresa have production in Europe and North America. Petresa also has a plant at Camaçari, Brazil. They are the main exporters of LAB. Other LAB producers have only regional production.

	World Capacity 2005	**World demand[38] 2005**
	3.4 million tons	**2.487 million tons**
Asia Pacific	46%	42%
North America	15%	16%
Latin America	10%	11%
Western Europe	18%	10%
Africa/Mideast	10%	17%
Others	1%	4%

CAPACITY OF LAB PRODUCERS IN EUROPE, AMERICA & MIDDLE EAST [34]

Producer	**Location**	**Capacity (in thousands of tons per year)**
NORTH AMERICA		
U.S.A		
Sasol	Baltimore , MD	136
	Lake Charles , LA	109
Huntsman	Chocolate Bayou, TX	181
CANADA		
Petresa	Bécancour , PQ	120
LATIN AMERICA		
Brazil		
Petresa	Camaçari	220
Venezuela		
Quimica Venoco	Guacara	80
Argentina		48
WESTERN EUROPE		
Italy		
Sasol	Augusta	220
	Porto Torres	100
Germany		
BASF	Ibbenburen	50
Spain		
Petresa	San Roque	220
EASTERN EUROPE		
Russia		50
MIDEAST/AFRICA		
Egypt		60
Iran		125
Iraq		50
Qatar		110
Others		18

The world market of linear alkyl benzene, which until 2000, used to be balanced, is reported to be oversupplied because of new capacity, keeping operating rates around 80% to 82%. Capacity in the Mideast/Africa region grew 30% in 2006 to 353,000 tpa. Capacity there is expected to grow further to 523,000 tpa. As a result, smaller plants are shutting down under the force of competition. A recent example can be found in India: In early 2007, Indian Petrochemicals Corporation has closed its 43,500 tpa linear alkyl benzene plant at the Vadodara complex, Gujarat, India. The plant is reported to have been closed mainly because of its so-called small size relative to world scale LAB plants operating elsewhere.

New capacity coming into operation this year (2007) in Saudi Arabia and Qatar are expected to drag operating rates below 80%, and remain at similar levels for the next few years. Global demand growth has historical (1995–2000) been around 5% per year; since then (2004–2006) global growth has been about 2% per year, with 2%–4 % in Asia.

With competition in the market, producers will need to be innovative with existing assets to reduce dependence on detergent formulation trends and other factors. Huntsman is, for example, considering diversifying beyond detergent products at its Chocolate Bayou, TX plant. For others, feedstock integration has become the priority amid volatile and surging costs. The thread in Asia comes from competition: A big buildup in Southeast Asian capacity for oleo-alcohols (long-chain alcohols derived from the fats and oils of plants) is making these feedstocks competitive with LAB as starting materials for surfactants. In fact, oleo-alcohol prices have dropped below those of LAB in many instances. More than two thirds of the 1.7 million tons of higher (long-chain) alcohols consumed in 2005 went into the production of three surfactants: alcohol ether sulfates (34%), alcohol ethoxylates (22%), and alcohol sulfates (17%).

Oleo-alcohol feedstock seems to be most competitive with LAB in Asia because that is where the oleo-alcohol capacity buildup has been the greatest and where transportation costs to surfactant manufacturing facilities are the lowest. Keeping oleo-alcohols from being competitive with LAB as surfactant feedstock are the high prices of the ethylene oxide used in the ethoxylation process. Anticipated new capacity for ethylene oxide has been delayed, causing prices of ethylene oxide to stay elevated, and adding to the costs of such surfactants as alcohol ethoxylates and alcohol ether sulfates. Valuable information on LAB market developments can further be found in “The LAB Marker Report” by Colin A. Houston and Associates, Inc.

In terms of price, historically, between 1995 and 2000, LAB yielded a high of $0.595 per pound (list-price, detergent alkylate, straight-chain, dodecyl-benzene, tanks, barges, f.o.b.) and a low of $0.545 per pound on the same basis. Currently it is $0.595 per pound, on the same basis. Higher crude oil prices have been at the root of rate hikes by several major surfactant manufacturers over the past year. Counterbalancing this, the recent opening of two new Middle Eastern plants for linear alkyl benzene (LAB) has helped to take some of the steam out of price pressures. Therefore, while prices were up near the end of 2006, they didn't leap off the charts and more capacity and competition should keep LAB prices down in 2007.

In conclusion, surfactant producers are reeling from the effects of rising feedstock and energy costs. Stronger crude oil pricing is making a bad situation worse and is adding to pressure on LAB margins. Normal paraffin, however, remains tight, resulting in worldwide LAB price increases. Installed capacities of normal paraffins are ample, but the real influence on normal paraffin supply is the supply of normal paraffins-rich kerosene, which is less available. There is good news for the F-T n-paraffins!

[For the reader: the above LAB price of $0.595 per pound, 15% discount for margin and processing and a current benzene price of $3.50 per gallon, allows a sales value for F-T n-paraffin’s of US$ 135 per barrel.]

5.4.4 F-T Kerosene Fraction – Solvents Application

The term solvent is used in relation to substances, which have the ability to dissolve or thin out other substances without chemically changing them. After water, it is mainly organic solvents that are used. They are normally liquid under normal conditions (room temperature), but have a tendency to escape into the air, which is why they are classified as being volatile. There are also natural solvents, which are manufactured from natural vegetable products with few modifications. However, the most commonly used solvents are created from crude-oil and natural gas liquids.

Solvents are used as additives in industrial production e.g. in the adhesive, paint, varnish and household cleaning agent industries. They are also used as components in pharmaceuticals, cosmetics, cleaning and paint stripping agents. Some solvents have proven to be harmful or are suspected of being harmful. This has led to a flood of regulations for the protection of health and the environment, which have been put into practice by industry. Some solvents are now completely prohibited, others are limited in their application areas and many substances are now being recycled and re-used. The vast quantity of legal measures has brought about major changes in the solvent market.

Market conditions have changed in response to changes in the economic field. Reasons for this include the stark rise in the price of raw materials and a very high economic growth rate in Asia, while the markets in Western Europe and North America are stagnating. This has led to the partial closure of some plants of Western companies or the relocation of plants to cheap-labor countries. Similar developments have also occurred in many branches where solvents are used. A strong dynamic has also formed within the solvent market itself. Due to legal measures and a change in the environmental awareness of consumers, demand for chlorinated and hydrocarbon solvents has been replaced by demand for oxygenated and "natural" solvents.

One of the attractions of F-T linear paraffins is that they are aromatics-free, odorless solvents for the paint industry. However, paint market maturity, volatile organic compound regulations, and solvent-free technologies such as powder coatings have combined to dampen the outlook for the solvents business in the USA and Europe. Government regulations in the United States and Europe, especially regarding air pollution, are a driving force behind the adoption of new, solvent-free coating technologies such as radiation-cured coatings or water based paints. In 1998, the EPA issued its final ruling on the permissible VOC limits for architectural, industrial maintenance and automotive refinish coatings. The regulations became effective in late 1999. In 1999, in the European Union, the VOC Emissions Reduction in Industrial Installations Directive was adopted by the Council of Ministers, setting out targets for solvent emission reduction. It applies to the main types of organic solvent-using installations, including painting processes in a contained plant as well as paint manufacture, with the aim of an emission reduction of 50% from the 1990 levels. Existing facilities have until October 2007 to comply with the maximum allowed emission standards imposed by the directive. New and reconstructed facilities must comply by 2004.

The market represents a wide variety of different solvents of which the worldwide demand in aggregate is estimated to be over 20,000,000 tpa. We already mentioned above that the solvents market looks to developing countries and greener technologies to drive growth. The overall world demand for solvents is forecasted to grow at 2.3% per year through 2007, according to a recent study by the Freedonia Group. Demand for hydrocarbon and chlorinated solvents will continue its downward trend as a result of environmental regulations, with oxygenated and green solvents replacing them to a large extent. Solvents demand in the U.S. is projected to increase to 12.5 billion pounds in 2010, valued at U.S. $4.4 billion. Manufacturers of coatings, printing inks, adhesives and other products remain committed to reducing solvent loadings in their products, as evidenced by the growing preponderance of water-based coatings, increased production of aqueous printing inks, and high-solid versions of adhesives and sealants. While these trends will lead to outright declines for many traditional solvent products, they will also create opportunities for alternative products. Many of these alternatives, such as propylene glycol, terpenes and hydrogen peroxide, are green solvents. However, some conventional solvents, namely alcohols (ethanol in particular) and esters will also register gains.

In overview, some localized pressure exists on the hydrocarbon solvent markets. However, if all the F-T kerosene of Shell's Bintulu plant capacity were to be converted into solvents, it would only fill 1% of the solvent market. Price wise, the projected 12.5 billion pounds in 2010, valued at U.S. $4.4 billion, convert in an average price of U.S. $90 per barrel. Hence, ample and attractive market opportunities.

5.4.5 F-T Kerosene - Lamp Oil or Heater Oil

The kerosene fraction of the Fischer-Tropsch products has no smell and its smoke point is very high. Therefore, the F-T kerosene is ultimately suitable as lamp oil or as kerosene heater fuel.

The kerosene fraction of the Fischer-Tropsch material produced by the Shell Bintulu plant in Malaysia has been tested as lamp oil for the traditional oil lamps. Depending on the marketing area, this is only a limited volume market; however, as the material is free of odors and does not smoke, it is an attractive blending material for producers of perfumed oils.

While kerosene heaters are primarily used as back-up or emergency heaters in the U.S. and other countries, Japan has proven to be an interesting market. Kerosene heaters are still numerous here and actively used. Tests performed by Shell Japan with pure F-T material led, by the end of 2004, to test marketing of the material in Yokohama and a part of the city of Kamakura in Kanagawa Prefecture. Showa Shell Sekiyu claims in their press release that "the new fuel, made mainly from GTL and synthesized from natural gas, is eco-friendly as it hardly contains sulfur and aromatics. Furthermore, the fuel has beneficial features: it produces no soot even after being burned, has no stinking odors as those emitted from petroleum-based fuels, and it is not very sticky."

5.4.6 F-T Diesel - Drilling Fluids Application

Synthetic based drilling fluids (SBF) are a relatively new class of drilling mud that is particularly useful for deepwater and deviated hole drilling. They were developed to combine the technical advantages of oil-based drilling fluids (OBF) with the low persistence and toxicity of water-based drilling fluids (WBF). In an SBF, the continuous liquid phase is a well-characterized synthetic organic compound. A salt brine is usually dispersed in the synthetic phase to form an emulsion. The other ingredients of an SBF include emulsifiers, barite, clays, lignite, and lime. SBFs contain the same metals as WBFs. All are tightly complexed with the barite and clay fractions of the mud and have a low bioavailability and toxicity. Bulk SBFs are usually not discharged to the ocean. However, due to the environmentally benign character of SBF, drill cuttings generated during drilling with SBFs may be treated to remove SBFs and discharged to the ocean. Drill cuttings contain small amounts of liquid and solid drilling fluid components in addition to formation solids. The cuttings contain a small amount, usually 5 to 15%, adhering SBFs. The SBF base or synthetic fluid may be a hydrocarbon, ether, ester, or acetal. Synthetic hydrocarbons include normal (linear) paraffins (LPs), linear-α-olefins (LAOs), poly-α-olefins (PAOs), and internal olefins (IOs). Most drilling in the Gulf of Mexico currently is with WBFs. When WBFs are not suitable and OBFs are not selected, IO and LAO SBFs were used almost exclusively. Since 1998, when Unocal obtained from the EPA, [39] GTL based synthetic hydrocarbons have been added to these ranks.

The market for synthetic drilling fluid, the C_{17}-C_{22} fraction, from a GTL plant is developed through replacement of the conventional water and diesel-based materials in petroleum exploration and development well drilling. Depending on the complexities of the formations being drilled, the drilling fluid business has transitioned away from traditional Water-Based "Muds" (WBM) and Oil-Based "Muds" (OBM) to a much more complex formulation and chemistry, using Synthetic Based Muds (SBM). As mentioned above, only the contaminated cuttings produced during use of SBM are discharged to the ocean; the drilling mud itself is separated from the cuttings and recycled or regenerated. Therefore, the market for SBMs is based on replacement and new, more complex, drilling ventures. The current spur in (advanced) drilling opens this small market for the F-T hydrocarbons as SBM component even more. Synthetic drilling fluid base materials sell currently (May 2008) at relatively high prices of over U.S. $200 per barrel and hence, represent an attractive market opportunity.

5.4.7 F-T Waxy Raffinate - Base Lube Oils Application

The global lubricant base stock market is moving through a period of rapid change. More stringent finished lubricant performance specifications are driving the demand for higher-quality base oils. These specifications call for:

1. better viscosity grades for increased fuel economy,
2. lower volatility for reduced oil consumption,
3. improved oxidation and thermal stability for longer drain intervals, and
4. improved lubricant performance at low and high temperatures to meet the needs of modern engine designs.

Demand for high-quality base stocks continues to ramp up, and business executives are increasingly challenged to either invest in hydro-cracking and wax isomerization technology or consider exiting the business. The decision is complex, the solution will be costly, and the stakes are high. Adding to the complexity of the decision process is the fact that (GTL) base stocks are a step change in quality and cost.

The Fischer-Tropsch process has the capability of making a waxy raffinate. In general, the C_{23}+ fraction from the F-T process can be used as this base stock in synthetic lubricants. This material, however, is totally different to other refinery waxy raffinate in that it has been hydrogenated and redistilled. It combines extremely high viscosity index with very low Noack volatility and requires only simple dewaxing to make the high performances lubricant blending component or wholly synthetic XHVI lubricating oils. Conventional technology [40] requires the conversion of normally solid hydrocarbons to branched chain normally liquid paraffin hydrocarbons. This is achieved by hydrotreatment and an $AlCl_3$ catalyzed re-arrangement of the wax molecule. We should mention in this respect particularly Shell and Chevron. The latter has developed its hydrofinishing technology that uses noble-metal catalysts rather than base-metal catalysts, called ISOFINISHING. ISOFINISHING particularly improves oxidation stability and color.

Specifications of the various lube oils are:

Group	Saturate Content	Sulfur Content	Viscosity Index
I	90	Equal or > 0.03	80 -120
II	Equal or > 90	Equal or > 0.03	80 -120
III	Equal or > 90	Equal or > 0.03	Equal or > 120
IV		Poly Alpha Olefins	
V		Base oils not included in the above, e.g. esters	

To start with, let us look specifically at where the base stock business is today and where it is likely to go during the next decade. Our focus is specifically on lubricant base stocks used in commercial automotive, consumer automotive, industrial lubrication, process oil, and functional fluid applications. This world lubricants market is large, estimated at some 40 million tons per year of which the majority is Group II quality. In this market, we can identify the forces driving base stock demand from both the perspective of a supply push as well as the composition of the base stock required to satisfy finished-product performance requirements (demand pull). Also we find increasingly alliances between suppliers and major consumers. The latest one is the pact between Suzuki Motor and Shell. [41] On August 19, 2007 Suzuki Motors Corp. (SMC), one of the largest car manufacturers in Japan, announced that it signed a long-term agreement with Shell Petrochemicals and Gas in a move that will see Shell lubricants and oils exclusively used in vehicles manufactured at two Suzuki automotive plants in Kosai and Iwata, Japan. If one then knows that Shell is to be the sole supplier of Motiva Group II base oils in Europe as a long-term supply solution, running parallel with gas-to-liquids base oils in the future, the future for Shell lube oils is clear. [for the reader: Motiva Enterprises LLC, the largest Group II base oils producer in the world, is a joint venture formed in 1998 between Saudi Refining and Shell Oil Company. After a planned expansion at its US Gulf Coast refineries, market sources estimated its total base oils capacity would be around 41,000 bbl/day].

Specifications for finished lubricants are growing more stringent and require the use of higher-performance base stocks. However, the market for this high performance lubricant blending component is concentrated in the areas with high performance engines. The regions of the world that have the greatest impact on the quality of lubricant base stocks used are North America, Western Europe, the Asia-Pacific region and Japan.

This market is estimated to be some 200,000 tons per year and the margins are very attractive. This market is expected to grow by at least 50% over the next decade.

The supply of lubricant base stock material is affected by changes in manufacturing processes, plant closures, capacity additions, and changes in import and export balances. However, the biggest impact on supply is the emergence of GTL base stocks, resulting in exciting business opportunities. The market is currently predominantly supplied by material originating from the (Exxon patented) alpha-olefins. From this material, through polymerization, the Poly Alpha Olefins (PAO) lube oil is obtained. With the venue of F-T material Shell, via SMDS (Malaysia), presently supplies Showa Shell Sekiyu, Japan and Shell Trading and Shipping Co. (STASCO) with volumes of SMDS waxy raffinate from their Bintulu plant. Additional synthetic lube oil will reach the market this year starting with the production from the Sasol ORYX F-T plant in Qatar. The Sasol production, ultimately complemented with the potential capacity of the Shell Pearl, which will produce 140,000 bbl/d of total F-T products, is forecasted to give interesting developments on the lube oil market.

In terms of market values that can be realized for the lubricant bases stocks from GTL, little data are available, as for example Shell supplies its own subsidiaries with the material. Research data suggest that values of U.S. $600–U.S. $1,500 per barrel should be attainable.

Group III-capable refiners include in alphabetical order:

BRITISH PETROLEUM
CHEVRONTEXACO
CONOCOPHILLIPS
EXXONMOBIL CORPORATION
FORTUM
IDEMITSU KOSAN
JAPAN ENERGY
MARATHON-ASHLAND PETROLEUM LLC
MOTIVA ENTERPRISES LLC
NIPPON OIL CORPORATION
PETRO-CANADA LUBRICANTS
SHELL
SHOWA SHELL SEKIYU
SK CORPORATION

5.4.8 Specialty Waxes

The wax market, further divided into animal, vegetable, mineral and now synthetic F-T waxes, is dominated by petroleum wax. The total world paraffin wax consumption is about 4 million tons per annum and has over the last 15 years displayed an average annual growth of little over 4 %.

Important markets for waxes are the USA, the central European countries, the Pacific Basin, Japan and Taiwan, India, Brazil and South Africa. Wax utilization varies significantly in different countries. For example, although globally 40% of the end-use for petroleum waxes is candles, this figure is 70% for South America, slightly more than 25% in Japan and 15% in the USA (while candles account for 7%–8% of the U.S. wax production, some 7% is imported as finished candles). Other examples of the difference in the wax utilization between the USA and Japan include: paper and packaging applications in Japan are less than 45 million pounds, or 21% of consumption. This is much lower than in the U.S. where these uses account for 50%–55 % of the petroleum wax production. Utilization in rubber is the third in importance in Japan at

15%, compared to 4%5% in the USA. The latter is in part due to the high level of tire production in Japan.

Particular wax market growth areas are Asia and Western Europe. In recent years, the market has been constrained by reduction in the production in the CIS; however, this has to an extent been balanced by increasing supply from the Peoples Republic of China. Therefore, and because of its quality, the market has welcomed the roughly 0.2 million tons per annum of SMDS Fischer-Tropsch paraffinic wax, which finds its application in high added value products, mainly in indirect food applications. However, additional F-T complexes, like the ones in Qatar, looking at production of minimally 75,000 bbl/d–100,000 bbl/d of products are predicted not to be able to find such reception in the market. Each of those three complexes to come on stream by 2011 could in principle add 30%–40 % of the existing consumption volume to the market. Hence, these projects are mainly based on transportation fuels and will not influence the wax markets.

The use of wax from the predominantly paraffin market, in terms of applications, is diverse and varies from large industrial volumes for candles, paper & packaging, rubber, and electrical use to various minor outlets in the food and cosmetics sector.

As one can imagine, only little synthetic wax is yet marketed. In general, F-T synthetic waxes can be used in the same applications as petroleum paraffin waxes. The straight run F-T wax fraction has the food grade quality. Therefore, this (soft and hard quality) wax enjoys extensive markets and applications in the specialty chemical industry, pharmaceutical and food applications. The F-T wax utilization in the food and pharmaceutical industry has been covered with FDA certifications. The high linearity and sharp carbon distribution of F-T waxes produce a narrow melt range, making these waxes highly versatile for wax formulators. The product has been applied in the aforementioned industrial applications, and new ones like chewing gum, lipsticks, food quality wax paper, etc. Since their production costs are so competitive, more and more the door is open for the low melting F-T waxes in diverse applications of specialty waxes, butters, and wax bases for the personal care and food marketplaces. Here it serves a diverse range of products for processed and prepared foods, previously based on vegetable and specialty oils. It has been used in non-stick sprays for baking in which high temperature stability and superior release properties are desired as well as process aids for a variety of applications, like emulsifiers, dough conditioners, crumb retardants, flavor and color dispersants, stabilizers, texturizers and binding agents. Particular applications are the use in low-carb foods, low-carb baked goods, and in low-carb salad dressings.

Anecdotically, the Shell F-T wax has been applied for candles with interesting results:

- When the F-T wax was simply used in the candle manufacture, candles were produced which burned up to 30% longer than regular candles. Such is explained by the solid-state properties or polymorphism of the F-T paraffin wax.
- When the F-T wax was applied as outer coating of regular candles, the perfect “non-drip” candle was obtained.

Hence, as candle wax component the F-T wax command extra premium product prices.

FT Wax

Light a candle for FT-wax!

In the Western Hemisphere, Shell Oil Co. is the exclusive F-T wax distributor for the USA and Canada. Shipments of paraffinic SMDS wax have been made to Shell's Deer park Refinery, Texas, since November 1994. Its subsidiary, Equilon Enterprises LLC, offers waxes that are blends of the SMDS products and domestically produced waxes. Moore and Munger is the distributor for Sasol wax in the USA.

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6 ENVIRONMENTAL, WITH A LIMITED DISCUSSON ON PERMITTING

6.1 Summary/Conclusions

The environmental issues of both the GTL process and GTL products are discussed. The GTL process selection is made to minimally impact the local environment. The largest effluent stream is water, which is recycled to the process units to the largest extend possible. Excess water can be used for enhanced oil recovery through oil well water floods. Various adsorbents and catalyst are used in the plant, all of which can be recycled using metal reclaiming and/or metal smelting.

Plant and product specific emissions (CO_2, SO_2, NO_x, CO, hydrocarbons and particulate matter) are individually discussed. It is concluded that the GTL process is on a par, if not better, than refinery systems, in terms of CO_2 emissions, using either the Life Cycle Analysis or the "Well to Wheel" method.

GTL diesel has convincingly demonstrated reductions in tail pipe gas emissions ranging from 8% to 38%. GTL fuels used in concert with new engine technologies will only reduce emissions further.

Regarding the permitting of a GTL plant, this report discusses a preliminary outline of the procedures to be followed, the stakeholders and permitting organization. In overview it is felt that permitting of a potential GTL facility should be feasible within two years, consistent with a plan to start the first phase of construction by 2010.

6.2 Introduction

Within this section, we will examine the various environmental aspects of the total Fischer-Tropsch process. In many cases, people take Fischer-Tropsch products and their benefit to the environment as synonymous. In that context we will discuss the fuel-related benefits. However, the F-T products are the result of a "process," which in itself carries many more environmental aspects. Therefore, we will talk briefly about [1]:

Environmental PROCESS considerations:

- **Air, Solids and Water, and**

Environmental PRODUCT considerations:

- **F-T Transportation Fuels (gasoline, diesel, jet-fuel and naphtha to name four)**

6.3 Environmental Process Considerations

The easiest way to discuss these considerations comprehensively is with the help of some block diagrams. In Section 3 (TECHNOLOGY) we have already stated that for larger GTL facilities the economic benefits of the use of oxygen to make syngas are evident. The use of oxygen also avoids the requirement of availability of plentiful, good quality water, another means to serve as oxidants in the syngas generations process. Finally it should be noted that reformation with oxygen can be done under pressure, hence avoiding syngas compression and also circumvents fuel gas firing, hence, furnace exhaust gases. In general it can be stated that the process selection will be based on the available resources with the aim to impact the environment minimally.

For the case of the North Slope we have therefore selected a particular process configuration for the GTL plant which is depicted in pictures below consisting of: an Auto-Thermal Reformer (ATR)/Steam Methane Reformer (SMR) combination (yellow boxes) to generate the syngas, a low temperature F-T process (LTFT) (blue boxes) and a mild hydro-cracker/distillation section for the product upgrading (green boxes).

This particular scheme with the ATR/steam methane reformer combination is presently in operation in Sasol's ORYX plant in Qatar, while Shell has a similar configuration under construction, albeit that its oxygen blown syngas generator, also called POx unit, operates without catalyst. It illustrates best the environmental aspects of the most likely processes for the Alaska North Slope. Different process configurations, however, are also in use:

PetroSA uses SMR (Combi-forming)-High Temperature F-T (HTFT), LTFT and distillation

Sasol uses ATR, both HTFT and LTFT and distillation in Sasolburg, SA

Sasol uses coal gasification-HTFT and distillation in Secunda, SA

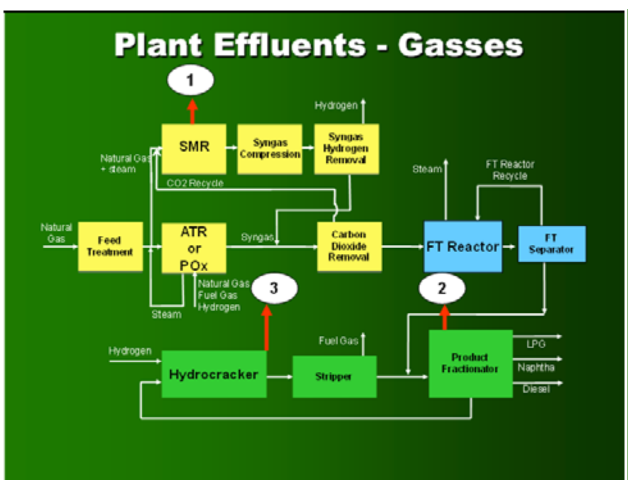
Sasol uses ATR, LTFT and distillation in the ORYX plant in Qatar

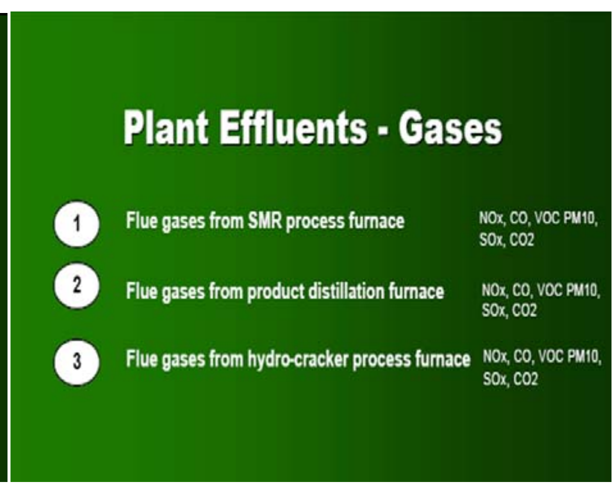
Shell uses partial oxidation (POx)-LTFT- mild hydro-cracker/distillation.

At this point is might be helpful to discuss the experiences with the above configurations. The most extensive experience in the world with the production of synthetic fuels lays with Sasol in South Africa. Sasol has been operating F-T-based synthetic fuel plants since 1955, albeit on coal. The syngas generator is in their case called a gasifier, since the particular syngas generator converts a solid feed stream into a gaseous product stream (also, if oil or heavy residue were to be used to generate syngas we would speak of a gasifier). The conversion of natural gas with oxygen to syngas is of more recent date and has only been practiced since the 1970s initially in methanol plants, and later, when conversion of remotely-located, "stranded gas" was initiated. In the latter case both PetroSA (as of 1992) and Shell (as of 1993) have almost the same length of experiences

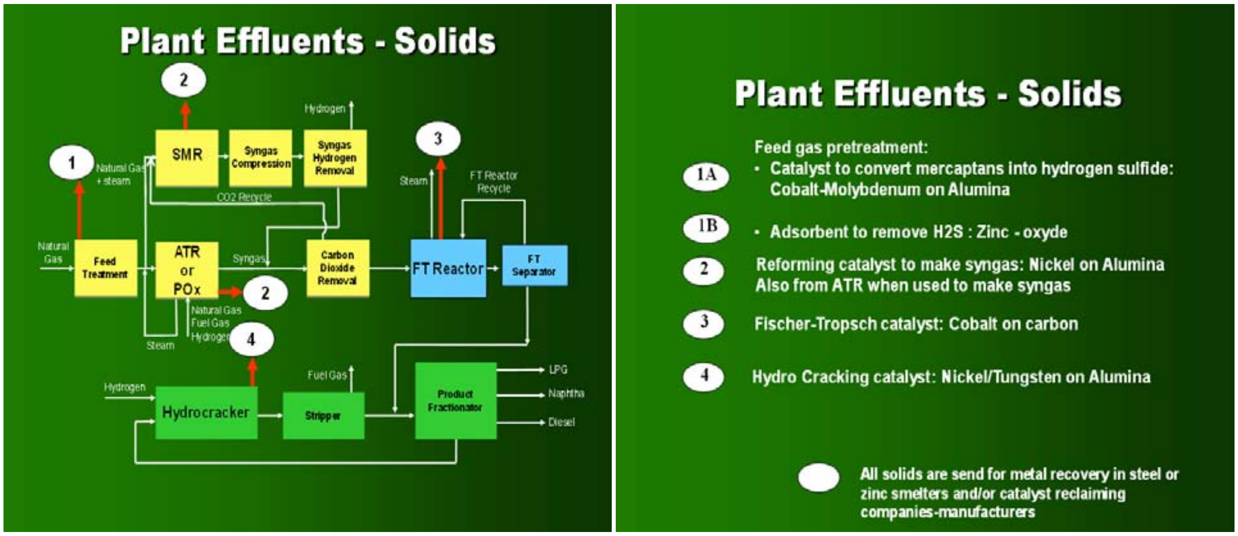
In the GTL process diagram, the white ovals are indicative of the sources of emissions borne by, or in the form of gases, solids and water. The accompanying table presents the effluent constituents one would typically expect. It is obviously not the purpose of this study to present a complete mass-, heat- and effluent balance of a F-T plant, neither to give quantitative data on the emissions, but rather to qualitatively indicate the sources. We will also indicate how the various emissions are typically mitigated. In general it is fair to state that GTL companies have come to build plants that are fully acceptable in their environment, as well as that they have come to the realization that every stream out of the plant is a "PRODUCT" stream. In that light they see a CO_2 stream as a resource bearing carbon molecules and a water stream as potential process water, for water flooding (EOR) or as an irrigation source. We hope that the schematics are self-explanatory and helpful in understanding the source and origins of the potential emissions.

The gaseous or airborne emissions in the schematic below are obviously related to the fired equipment in the plant: the SMR, a furnace for the distillation and one for the hydro-cracker. Obviously, while creating a clean new energy source for others, energy conservation and emissions minimization received the highest attention in a GTL plant. A GTL plant therefore includes a fully integrated network of heat recovery systems, so as to minimize the use of furnaces and emissions. Since the emission products of the various pieces of fired equipment in the plant are similar to those of the F-T products, these will be discussed under the F-T-product section of this section. The GTL plant handles, as process streams, natural gas, syngas (CO and H_2), carbon dioxide and hydrogen, all of which are valuable process components. For this, but also for safety reasons, they are therefore closely contained by tight leak control scheme involving flange leak testing and gas monitors.





The potential sources of emissions by solids are all related to catalysts and adsorbents. In general, all catalysts are of sufficient value to be routed back to the original manufacturer or other facility for metal reclaiming. Also, in case reclaiming is not economically attractive for the catalyst, it is common that the steel industry will find enough value in the metals to accept them (or sometimes buy them) for upgrading of various steels. In these cases the catalysts are melted with steel to produce higher quality materials, e.g. stainless steels.



Finally, we'll address the water effluent side of the process:

Water effluents (and therewith the potential of the coinciding emissions) are very important in the F-T process. The reader will remember from the GTL process section, that in the GTL process volumetrically as much water is produced as hydrocarbons. From the basic equitation of reaction:

$$2(n+0.5)\ H_2 + 2nCO \rightarrow \Sigma C_nH_{2n} + \Sigma C_nH_{2n+2} + 2nH_2O$$

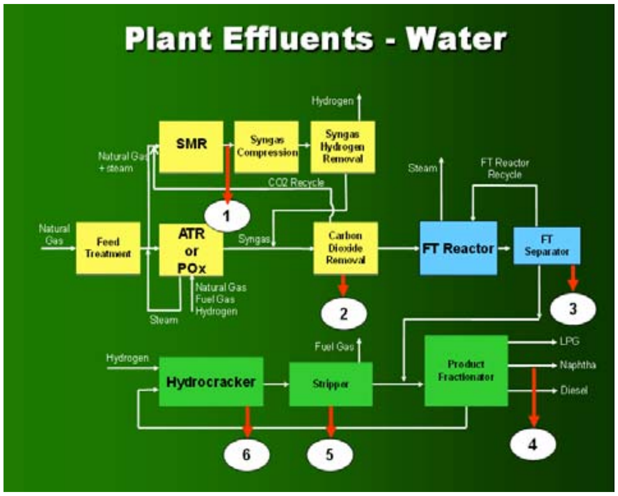
Thus it follows that for every mole of carbon monoxide converted a mole of water is produced.

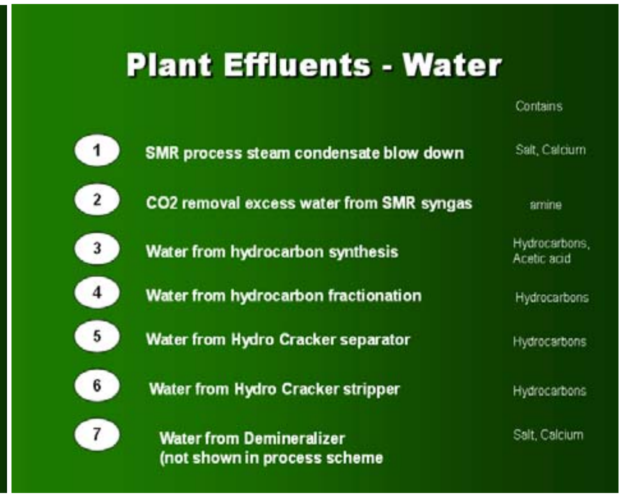
Thus, depending on how the carbon monoxide is generated, the fully integrated GTL process is either a water producer, if using oxygen, or (minor) water consumer, if using steam.

When an external oxygen source, like an air separation unit or oxygen plant, is used in the generation of synthesis gas from natural gas, the facility is a net water producer. Such is the case for the Mossgas and Shell Bintulu plants. In the case of a scheme, based on pure steam methane reforming, water is the vehicle through which oxygen is circulated in the plant.

A GTL plant is, in the Fischer-Tropsch part of the plant, also a (minor) water consumer since very small quantities of oxygenates form in the synthesis process. The types of oxygenate formed include many of the lower aldehydes, alcohols and acids. Depending on the F-T catalyst composition, there may be a peak in concentration in acetic acid. The latter concentration in the reactor effluent water may reach the 1%–2% range. The reactor water is generally stripped from dissolved gases, hydrocarbons and acids by steam stripping. The water is then, as far as needed, ready for reutilization in the process plant.

Hence, good housekeeping with water flows, stream segregation and water re-utilization are essential in the process. Having this under control, it turns out that the main source of discharge is a stream of impurities, generated while, in the case of Alaska North Slope GTL, cleaning up seawater to drinking water quality and ultimately to boiler feed-water quality. Such requires complete desalination or demineralization and thus, disposal of naturally occurring salts, albeit in more concentrated form. This effluent stream is part of the plant's utility center.





Hence it is not shown in the process flow diagram, but given in the table as stream number 7 above.

Water Synergies

Wastewater leaving the plant can be treated in a separator for entrained hydrocarbons removal. Sometimes, a Parallel Plate Interceptor (PPI) or Corrugated Plate Interceptor (CPI) is used for such service; further treatment follows in a flotation/flocculation unit to remove any suspended solids, and in a bio-treater to allow its discharge as surface water. As a principle, process water and condensates are re-used to minimize discharge. When an oxygen-blown gasification scheme is involved, the F-T process is a net producer of water. Such opens up another interesting aspect of the process: in arid areas, the water effluent may be used for irrigation purposes after cleanup; it can be applied directly to growing crops. It is the understanding that such schemes are being used in the newly commissioned or planned GTL installations in Qatar. In other cases water can serve as source for secondary oil recovery by water flooding. Since the water from the GTL process is chemically derived, it contains no minerals, like sea water does. It lends itself therefore eminently as use in gel-based chemically enhanced oil recovery. Gel formulations are tailored to oil bearing reservoir characteristics, but they need clean (fresh) water. Such application, utilization of the gels by one U.S. company, have resulted in the production of more than 50 million barrels of incremental oil from North American reservoirs alone.[2] With the possible availability of clean water from a GTL plant such may well be considered on the North Slope.

6.4 Environmental Product Considerations

This part will address the use of the F-T products as transportation fuels and its impact on the environment, which, based on the excellent product properties, is superior than offered by current alternatives including petroleum (crude oil) based transportation fuels. In many countries, notably in Europe and the USA, there is legislation that is aimed at limiting particulate and sulfur dioxide emissions that originate from the combustion of transportation fuels by restricting their aromatics and sulfur levels. It is obvious that because the F-T products are intrinsically free from sulfur and aromatics, F-T transportation fuels (naphtha, kerosene and diesel) will definitely meet more stringent requirements. However, requirements and its enforcement is, with time, a moving target. Particularly with the increasing concern about global warming, **Green-House Gas (GHG)** emissions receive much attention. Therefore, we begin this part of the section on environmental aspects of the F-T process and products with the discussion of carbon-dioxide emissions.

6.4.1 Carbon-Dioxide Emissions

Most recent, for the USA, the Supreme Court opened the potential for the Environmental Protection Agency (EPA) to regulate carbon dioxide. In ruling No. 05–1120 [3] (argued November 29, 2006, decided April 2, 2007), the United States Supreme Court ruled 5 to 4 that carbon dioxide and other greenhouse gases are pollutants under the *Clean Air Act* and that the EPA does possess the authority to regulate these emissions. The court's ruling continued in saying the EPA's "laundry list" of reasons for declining to regulate emissions was simply insufficient and that the Agency should justify its inaction on global warming. This was the Court's first case on climate change. Seemingly, the decision supports the 11 States that are trying to gain EPA approval to limit tailpipe CO_2 emissions. Theoretically, this could eventually lead to more fuel-efficient vehicles. Further, the decision now allows greenhouse gas emissions to be capped under federal law. The EPA was not directed by the Court to regulate emissions, but if they decide to, they could limit emissions of all major emitters.

Just having written that "the EPA was not directed by the Court" on May 14, 2007, President Bush directed the Department Of Energy, the U.S. EPA, and the US Department of Transportation to take the first steps toward regulations that would cut greenhouse gas emissions from motor vehicles. The President issued an executive order setting a new policy for the three agencies to work together to protect the environment from GHGs emitted by engines and to do so in a manner consistent with sound science, public safety, economic growth, and an analysis of costs and benefits. The order directs the three federal agencies to prepare regulations for motor vehicles, non-road vehicles, and non-road engines that achieve this policy to the maximum extent permitted by law and considered practical by the three agencies. The order also directs the agencies to consult with the Secretary of Agriculture whenever a regulatory action will have a significant effect on crops related to the production of renewable fuels, such as ethanol or bio-diesel. For the full executive order, see reference.[4]

In announcing the new policy, President Bush said he was spurred by a Supreme Court ruling that the EPA must take action under the *Clean Air Act* to regulate GHG emissions from motor vehicles. In a meeting with leaders from the four agencies, the President asked the agencies to start with his "20-in-10" goal of reducing gasoline use by 20% over the next 10 years. President Bush set the end of 2008 as a deadline for the new regulations, and also called on Congress to support the regulations with appropriate legislation.

The USA has therefore opened the door to a practice already established in Europe. Under the understanding that methane, carbon dioxide and nitrous oxide are the principal greenhouse gases, the Europeans have singled out CO_2 as the main culprit in global warming. In Britain, the Labor Government has put at the heart of its transport policy the principle that "the polluter pays." This means the UK's 30 million motorists now pay their annual road tax based on a sliding scale of zero to £215—depending on how much CO_2 their vehicle emits. Tax on company cars is also now linked to CO_2 emissions, and ministers have told councils that toll road pricing should also take this into account.

As mentioned above, such CO_2 taxes could eventually lead to more fuel-efficient vehicles. Let us give the reader a little taste of this, as manufacturers are fighting to show off a new generation of lean, mean, "green" machines that customers will actually want to buy. At the 77th International Motor Show in Geneva, March 8–18, 2007, [5] the top marks went to the small but perfectly formed Honda hybrid sports car prototype, a Japanese gasoline-electric low-emissions vehicle designed to show that saving the planet can also be fun. The futuristic two-seater delivers 60 miles to the gallon, and is aimed at customers who want an alternative to gas-guzzlers without being branded dull and boring. The Honda sports car looks unmistakably like a racer, but is powered by a 1.4-litre four-cylinder gasoline-electric "hybrid" system, which gives it a top speed of more than 120mph. Yet it emits only 120g/km of CO_2, putting it in the second lowest road tax bracket for the UK, which means owners will shell out £40 a year for a road license.

The car manufacturers, particularly the Japanese and European ones, are striving to those lean, mean, "green" vehicles. It is there where diesel engines and GTL ultimately come together with the best tail pipe emissions. The latest one [6] is the new edgy, four-wheel drive, Mercedes GLK, revealed at the April 2008 Beijing Motor Show, before going on sale across Europe in October. It is the diesels that are expected to account for the majority of sales. Among them is Mercedes-Benz's new 170bhp, 2.1-litre, four-cylinder, common-rail diesel in the entry-level GLK220 CDI BlueEfficiency. With 295lb ft of torque, it is claimed to hit 62mph in 8.8sec and reach a top speed of 127mph, while averaging 40.9 mpg and emitting, with regular crude oil-based diesel, 183g/km of CO2. Mercedes-Benz hinted at a hybrid version of its new off-roader that mates the

GLK BlueEfficiency's 2.1-litre diesel with an electric motor for combined total of 224bhp and 413lb ft. That's sufficient, it says, for 0-62mph in 7.3sec, a 134mph top speed, 47.7mpg and 157g/km (crude oil diesel fuel basis). One can only imagine how these new generation vehicles running on GTL diesel can change the tail pipe emissions.

If we understand methane, carbon dioxide and nitrous oxide to be the principal greenhouse gases, the GTL process can both be considered as GHG consumer as well as producer. In this discussion, the GTL distillates are often compared to crude oil derived diesel when a "Well to Wheel" or "Life Cycle Assessment (LCA)" analysis is done.

The two are, however, completely different in their approach and should not be confused. The results of the two approaches are not comparable, since they study two fundamentally different systems. We will take a moment here to discuss this in detail and thereafter present some of the available material:

"Well to Wheel" studies utilize an allocation approach. Allocation is creating a "virtual" product assessment by eliminating all co- and by-products for the assessment. Allocation uses physical (such as mass or heating value ratios) or in some cases financial properties of co-products to isolate individual product flows out of a more comprehensive system. For example, "Well-to-Wheel" studies concentrate solely on transportation fuels. Where a system (such as conventional refining or GTL) produces other products in addition to transportation fuels, these other products are not considered. Those other products are eliminated from the system by using physical relationships of the co-products and only accounting for the percentage share of the product of interest. If, for example, a process produces two products A and B, of which only A is required, the mass ratio between A and B is used to determine how much respective burden the individual products have to carry from the process input and the additional upstream loads. Assessments that use such an approach compare the environmental inputs and outputs, and associated environmental impacts of transportation fuel only. The underlying question may be formulated as: "How does the environmental performance of fuel X compare with fuel Y from 'Well to Wheel'?"

In Life Cycle Assessment (LCA) studies, a system expansion approach is being utilized. LCA is an internationally agreed methodology for system-wide environmental assessments and offers a holistic view of the environmental impacts of products or technologies by considering impacts throughout the value chain under study. The system expansion approach takes a more comprehensive view and seeks to ask the question, "What are the environmental implications of supplying markets 1, 2, 3 with products from technologies A, B and C?" To answer this question, it is necessary to consider the entire technology system. Specifically for the GTL technology, a system comparison for a complex refinery system would include refining the main products and markets. Refineries produce transportation fuels and a range of other higher value products not to mention "waste heat" used to produce power for both on and off site consumption. Those products supply markets globally and, in turn, produce their own environmental impacts across the supply chain. A decision to build a new refinery is a decision to supply a number of products to a range of markets, not just transportation fuel. The LCA study results provide a holistic view of how the technologies impact the environment by measuring impacts caused by producing, transporting and using the fuels.

There have been many "Well to Wheel" and LCA studies done. Here we will discuss the Five Winds International report [7], which presents the environmental attributes of GTL fuel or diesel based on the results of three independent studies that compared GTL technologies to conventional refinery-based technologies. These studies are the ConocoPhillips study, prepared by Nexant, 2003; the Sasol Chevron study, prepared by PricewaterhouseCoopers LLP (PwC), November 2002; and the Shell study, also prepared by PwC, May 2003. The LCA studies underlying this report have been performed in accordance with the internationally accepted standards for LCA. For each study, a third party critical review process ensured compatibility with these standards, including consistency between the studies and their stated goals. LCA is internationally accepted, recognized and endorsed by the European Commission's work on Integrated Product Policy and the United Nations in proceedings of the World Summit in Johannesburg.

The three LCA studies are based on the ISO 14040 series of standards of the International Standardization Organization (ISO). The standards provide detailed guidelines for performing LCA studies by establishing a consensus approach, while still allowing flexibility; however, individual analysts may still interpret or modify the 14040 approaches into more specific methods or, at the next level, into their specific tools or software. Focus in the standard is on preventing misuse of LCA. While each study differs with respect to technology, scope, sources of data and boundary conditions, the studies' findings do indicate similar overall trends. The key findings of the report include:

1) Greenhouse Gas performance goals

Production and use of GTL fuel can contribute less greenhouse gas to the atmosphere than production and use of conventional diesel fuel. The study commissioned by ConocoPhillips indicates that the reduction in greenhouse gas emissions is significant if the GTL fuel is produced from associated gas that is otherwise flared in amounts of 10% or greater. More conservatively, and in cases where the feedstock is from other sources, the greenhouse gas contribution of GTL fuels is comparable to conventional diesel technology. While the GHG emissions from production and upstream processes of the GTL system are higher compared to the refinery-based system, the advantages in the product utilization phase, at a minimum, compensate for the earlier disadvantages.

2) Protecting & extending resource availability

Fueling vehicles with GTL fuel consumes fewer petroleum resources per distance traveled than with conventional diesel. In addition, the study commissioned by ConocoPhillips indicated that given forecasts of the rate of development of stranded gas projects, GTL fuel production will continue after crude oil reserves are depleted based on today's assessment of the life span of crude oil reserves. This is because GTL technology exploits remote gas reserves and not crude oil. Extrapolating from this point, using remote gas to create GTL fuel will extend the lifetime of crude oil reserves accordingly.

However, producing GTL fuel currently requires more energy and resources per unit mass produced than conventional diesel production. Improvements with respect to thermal efficiency in the GTL system can be expected over time since the technology has not gone through the same degree of technological improvement as the conventional crude oil refinery system. For both the production of GTL fuel and across the full life cycle, GTL requires fewer petroleum resources than conventional diesel production. This is because the utilization of remote and otherwise unutilized gas reserves extends the availability of known crude oil reserves by providing an alternative source for transportation fuels. It also contributes to an enhanced diversity and security in supply.

3) Reliability of feedstock supplies for fuel

Natural gas is the cleanest fossil fuel. There is potential for remote natural gas to provide energy to the global market for many decades. With respect to environmental impacts, remote natural gas can provide this energy in a manner comparable or better than petroleum reserves.

4) Air quality in urban centers

GTL fuels are virtually free of sulfur and aromatics. Per distance traveled, GTL fuels contribute fewer emissions and negative impacts on urban air quality than conventional diesel. According to the studies, GTL technology creates fewer air pollutants (SO_2, NOx, VOCs and particulate emissions) and thus contributes less to acidification of the air and formation of smog. Although the results of each of the studies are somewhat different, it appears that there are fewer environmental and health impacts from GTL fuel than from conventional petroleum based diesel.

5) Air acidification

With significantly lower emissions of acidifying gases, GTL technology potentially causes less air acidification than the conventional diesel technology. While the emissions from GTL are lower, there is no direct link between the amount of emissions and actual acidification because actual acidification depends so heavily on factors specific to the environment where the emissions are received (such as climate, soils, geology, etc.).

6) GTL Technology can be used without new capital and infrastructure

GTL fuel can be used either directly or blended with conventional diesel and burned in conventional diesel-powered vehicles. Tanks, pumps and other fuelling infrastructure can be filled with GTL fuel without significant retrofitting or capital investment. While there is potential to optimize vehicle engines to run even more efficiently on GTL fuel, such re-design is not essential. Technological advances in design of advanced engines can be a longer-term goal consistent with the growth of GTL markets.

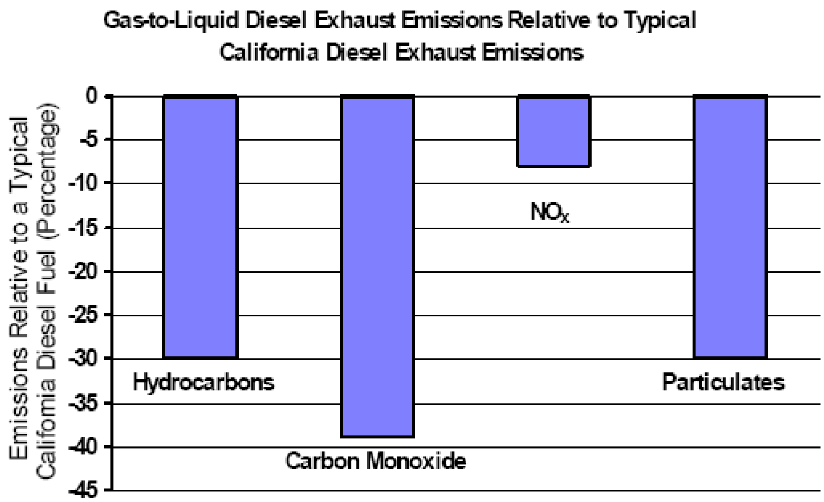
7) Waste reduction

The Shell and ConocoPhillips studies indicated that the GTL system generates less solid waste (up to 40% less according to the Shell study) and less hazardous waste than conventional crude oil refining technologies.

Emissions of hydrocarbon products are, with the exception of sulfur, not explicitly covered under industry standards like the ASTM method series. With the exception of particulate matter, the emissions or emitted species are measured by gas chromatograph. They are expressed as unit weight or volume per volume of exhaust gas. In the following, we will endeavor to address the various aspects of emissions. The following currently regulated emissions are to be distinguished:

Sulfurous oxide emissions
Carbon Monoxide emissions
Hydrocarbon emissions
Nitrogen Oxides emission
Particulate emissions

One can show from the literature given in the references below that the Fischer-Tropsch diesel fuel—the predominant component of the low temperature F-T process—and increasing bulk volume of the material, which after 2011 will come on the market, has a consistent benefit in terms of emissions.



(Ref: Southwest Research Institute [8], CEC [9])

SasolChevron has published excellent material on the subject of F-T diesel fuel emissions. [10]

6.4.2 Sulfurous Oxides

Typical emissions of **Sulfurous Oxides** (SO_2) of any combustion process are linear with the amount of sulfur offered to the process, whether it is an internal combustion engine, turbine combustor or the like. From the foregoing sections we know that the F-T catalyst is sensitive to sulfur. Therefore, sulfur components in the synthesis gas are reduced to low levels in the preparation of the feed gas. In addition, the F-T catalyst is probably the best sulfur scavenger in the process. It will tolerate sulfur at parts per billion (ppb) levels. Higher sulfur contents than 30 ppb in the feed to the F-T catalyst will seriously limit the cobalt catalyst life (iron will tolerate little more than cobalt—very low ppm level rather than ppb level). As a result, the pure F-T products are virtually sulfur-free. However, in all processing schemes a hydro-cracker is involved. The latter might use sulfided hydro-cracking catalysts, which introduces another source of sulfur.

Let us reiterate the effects of sulfur compounds. They can be corrosive, can affect exhaust emissions from engines, can damage or impede the operation of emission control devices, and can increase secondary pollutant formation in the atmosphere. An often forgotten effect of sulfur in fuel is its capacity to provide lubrication inherent to the fuel. The allowable sulfur content, expressed as percentage by weight of elemental sulfur and not as percentage of sulfur compounds, is limited by specifications. ASTM D 3120 has been developed to determine this. F-T-based fuel is compatible with future exhaust gas after treatment technologies that may be sensitive to fuel sulfur content, such as auto-catalysts and particulate traps. As we have shown, with the literature available on hand, the reduction of emissions of sulfurous oxides, which can be achieved with F-T-based fuels, is directly linear to the amount of F-T material blended in the fuel.

6.4.3 Carbon Monoxide

Emissions of **Carbon Monoxide** (CO) are harmful to the environment as carbon monoxide is a poisonous, colorless and odorless gas. Contrary to sulfurous oxide, one **can't smell it, see it or taste it.** Carbon monoxide links 250 times more strongly to hemoglobin than oxygen. With increased carbon monoxide concentrations in inhaled air, this suppression of oxygen leads to suffocation symptoms through to death. Acute poisoning occurs beyond 2,000 ppm, sub acute at just 500 ppm CO. The guideline for the Maximal Workplace Concentration (German MAK Value) is 35 mg/m^3 (MAK List, 2004). ***Carbon monoxide is the result of the incomplete combustion of fuels***. In addition to combustion in engines, household and industrial combustion processes, the oxidation of methane in the troposphere as well as the decomposition of chlorophyll can be named as sources of emissions. CO is constantly oxidized to CO_2 in the atmosphere or eliminated by soil bacteria. The average residence time in the troposphere is less than half a year. Through the high conversion of CO in the atmosphere the main danger is less at the global level than at the local level, and particularly in closed rooms. Carbon monoxide is one of the most toxic substances we come into contact with in confined spaces in our daily life, in our home, at work, garage, car, recreational vehicle and boat**.** There are hundreds of fatalities every year from carbon monoxide, and just a small amount of carbon monoxide in our living area can cause major problems over time. While the overall dosing of oxygen or air to a combustion process can be fully satisfactory, the combustion mixture is rarely homogeneous, so that pockets of fuel/oxygen mixtures, which are very carbon rich, can still exist. Typical examples of carbon-rich fuels are the so-called aromatic fuels, containing molecular ring structures. F-T fuels are hydrogen rich, purely linear, paraffins, with no possibility to contain excess carbon. Therefore, we will see a more perfect combustion with fuels containing F-T products. Overall reductions of CO emissions compared to regular crude oil derived fuels are in the order of 30% to 40%.

6.4.4 Hydrocarbons

Hydrocarbon emissions (HC) in the exhaust gases of combustion processes are similarly an indication of a less perfect combustion process. Too much fuel components/too little oxygen will result in depletion of the oxidant, which even on a local basis leads to remaining hydrocarbons in the exhaust gases. Fuel volatility, viscosity and homogeneity also play a role in this process. Thanks to the consistent paraffinic, and hence, almost homogenous composition of F-T material, fuels containing F-T products have been observed to enjoy reductions in hydrocarbon emission of 45% to 55%, when compared to conventional crude oil based fuels. This applies to a lesser extend for CNG and LNG as the homogeneity of the fuels improves in the order – liquid petroleum fuel, CNG, LNG. Also the miscibility of a gaseous fuel with combustion air is better than a (partial) vaporized liquid fuel/air mixture.

One disturbing fact in the determination of hydrocarbons in exhaust gases is that, contrary to Europe, in the USA methane is exempt from the hydrocarbon measurement. Hence, LNG and CNG vehicles can emit unburned fuel that has much more impact on Green House Gases (GHG) emissions (as methane is 30 times more problematic than CO_2), without breaking the law. Also, although not part of this report, methane emissions from solid waste sites could account for more GHG emission impact than vehicles on the road.

6.4.5 Nitrogen-Oxides

Nitrogen-Oxides (NOx) emissions are a completely different issue. Nitrogen monoxide (NO) and nitrogen dioxide (NO_2) are, in contrast to CO and HC, by-products of complete combustion. Since air is our primary source of oxygen for combustion, nitrogen (being present in air with some 80% volume) is always present and part of the combustion process. Since there are no conventional combustion processes, which take place with guaranteed 100% pure oxygen, one can safely state that all combustion and/or (partial) oxidation processes have nitrogen as a potential reactant. Nitrogen monoxide results as so-called "thermal NO" in the oxygen-rich parts of the flame of the combustion process. Fortunately, nitrogen is not very reactive and requires high temperatures to get activated. The formation of active nitrogen species in combustion and/or partial oxidation processes is thus a distinct function of the (local) combustion temperature in the process. It is self-explanatory that nitrogen, present in the fuel in whatever chemical form, is the second source of nitrogen reactants.

In a combustor, some of the nitrogen will be oxidized. When fully reacted it will take the form of NO_2; partially reacted it will be present as NO. In the partial oxidation process, which is a reducing environment, the nitrogen will take the form of ammonia. In the following, we will concentrate on the common oxidative combustors.

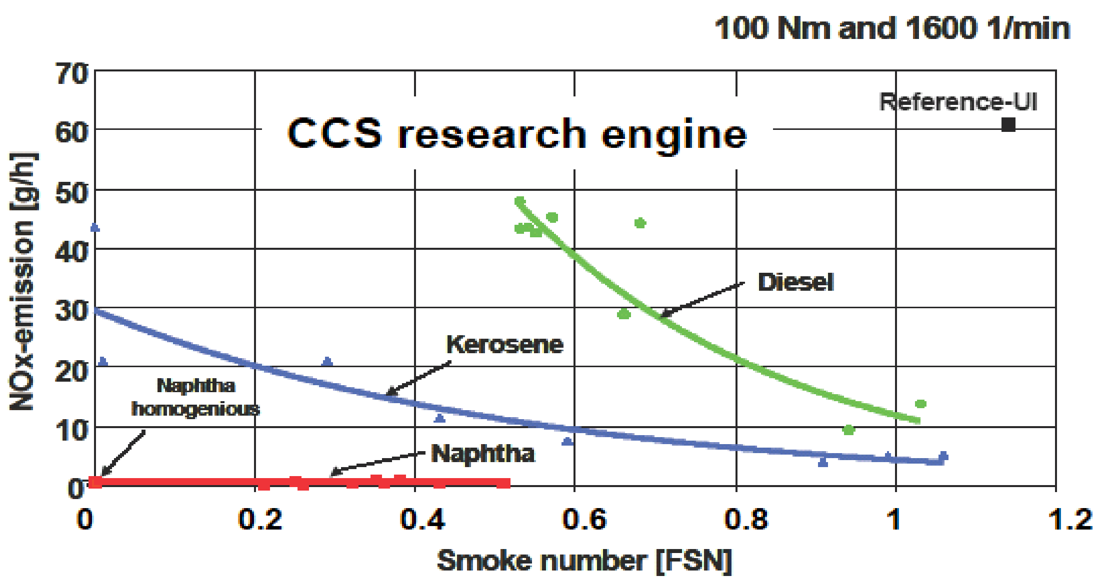
The F-T products have consistently shown that reductions of some 5% to 20% in nitrogen oxides can be obtained. This is due to two effects: the lower nitrogen content of the fuel **and** the lower combustion temperature.

Hence, since F-T products, synthesized from pure CO and hydrogen, do not contain any intrinsic nitrogen, the exhaust gasses of combustors where F-T containing fuel is used will show a reduced nitrogen oxide content when compared to conventional fuels burned. In the abundant nitrogen environment of the combustion process, the influence of the lower content of nitrogen in the hydrocarbon fuel will obviously be small. Hence, we can understand the relatively low numbers of the reduction. Also, it is well known that high NOx emissions are directly related to high adiabatic flame temperatures, which are higher for aromatics.[11] This combustion flame temperature is, in a compression ignition engine, closely related to the cylinder pressure. At optimum injection timing (maximum combustion efficiency), NOx limits are generally exceeded; therefore, the engine is "tuned," i.e. the injection is retarded in order to reduce peak cylinder pressures to bring NOx emissions back within limits. Given the high cetane number of F-T diesel, the ignition delay period can be shorter than with conventional diesel. Therefore, less fuel undergoes premixed combustion and more undergoes mixing-controlled combustion, which advances engine combustion efficiency and thereby improves emissions. As a result of the lower density of a GTL diesel, a longer injection period is required to meet the fuel energy demand of the engine, providing more time for cooling by heat transfer. This not only improves the engine fuel efficiency, it also results in lower cylinder peak pressure and temperature, as compared to conventional diesel. Such also explains the lower NOx formation rates with GTL diesel.

Since homogeneity of the combustion mix, and hence, the type of combustor still play a role we see a spread in the reduction. For light-duty (passenger vehicles), these numbers are on the higher side of the scale, while for the commercial heavy-duty vehicles they are at the middle to lower end. [12] [13] [14] [15]

To underpin the aforementioned, let us note that Volkswagen has already unveiled what it claims is the internal combustion engine of the future. Called the Combined Combustion System (or CCS), it mixes the most favorable characteristics of both gasoline and diesel technology to make one low emission, high-efficiency power unit that runs on synthetic fuel. Mounted in the nose of the recently face-lifted Touran, the engine was introduced to the auto industry press [16] on December 15, 2006.

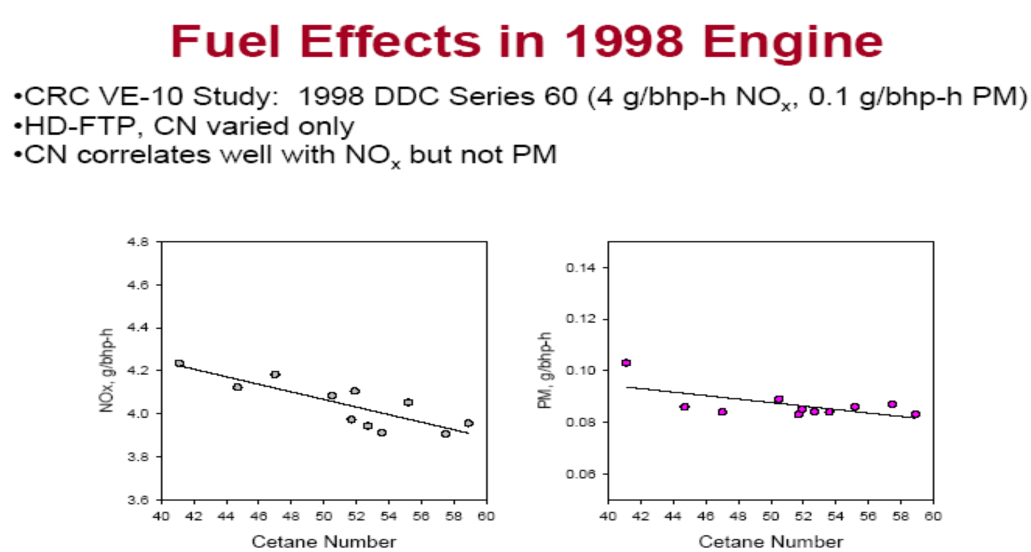
The CCS engine recognizes the possibility that in order to meet tightening emissions standards and ever-higher demands for fuel efficiency, carmakers may have to abandon conventional gasoline and diesel engines in favor of a new type of motor altogether. VW's take on this engine of the future is an advanced four-cylinder based on the German carmaker's upcoming 2.0-litre common rail diesel engine due for production in 2008. It was designed to blend the homogeneous combustion and low nitrous oxide emissions of a typical small capacity gasoline engine with the self-ignition and low fuel consumption properties of a modern day diesel—the aim being to combine the best attributes of each. Using the latest piezo injector technology from German electronics specialist Bosch, the CCS engine is able to begin the combustion process within each cylinder much earlier than in existing diesels, which tend to start shortly after the piston reaches top dead centre. The fuel mixture that enters each of the CCS' cylinders is fully vaporized and ignites over a larger area than it might in a conventional engine, in much the same way as a modern day direct injection gasoline engine does. This early firing reduces the buildup of nitrous oxide and particulates caused by non-vaporized fuel and hot spots within the cylinder—both big drawbacks of today's diesel engines according to Volkswagen. The following NOx emission characteristics were presented:



6.4. Particulate Matter

In a compression ignition engine, **Particulate Matter (PM)** comprises components such as elemental carbon, unburned hydrocarbons, metals and ammonium sulfates and even bound water. According to the definition of the Environmental Protection Agency (EPA) in the USA, particles shall be understood in the following as all substances present in diluted exhaust in solid or liquid form at a temperature of under 51.7° C (meaning 125° F) and that can be deposited on a filter (Code of Federal Regulations). The exhaust gas sample temperature is limited to ensure that all organic compounds with higher boiling points that could be of concern for health reasons and that could be adsorbed on carbon particulate matter are documented by the analysis. The temperature reduction of the exhaust gas samples is achieved by mixing the exhaust gas with air in a dilution system. In this manner, the exit of the exhaust gas into the environment is simulated. The formation of particulates is a complicated process, where sub-stoichiometric combustion and chemical condensation processes play a role. The emitted particle mass consists of a multiplicity of organic and inorganic substances.

Features of F-T diesel, like decreased sulfur, low aromaticity and increased cetane number, thus all contribute to decreased vehicle particulate emissions. The reduced PM emissions characteristic of the F-T diesel fuel is sometimes attributed to the absence of poly-aromatics, which are known PM precursors. The PM is measured by filtering the exhaust gas and weighing the filter. Distinction is often made in the minimum particle size captured. PM50 and PM20 are used to express the threshold of particles of 50 or 20 micron meters (μm), respectively. The concern here is potential shifting of the particle size distribution in combustion processes and the health effects of larger quantities of smaller particles. While reduction levels vary with the type of engine, the cycle tested and the reference test fuel, work done with F-T diesel indicates that particulate reductions of 35% to 60% can be obtained. However, contrary to the linear blending rule, being applicable to the other fuel characteristics, it appears that the combustion process is un-proportionally influenced. There is a general trend indicating that the addition of only limited amounts of F-T diesel to conventional diesel achieves the majority of the emission reduction, with the exception of the sulfurous oxides emissions. Thereafter the "law of diminishing returns" seems to prevail: the more one adds, the lesser the effect. Reductions of up to 70% in particulate emissions were found in blends with only 20% F-T material, while pure (10%) F-T material would give a 78% reduction. [17] [18] [19] [20]



Source: NREL [21]

6.5. The Proof of the Pudding is in the Eating

When it comes to action in the USA regarding environmental matters everyone will agree that California is at the head of the pack. We already elucidated on California's measures to lower the aromatics content and sulfur in diesel. The concern over the GHG emissions has recently led to the California's Governor Schwarzenegger's Executive Order S-1-07, the Low Carbon Fuel Standard (LCFS) (January 18, 2007) [22], which calls for a reduction of at least 10% in the carbon intensity of California's transportation fuels by 2020. It instructed the Secretary of the California Environmental Protection Agency to coordinate activities between the University of California and various state agencies to develop and propose a draft compliance schedule to meet the 2020 Target. This makes California an ultimate target for the hydrogen-rich, low carbon GTL fuel from the North Slope.

Elsewhere the "proof of the pudding" is already demonstrated. In Europe, the authorities, oil- and automotive industry have come together early on. One of the bodies formed was CONCAWE. CONCAWE have been on the forefront of the auto-oil industry impact on the environment: environmental reporting, water quality and PM-matter are just few of the issues addressed by them. For more detail we refer you to the CONCAWE's Internet site [23].

To go further with the synthetic fuels promotion, the Europeans have also formed the "**Alliance for Synthetic Fuels in Europe.**" [24]

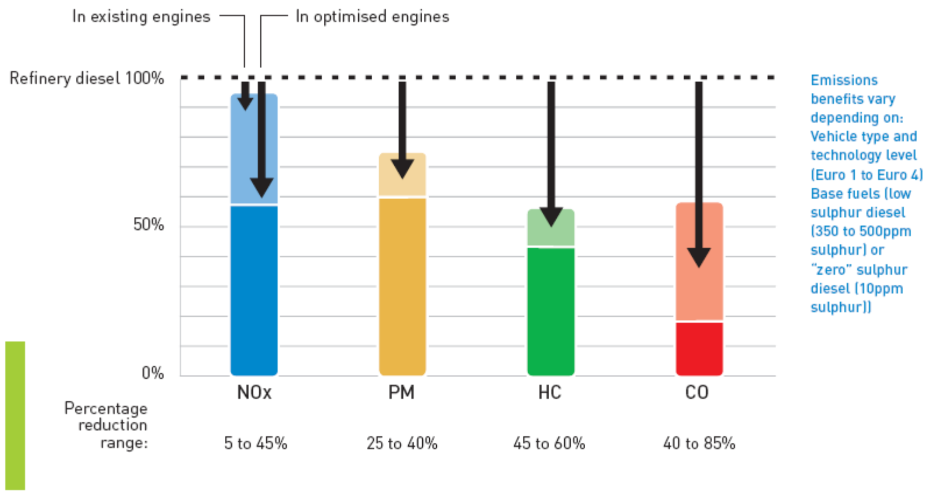
The Alliance for Synthetic Fuels in Europe (ASFE) brings together leading automotive and fuel supply companies: DaimlerChrysler, Renault, Royal Dutch Shell, Sasol Chevron and the Volkswagen Group. They share a commitment to contributing to a reduction in the environmental impact of road transport through improved energy efficiency and cleaner fuels. Their common view is that synthetic fuels have a key role to play in this.

The ASFE objectives are to:

1) Promote synthetic fuels because of their unique and consistent composition and hence their significant contribution to vehicle emission reduction.
2) Support a range of activities in the field of synthetic fuels and sustainable mobility, including research, projects demonstrating the benefits of synthetic fuels including vehicle trials, co-operation with governments and promotion of public awareness.

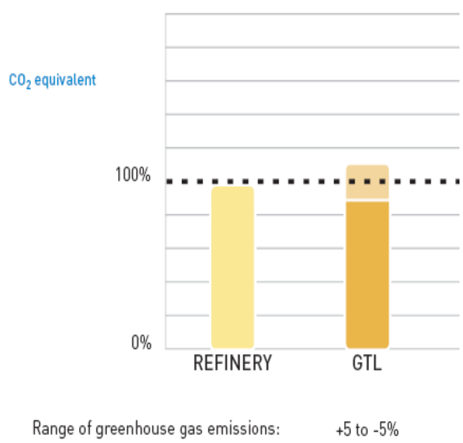
6.5.1 Local emission benefits

ASFE has shown in load trials of synthetic fuels in several European capitals and elsewhere that they provide significant local air quality improvement by reducing tailpipe emissions (particulate matter, nitrogen oxides, carbon monoxide and hydrocarbons). Whereas the application of successive Euro-standards applies to new vehicles only, the introduction of synthetic fuels will have an immediate positive impact on the local emissions from the existing vehicle fleet, particularly in urban areas. When engines are optimized to run on synthetic fuels, further reductions of nitrogen oxides can be obtained as shown below:



Ref: [24]

Regarding CO_2 emissions, the ASFE has, in their reference material, assessed the environmental attributes of the conventional and synthetic fuel technologies by measuring the impact caused through production, transportation and fuel usage on the "Well to Wheel" basis. Their assessments show that CO_2 of the GTL process are comparable to a refinery system (+/- 5%). By linking development of advanced engine and synthetic fuels production technology, it is expected that greater vehicle efficiency gains will lead to further reductions in CO_2 emissions. The ASFE comparison of GTL processes with refinery systems (on a "Well to Wheel" basis) is shown below:



Comparison of GTL processes with refinery systems
("Well to Wheel" basis) [24]

6.5.2 ASFE's Commitment

In view of future EU policy proposals on energy efficiency, security of energy supplies, air quality, and climate change, ASFE members look forward to exploring possible policy options and incentives to boost the availability and encourage wider use of synthetic fuels. Therefore, they are indifferent as to the source of the fuels and accept equally well GTL-, BTL- or CTL-fuels.

6.6 Environmental Permitting

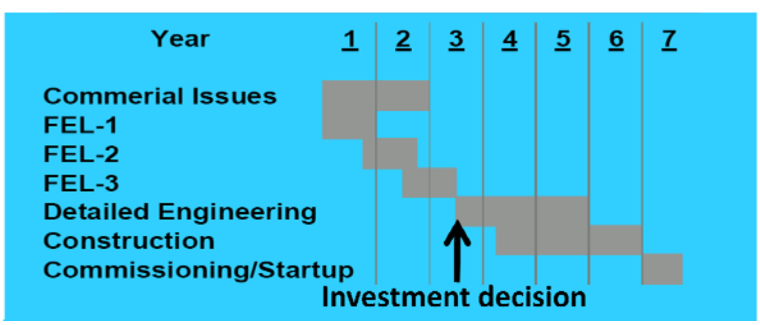
A GTL plant on the North Slope would be required to follow established state and federal permit procedures. It is not within the scope of this report to do a detailed analysis of the permits required. They are expected to be similar to permits for any large industrial facility, including air and water quality permits and most likely including a federal Environmental Impact Statement. Also, since the GTL plant would most likely be located adjacent to existing facilities in the Prudhoe Bay field we do not foresee any unusual permit challenges except for the issue of carbon dioxide emissions capture and sequestration or use in EOR. The permitting plan should ensure, however, that the GTL plant owner has all of the environmental permits in place to begin construction by 2010. The plant is considered to be constructed in a modular way, starting with the first of five 90,000 bbl/d modules. *(The reader is reminded that in general a GTL plant uses, depending on the technology used, between 8 MMBtu to 10 MMBtu of natural gas for each barrel of F-T product produced. Thus a 90,000 bbl/d GTL module will require less than 900 million cubic feet per day of natural gas. A 450,000 bbl/d plant would utilize less than 4,500 mcf/d or 4.5 billion cubic feet per day of natural gas.)* With the permits in hand the GTL plant owner should be able to operate the first module of the plant by 2014, while other modules of the total 450,000 bbl/d complex are under construction.

The chronological sequence of the permitting process is generally characterized by:

1. Developing preliminary project and engineering information for a project description and for the plant a mass balance, leading to the development of a plant emission profile.
2. Initiating pre-application meetings with agencies and information meetings with key stakeholders.
3. Filing permit applications.
4. Negotiating permit terms.
5. Implementing permit conditions.

The following is intended to elucidate somewhat on the these points:

In Section 9 (ECONOMICS) we introduce a timeline for a typical, large size, GTL project. We note that completion of construction and start-up of the larger GTL projects typically takes a 4–5 year period (for a single build), following an investment decision based on Frond End Loading (FEL) studies, sometimes also called Front End Engineering Design (FEED).



(FEL = Front End Loading studies)

In the diagram above three front end studies are included, totaling a combined time requirement of 2 years. The very front-end of every large design project is critical to the long-term success of the plant. While the business plan identifies the economic opportunity, the FEL study or FEED will establish the set of process operating conditions and equipment to achieve the level of reliability, efficiency, and safety required. This design phase sets the direction for the rest of the project. The first front-end study is obviously of a more conceptual kind. The later ones have the intent to narrow down cost estimates as firmly and closely as possible, to define the critical path for the delivery of long lead items, as well as to place of (sometimes non-binding) tenders for the purchase of critical equipment.

It is not unusual for the FEL studies to cost up to 10% of the capital investment. For the case of an Alaska North Slope GTL plant we envision a plant comprising five identical units with a total capacity of 450,000 bbl/d. With the assumption that such plant could cost in the order of U.S. $40 billion, but that the front-end study only needs to be done for one module. Given this, the 10% cost would imply an upfront FEL-study or FEED cost of around $1 billion over 2 years.

Modifications to the existing TAPS pipeline is estimated to cost $1 billion. With the objective to be able to "batch-wise" transport F-T material and conventional North Slope crude oil. (For the layman we can best describe this as transport of material in "sausages", whereby the "sausages" are separated from each other by a rubber ball, also called "pig", so that minimal mixing occurs at the interface of the "sausages"). Such already well-established concepts of transporting different materials in the same pipeline would potentially require few additional pig stations for removal or addition of a pig. We feel that cost and timing requirements of this part falls well within the scope and timing of the plant development studies.

Pre-Application Meetings/Communication with Agencies and Key Stakeholders.

Even before the project description is ready; it is advisable to begin discussions with agencies and key stakeholders. Both agencies and stakeholders should be engaged early in the process to identify issues, permits, and pre-construction studies required to move the process forward. Identifying issues early is particularly important to keeping a project on schedule. At this point in time the stakeholders at the producing side include the Prudhoe Bay producers, ConocoPhillips, BP, Exxon-Mobil, as well as the State of Alaska and the North Slope Borough, along with other private active on the North Slope such as Anadarko Petroleum, BG Energy, Arctic Slope Regional Corp. and Shell.

Hoefler Consulting Group [25], therefore, estimated the timeline for a potential gas spur pipeline from a large gas pipeline in the order of one year. In overview we would expect that it is theoretically possible, if approvals were done immediately, to accomplish the required permitting and begin the first phase of construction by 2010.

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7 The U.S. West Coast Transportation Fuel Market – An Overview

7.1 Summary/Conclusions

The U.S. West Coast transportation fuels market is arguably the best market for F-T fuels in the world consuming over 3 million barrels per day of some of the cleanest transport fuels that are used. California, the 10th largest economy in the world, accounts for more than 63% of this volume and has the highest wholesale fuel costs. Since the California wholesale price is driven by the highest possible fuel quality, F-T fuels fit right into the market.

Should a U.S West Coast/Alaska GTL market development require any political clout, it is comfortable to know that from a political influence level one out of five representatives in Congress represent Washington, Oregon, Idaho, Nevada, Arizona and California.

Six factors are important to the success of an Alaska GTL or Coal-to-Liquids program.

- A market that represents one out of five members in Congress,
- A market that is growing at a rate that will exceed refining capacity additions,
- A market place that values ultra-clean fuels, especially low aromatic diesels,
- An environmentally active population that is willing to not only support clean fuels but to pay for them,
- Refining centers that are on the water so that F-T fuels can be delivered to the beginning of the value chain and,
- A place to sequester CO_2 derived from the manufacture of F-T fuels.

Considering a recent, March 2008 (the CARB price was over $3.50/gallon the end of April 2008) California CARB diesel refinery-gate price of $ 3.20/gallon it is calculated that a $40 billion 450,000 bbl/d North Slope GTL facility would be able to pay a netback price over $9.00/mcf for natural gas delivered to the plant inlet. If the North Slope GTL plant was built in phases, the netback number would be higher. Still we have assumed no increase in net-back value from the NGL's sold at Valdez over a central Alberta under the gas pipeline option.

7.2 Introduction

The single largest market in the U.S. for transportation fuels is California. It is the between the 7th and 10th largest economy in the world depending on how the measurement is done, and represents the largest regional economy in the U.S. California ranks third in the nation in petroleum refining capacity and accounts for more than one-tenth of total U.S. capacity. The three major refining centers on the West Coast; Los Angeles, San Francisco and Tacoma/Anacortes serve almost 60 million people in Washington, Oregon, Idaho, Nevada, Arizona and California. The people in these six states account for one out of five representatives in Congress, which is important as F-T will need congressional support to build new refineries in the U.S. The people living in these states are environmentally active and accept that clean fuels cost more money. With the ability of the Alaska North Slope GTL plant to make use of the CO_2 produced these states are willing to support F-T in Alaska.

By delivering F-T transportation fuels via products tankers from Valdez to the West Coast refining centers Alaska can provide the transportation fuels market with the capability to make any blend of F-T from 1% to 100%. This provides the greatest flexibility to the refiner to optimize the benefits of F-T to the consumer and the netback to Alaska. In addition, the entire Pacific Rim is available as a market, insuring the highest market price for Alaskan F-T.

Due to the relative isolation and specific requirements of the California fuels market, California motorists are particularly vulnerable to short-term spikes in the price of motor gasoline and diesel. No pipelines connect West Coast refining centers to other major U.S. refining centers, and California refineries often operate at near maximum capacity due to high demand for petroleum products. When an unplanned refinery outage occurs, replacement supplies must be brought in via tanker. There are only one or two refineries in the world that can produce diesel fuels capable of meeting the low aromatic requirements, (10% aromatics with the U.S. standard 30%) California demands. F-T diesel from the GTL/CTL process is essentially aromatic and sulfur free. For some time California refiners have purchased, and paid a premium for, GTL products from Shell's GTL plant in Malaysia to use as blending stock.

The U.S. Air Force has also determined that F-T jet fuel / diesel is the fuel of the future and plans to have converted its fleet of aircraft to burn a blend of 50% F-T and 50% conventional petroleum based jet fuel by 2016. A delivery point in Valdez that can service Air Force needs throughout the West Coast / Pacific Rim is particularly attractive. The Department of Defense has also determined that F-T middle distillate (kerosene/diesel) is the ideal fuel for the "one fuel" military of the future. An Alaskan North Slope GTL program, along with a Cook Inlet Coal-to-Liquids program, will put Alaska in the forefront of F-T manufacture and supply.

The National Defense Council Foundation (NDCF) prepared a report in 2003[1], showing that hidden costs of the U.S. refining capacity shortfall and imports of crude oil cost the American consumer an additional $2.00 to $2.50 per gallon at the pump. These hidden costs will only drop when the U.S. adds both refining capacity and a domestic crude oil replacement. U.S. based GTL, and CTL and projects are one of the few programs that can fill this need.

[1] *National Defense Council Foundation "America's Achilles Heel: The Hidden Costs Of Imported Oil – A Strategy for Energy Independence* ■ (703) 836-5402 ■ Email Address: **ndcf@erols.com** ■

Without question there will need to be Congressional support to add refining capacity in the U.S. Existing refiners are not going to supporting this effort in Congress without some benefits. The Alaska congressional delegation has led the way to get GTL's classified as an "alternative fuel" and Senator Stevens was responsible for Congress passing energy credits for F-T fuels. These two efforts made GTL and CTL economic in the U.S. Some would say at $100/bbl crude these projects don't need economic support. If the capital cost to build new energy projects had stayed at 2005 levels that would be a true statement. Unfortunately the cost of all of these energy projects, whether a gas pipeline or GTL plant, has doubled or tripled in the last few years. Banks will not lend money based on $100/bbl crude oil and investors put money into 20 year payout projects hoping that crude oil will stay at $100/bbl. The single largest expense in an FT plant is debt recovery. Once debt is paid out these plants can compete with crude oil based products well below $50/bbl. An additional benefit is that as we add refining capacity to the U.S., the very high refining margins now enjoyed by refiners will come down – saving Americans money at the pump.

Therefore F-T still needs Congressional support to keep the lower excise tax rates on these alternative fuels in place. Currently Congress renews these programs every five years. Ethanol has enjoyed its economic support for over 30 years, and CNG, LNG (what support does LNG get?), propane nearly as long. Biodiesel and F-T fuels were added in 2006. The more people who are recipients of these clean fuel benefits, the more support there will be in Congress to support an F-T long program.

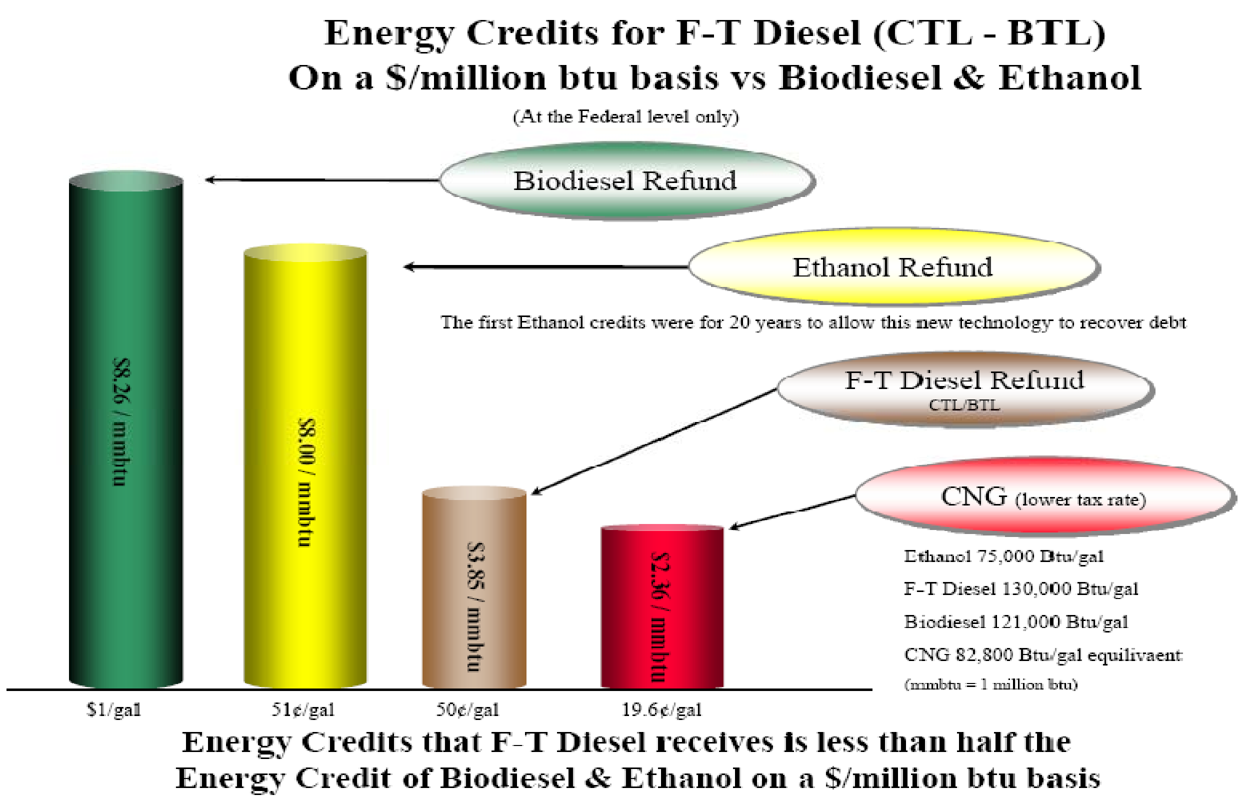
7.3 Lower Excise Taxes – Road Taxes

In 1996, when Alaska Natural Gas To Liquids (ANGTL) first approached the State of Alaska, ARCO, BP and Exxon with the idea of a GTL plant prices for crude oil were low and we believed that some sort of price support for a GTL plant was needed if its products were only going to receive the same price as petroleum-based transport fuels at the pump. The main reason for this was the need to recover the capital cost of the GTL plant in the fuel price at the pump, while petroleum-based transport fuels from refineries in general had no capital cost component to recover.

ANGTL approached the IRS and asked the following question: "Given the fact that natural gas (compressed natural gas or CNG) consumed in a motor vehicle, is taxed at a much lower rate than petroleum based diesel, would a transport fuel derived from natural gas via the Fischer-Tropsch (F-T) process also qualify for the same lower tax rate?" In 1998, the IRS indicated that they saw no reason why GTL transport fuels should not also enjoy the same lower federal excise tax rate as CNG. The State of California said they concurred with the IRS on this point. Thus F-T diesel when sold at the pump at the same price as petroleum based diesel should receive a 31¢/gallon "premium" or $13.02/bbl.

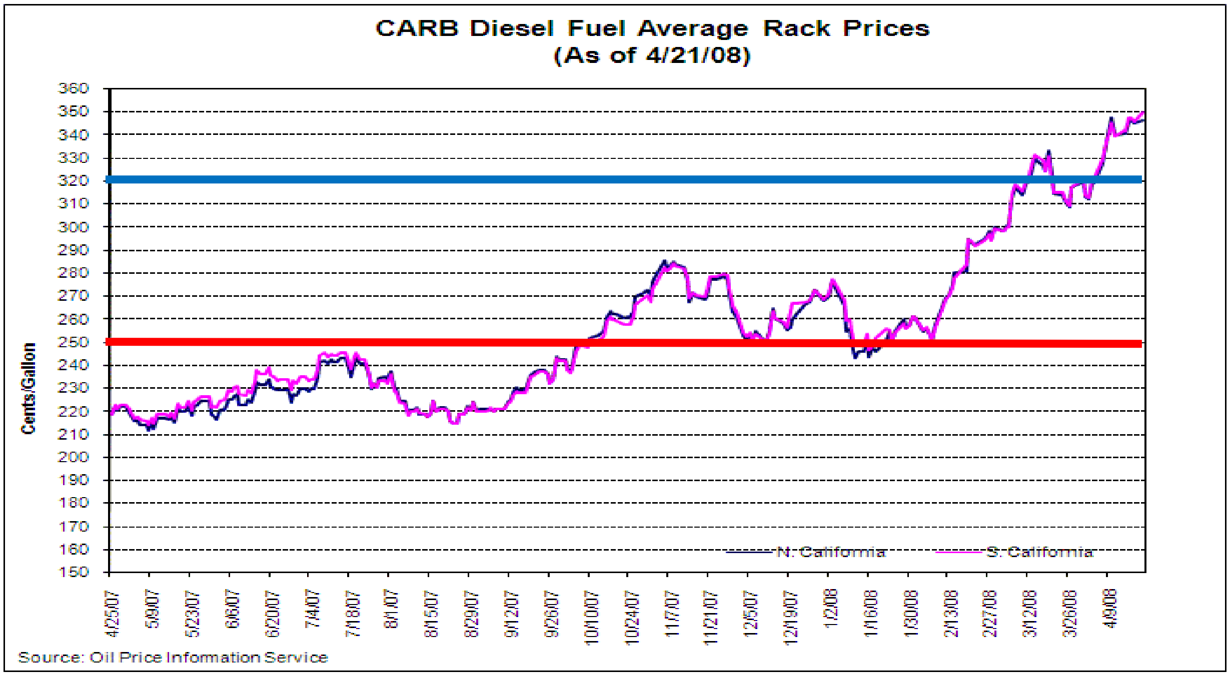
It is worth noting here that this lower excise tax rate for F-T diesel made from natural gas, did not apply to F-T fuels made from coal or biomass. ANGTL then went to Congress to seek support for F-T fuels regardless whether they were made from natural gas, coal or biomass. Through the support of the Alaska delegation, and in particular Senator Ted Stevens, language was placed in the 2005, Transportation Bill, approved by Congress in August of 2005 and signed into law by President Bush in September 2005, granting Energy Credits similar to those approved for ethanol and biodiesel. The credits for F-T transportation fuels equaled 50¢/gallon or $21/bbl for F-T fuels made from coal and biomass. ANGTL did not ask that these credits also apply to F-T transport products made from natural gas but it would be a simple modification of the existing language to include F-T fuels made from natural gas. Thus, when one looks at the netback for F-T fuels sold in the U.S. a minimum of 31¢/gallon to the wholesale price to potentially as much as 50¢/gallon can be added. It should be kept in mind the 50¢/gallon Energy Credit is only on the Federal level. California has indicated that they will also provide a lower excise tax rate on F-T diesel sold in California, but for this analysis we have assumed this to be at zero value.

The chart below shows the relative cost on a Btu basis for the energy credits (lower tax rate) provided to CNG, biodiesel and ethanol. Note that the chart is only showing the excise tax rebate on the federal level. The price at the gas pump has the refinery wholesale rack price, transportation costs from the refinery to the gas station, a profit for the gas station along with federal, state and local taxes included in the pump price. Typically both the state and federal government provide a lower tax rate for these clean burning alternative transportation fuels and in some cases the local taxing authority also provides for a lower tax rate. In our example we use both the federal and state (California) lower tax rate applied to CNG (the 31¢/gallon tax savings) but for the 50¢/gallon Energy Credit we are only using the federal tax savings.



7.4 NET BACK TO PRUDHOE BAY

The price of transportation fuel is continuously in motion reflecting, among other influences, crude oil pricing and seasonal supply and demand. The wholesale rack (tailgate of a refinery)



price for diesel in CA is at $3.50/gallon (third week of April 2008). For this analysis we will use a wholesale rack price of $3.20/gallon. With the potential of adding between 31¢ to 50¢ per gallon for lower excise taxes on F-T diesel we will use an assumed 31¢/gallon price support.

Assuming the Alaska F-T diesel to have approximately 130,000 Btu/gal, one winds up with an energy equivalent price for natural gas, having itself 1000 Btu/scf, of $27/mcf. This price represents a "City Gate" price for natural gas. It has to be delivered to the customer (similar to delivering diesel from the refinery to the local gasoline stations) and taxes need to be applied to determine the end user price (pump price).

Going the other direction from the refinery tailgate price back to the inlet of a North Slope GTL plant, we would expect the following deductions (see Section 9 for the details): $2/bbl shipping costs from Valdez to either San Francisco or Los Angeles refining/distribution centers; $5/bbl for shipping via TAPS; $31.75/bbl for a 20 year debt recovery (7.5% commercial debt and 20% IRR for the equity owner) for a 450,000 bbl/d GTL plant costing $40.5 billion; $18/bbl for operating costs. Thus the $3.20 (blue line in the above graph) plus 31¢, which is equivalent to $147/bbl, minus $56.75/bbl for expenses, results in a gross number at Prudhoe Bay of $90.67/bbl.

To express this in gas terms, let's assume that a middle-of-the-road GTL technology requires 8.5 million Btu of natural gas to make one barrel of F-T (see Section 3). *(Some people prefer to say that it takes between 8 to 10 mcf of natural gas to make 1 barrel of F-T products).* **Thus the GTL plant would net back $9.09/mcf* for the gas delivered to the plant inlet.** A 450,000 bbl/d GTL plant will require about 4.1 billion cubic feet/d of natural gas. *Note, if we use the Shell Bintulu conversion rate of 8.3 million Btu/bbl, the netback is $9.30/mcf.*

**We have assumed that only 80% of the GTL plant output will be F-T diesel, 5% would be LPG's and 15% would be F-T naphtha. Further we assumed that only the F-T diesel and LPG's (road transportation fuels) would receive the benefit of lower excise taxes, thus there is no additional economic incentive added to the value of F-T naphtha. Lastly, we have assumed that value of F-T naphtha would be 85% of that of F-T diesel.*

As sensitivities we would like to point out that, if the market price dropped to $2.50/gallon (red line in the above graph – which is $42/bbl below early May 2008 prices), the netback would reduce to $6.32/mcf *($6.50/mcf if we use the Shell Bintulu conversion rate).* If the Alaska GTL plant qualified for the current 50¢/gallon energy credit like F-T made from coal and bio-mass, which we believe Congress would approve, these numbers would increase by 81¢/mcf.

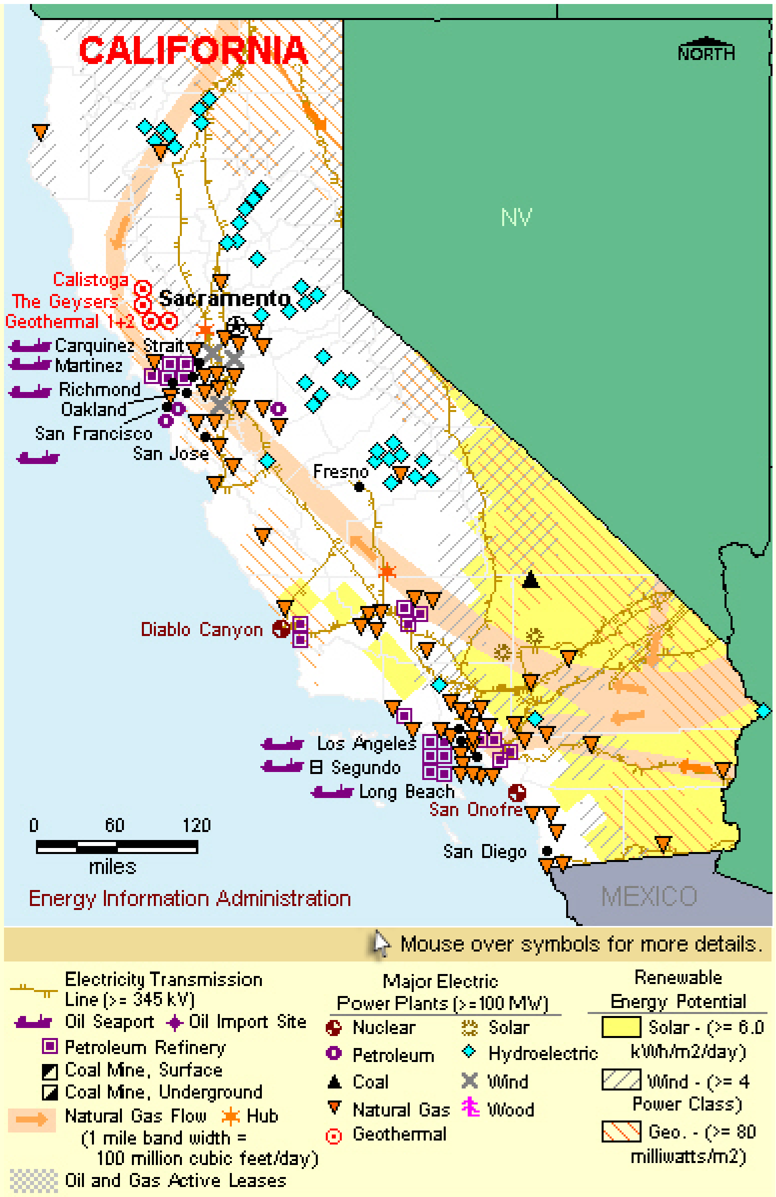
7.5 California is the largest transportation fuels market in the six-state area and is the highest priced market in terms of wholesale value in the U.S.

The six state area of Washington, Oregon, California, Arizona, Nevada, Idaho (Alaska's GTL/CTL West Coast market area) has a population base close to 60 million, represents 15.3% of U.S. refining capacity with over 11% of that in California. California is the third largest refining center in the U.S. The region consumes almost a million barrels per day of middle distillate fuels and the market is growing at about 2% to 3% per year. This trend is expected to increase as more fuel efficient cars/light trucks come on the road fueled primarily with ultra clean diesel.

California tends to lead the U.S. in adopting cleaner emission standards and better fuels. The California Energy Commission (CEC) has been a strong advocate for F-T and believes California's future lies with F-T technology coupled with CO_2 sequestering. The CEC has worked with ANRTL and others to educate Congress on the benefits of F-T fuels. The CEC supports an Alaska F-T program and will work with Alaska to promote long term support for GTL/CTL in Congress.

The following summaries are taken from the EIA summary of States Energy Profiles. These six States make of the bulk of PADD 5 and are for the most part isolated from the remainder of the U.S. transportation fuels products distribution system.

7.6 California:



California Quick Facts

- California ranks third in the nation in refining capacity and its refineries are among the most sophisticated in the world.
- California's per capita energy consumption is low, in part due to mild weather that reduces energy demand for heating and cooling.
- California leads the nation in electricity generation from non-hydroelectric renewable energy sources, including geothermal power, wind power, fuel wood, landfill gas, and solar power. California is also a leading generator of hydroelectric power.
- California imports more electricity from other states than any other state.
- In 2000 and 2001, California suffered an energy crisis characterized by electricity price instability and four major blackouts affecting millions of customers.

Overview

Resources and Consumption

California is rich in conventional and renewable energy resources. It has large crude oil and substantial natural gas deposits in six geological basins, located in the Central Valley and along the Pacific coast. Most of those reserves are concentrated in the southern San Joaquin Basin. More than a dozen of the nation's 100 largest oil and gas fields are located in California, including the Belridge South field, the second largest in the contiguous United States. In addition, federal assessments indicate that large undiscovered deposits of recoverable oil and gas are likely to be found in the federally administered Outer Continental

Shelf (OCS), although federal law currently prohibits oil and gas leasing in that area. California's renewable energy potential is extensive. The State's hydroelectric power potential ranks second in the nation (behind Washington state), and substantial geothermal and wind power resources are found along the coastal mountain ranges and the eastern border with Nevada. High solar energy potential is found in southeastern California's deserts.

California is the most populous State in the nation and its total energy demand is second only to Texas. Although California is a leader in the energy-intensive chemical, forest products, glass, and petroleum industries, the state has one of the lowest per capita energy consumption rates in the country. The California government's energy-efficiency programs have contributed to lower per capita energy consumption. Driven by high demand from California's motorists, major airports, and military bases, the transportation sector is the state's largest energy-consumer. More motor vehicles are registered in California than any other state, and worker commute times are among the longest in the country.

Petroleum

California is one of the top producers of crude oil in the nation, with output accounting for more than one-tenth of total U.S. production. Drilling operations are concentrated primarily in Kern County and the Los Angeles basin, although substantial production also takes place offshore in both state and federal waters. Concerns regarding the cumulative impacts of offshore oil and gas development, combined with a number of major marine oil spills throughout the world in recent years, have led to a permanent moratorium on offshore oil and gas leasing in California waters and a deferral of leasing in federal waters. However, development on existing state and federal leases is not affected and may still occur within offshore areas leased prior to the effective date of the moratorium.

A network of crude oil pipelines connects production areas to refining centers in the Los Angeles area, the San Francisco Bay area, and the Central Valley. California refiners also process large volumes of Alaskan and foreign crude oil received at ports in Los Angeles, Long Beach, and the San Francisco Bay Area. Crude oil production in California and Alaska is in decline and California refineries have become increasingly dependent on foreign imports. Led by Saudi Arabia and Ecuador, foreign suppliers now provide more than two-fifths of the crude oil refined in California; however, California's dependence on foreign oil remains less than the national average.

California ranks third in the United States in petroleum refining capacity and accounts for more than one-tenth of total U.S. capacity. California's largest refineries are highly sophisticated; they are capable of processing a wide variety of crude oil types and are designed to yield a high percentage of light products like motor gasoline. To meet strict Federal and State environmental regulations, California refineries are configured to produce cleaner fuels, including reformulated motor gasoline and low-sulfur diesel.

Most California motorists are required to use a special motor gasoline blend called California Clean Burning Gasoline (CA CBG). In the ozone non-attainment areas of Imperial County and the Los Angeles metropolitan area, motorists are required to use California Oxygenated Clean Burning Gasoline, and the Los Angeles area is also required to use oxygenated motor gasoline during the winter months. By 2004, California completed a transition from methyl tertiary butyl-ether (MTBE) to ethanol as a gasoline oxygenate additive, making California the largest ethanol fuel market in the United States. There are four ethanol production plants in central and southern California, but most of California's ethanol supply is transported by rail from corn-based producers in the Midwest. Some supply is also imported from abroad.

Due to the relative isolation and specific requirements of the California fuel market, California motorists are particularly vulnerable to short-term spikes in the price of motor gasoline. No pipelines connect California to other major U.S. refining centers, and California refineries often operate at near-maximum capacity due to high demand for petroleum products. When an unplanned refinery outage occurs, replacement supplies must be brought in via marine tanker. Locating and transporting this replacement gasoline (which must conform to the State's strict fuel requirements) can take from two to six weeks.

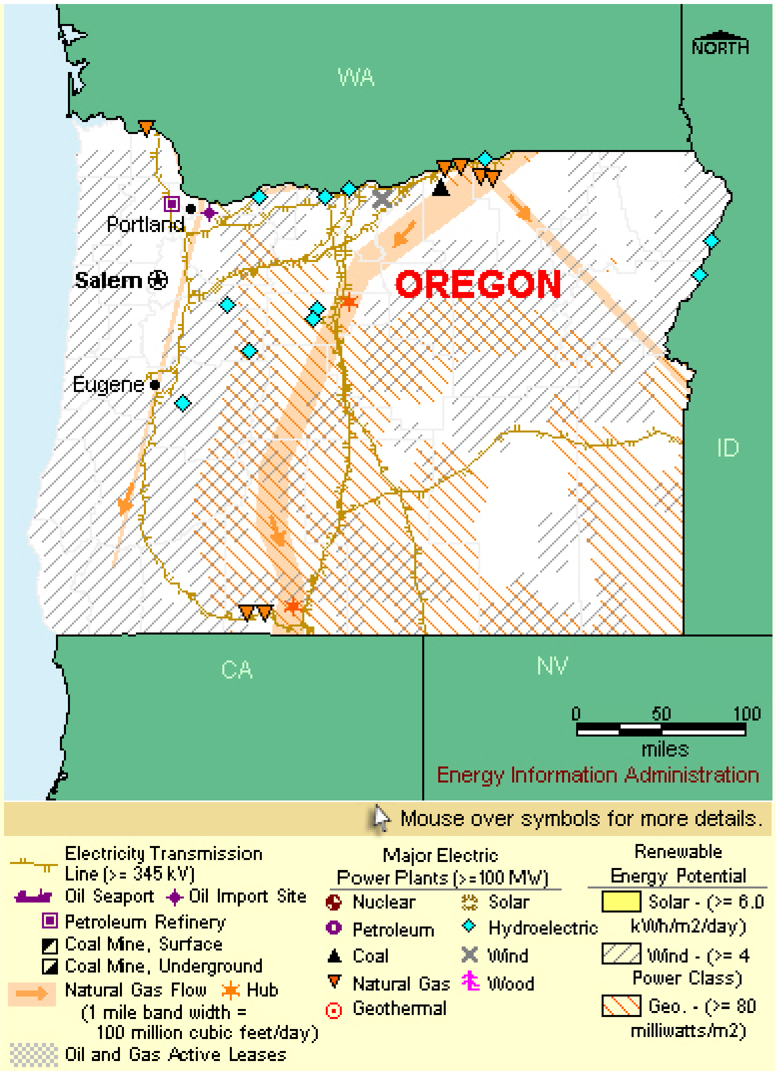
Consumption

per Capita	California	U.S. Rank	Period
Total Energy	232 million Btu	48	2005
by Source	**California**	**Share of U.S.**	**Period**
Total Energy	8,359,767 billion Btu	8.3%	2005
Total Petroleum	705,973 thousand barrels	9.3%	2005
Motor Gasoline	381,301 thousand barrels	11.4%	2005
Distillate Fuel	96,902 thousand barrels	6.4%	2005
Liquefied Petroleum Gases	12,375 thousand barrels	1.7%	2005
Jet Fuel	104,612 thousand barrels	17.1%	2005

Economy

Population and Employment	California	U.S. Rank	Period
Population	36.6 million	1	2007
Civilian Labor Force	18.3 million	1	2007
Per Capita Personal Income	$41,571	21	2007

7.7 Oregon:



Oregon Quick Facts

- Oregon is one of the nation's leading generators of hydroelectric power, which accounts for more than one-half of State electricity generation.
- Major transmission lines connect Oregon's electricity grid to California and Washington state, allowing for large interstate energy transfers.
- Liquefied natural gas (LNG) import facilities have been proposed in Oregon to help meet demand for the fuel.
- The geologically active basin and range country in southeastern Oregon, as well as the Cascade Mountains in western Oregon, are promising sites for geothermal energy development.

Overview

Resources and Consumption

Oregon has few conventional energy resources but is rich in renewable energy potential. The Columbia River in the north and several smaller waterways flowing from the Cascade Mountains give Oregon some of the highest hydroelectric power potential in the United States. Much of the state has considerable wind power potential. The geologically active basin and range country in southeastern Oregon, as well as the Cascades in western Oregon, are promising sites for geothermal energy development. Oregon's total energy consumption is low, although the state is a leader in the energy-intensive forest products industry. The transportation sector is the leading energy-consuming sector in Oregon, followed closely by the industrial and residential sectors.

Petroleum

Oregon's only refinery, located in the Portland area, primarily produces asphalt and vacuum gas oil. The state receives petroleum-based transportation and heating fuels from Washington and northern California. Tanker trucks from California supply southern Oregon, while ships and barges deliver additional product from San Francisco to the Portland area. The use of oxygenated motor gasoline is required in the Klamath County and Medford areas during the winter months.

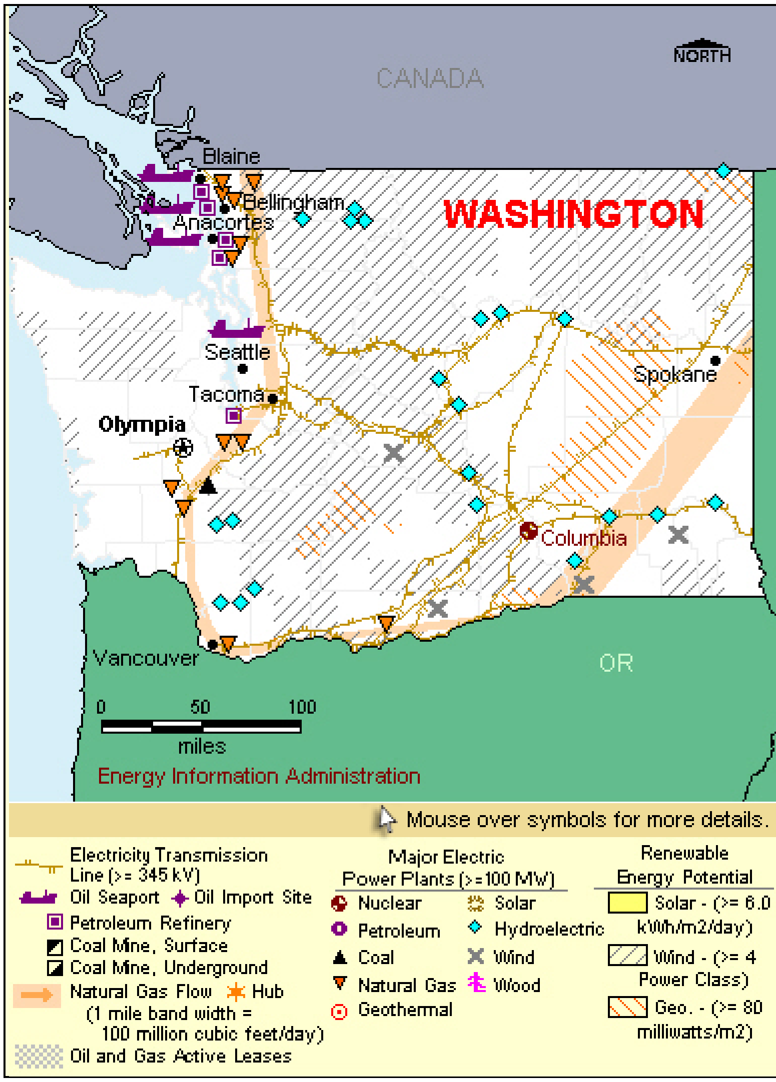
Consumption

per Capita	Oregon	U.S. Rank	Period
Total Energy	302 million Btu	39	2005
by Source	**Oregon**	**Share of U.S.**	**Period**
Total Energy	1,095,661 billion Btu	1.1%	2005
Total Petroleum	71,306 thousand barrels	0.9%	2005
Motor Gasoline	37,488 thousand barrels	1.1%	2005
Distillate Fuel	17,853 thousand barrels	1.2%	2005
Liquefied Petroleum Gases	1,278 thousand barrels	0.2%	2005
Jet Fuel	5,402 thousand barrels	0.9%	2005

Economy

Population and Employment	Oregon	U.S. Rank	Period
Population	3.7 million	27	2007
Civilian Labor Force	1.9 million	26	2007
Per Capita Personal Income	$34,784	42	2007

7.8 Washington:



Washington Quick Facts

- Washington is the leading hydroelectric power producer in the nation. Hydroelectric power accounts for nearly three-fourths of state electricity generation.
- The Grand Coulee hydroelectric power plant on the Columbia River is the highest capacity electric plant in the United States.
- With five refineries, Washington is a principal refining center for the Pacific Northwest.
- State jet fuel consumption is among the highest in the nation, due in part to several large Air Force and Navy installations.

Resources and Consumption

Washington has few fossil fuel resources but has tremendous renewable power potential. The Columbia and Snake Rivers are immense hydroelectric power resources. The state's western forests offer fuel wood resources, and large areas of the state are conducive to wind and geothermal power development. Washington's population and total energy consumption are relatively high. Transportation is the leading energy-consuming sector in the state, followed by the industrial and residential sectors. Washington is a leader in the energy-intensive forest products industry and is the site of several large U.S. military bases.

Petroleum

Although Washington has no indigenous crude oil production, it is a principal refining center serving Pacific Northwest markets. Five refineries receive crude oil supply primarily by tanker from Alaska. However, because Alaskan production is in decline, Washington's refineries are becoming increasingly dependent on crude oil imports from Canada and other countries. The Trans Mountain Pipeline from Alberta supplies more than one-tenth of Washington's crude oil supply. Washington's total petroleum demand is high. Jet fuel consumption is among the highest in the nation, due in part to several large Air Force and Navy installations. The use of oxygenated motor gasoline is required in the Spokane area during the winter months.

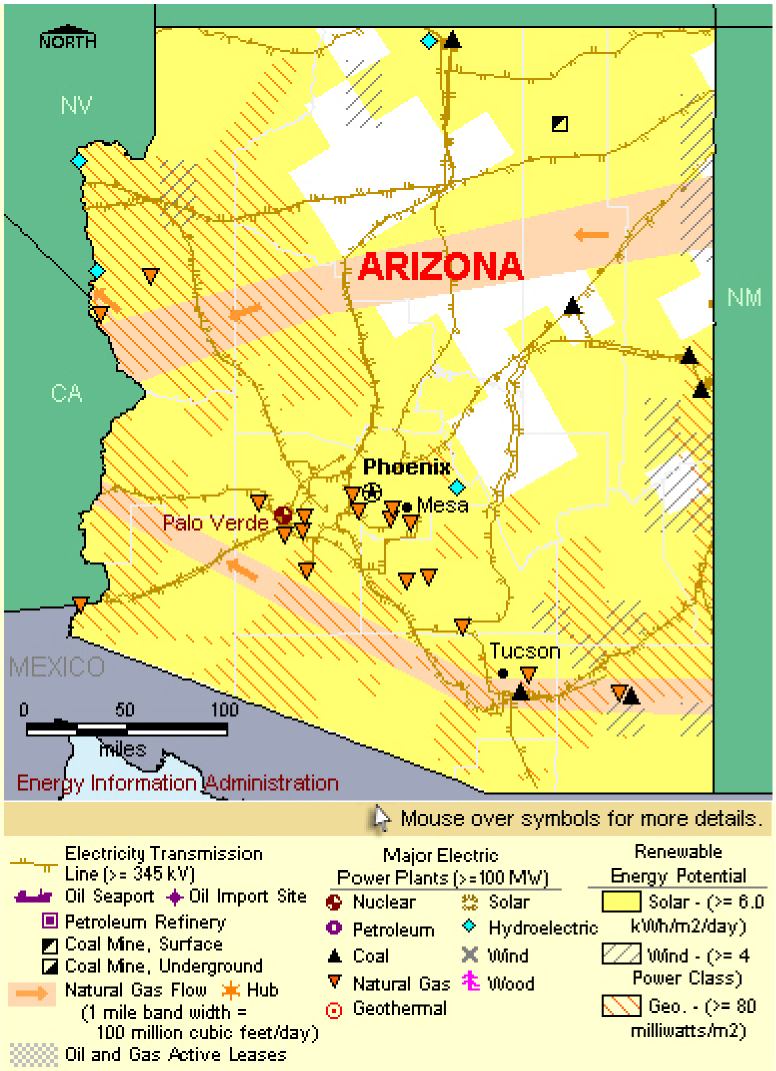
Consumption

per Capita	Washington	U.S. Rank	Period
Total Energy	328 million Btu	30	2005
by Source	**Washington**	**Share of U.S.**	**Period**
Total Energy	2,058,808 billion Btu	2.1%	2005
Total Petroleum	153,213 thousand barrels	2.0%	2005
Motor Gasoline	65,216 thousand barrels	2.0%	2005
Distillate Fuel	24,753 thousand barrels	1.6%	2005
Liquefied Petroleum Gases	2,779 thousand barrels	0.4%	2005
Jet Fuel	18,480 thousand barrels	3.0%	2005

Economy

Population and Employment	Washington	U.S. Rank	Period
Population	6.5 million	14	2007
Civilian Labor Force	3.4 million	14	2007
Per Capita Personal Income	$40,414	25	2007

7.9 Arizona:



Arizona Quick Facts

- Arizona's Palo Verde nuclear power plant is the highest capacity nuclear plant in the United States.
- Arizona power plants export large amounts of electricity to neighboring states, particularly to markets in Southern California.
- Arizona's large desert areas offer the highest solar power potential in the country.
- Substantial coal production takes place in the Black Mesa Basin in northeast Arizona.

Overview

Resources and Consumption

Arizona has substantial coal deposits but few other fossil fuel resources. The coal deposits are concentrated in the Black Mesa Basin in the northeast part of the State. Arizona has one nuclear power plant and extensive solar energy potential. Its large desert areas offer the highest solar power potential in the country, and the Colorado River is a tremendous source of hydropower. While Arizona ranks near the middle of the states in total energy consumption, per capita energy consumption is low, and the state economy is not energy intensive. The transportation sector is the leading energy-consuming sector in the state.

Petroleum

Arizona's annual crude oil production is minimal. Arizona has no refineries and receives its petroleum product supply via two pipelines, one from southern California and the other from El Paso, Texas. In summer 2003, a rupture on the line from El Paso caused an oil spill and shut down the section between Tucson and Phoenix. The accident caused shortages at Phoenix area motor gasoline fueling stations. A new refinery in Yuma County, Arizona, about 100 miles southwest of Phoenix, has been proposed and is expected to be operational by 2010. The refinery would receive crude oil supplies via a pipeline from Mexico and would ease motor gasoline supply constraints throughout the state. An oxygenated motor gasoline blend is used in the Tucson area during the winter and in Maricopa County (Phoenix) year-round.

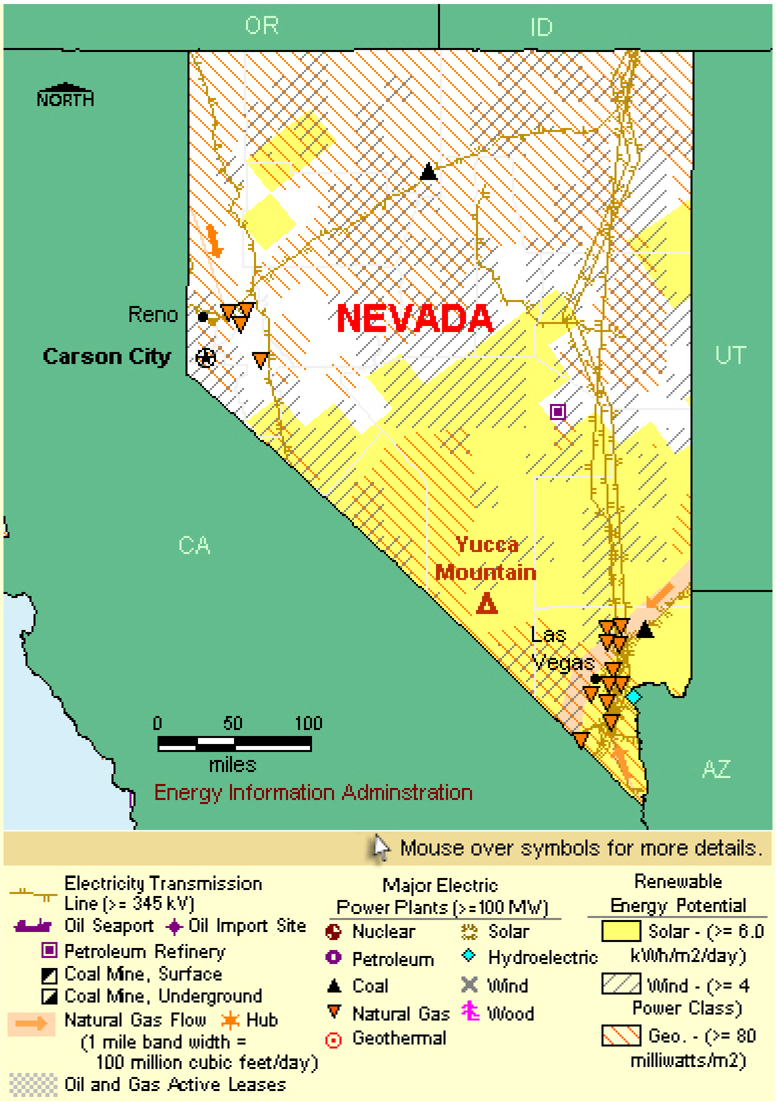
Consumption

per Capita	Arizona	U.S. Rank	Period
Total Energy	249 million Btu	46	2005
by Source	**Arizona**	**Share of U.S.**	**Period**
Total Energy	1,479,658 billion Btu	1.5%	2005
Total Petroleum	108,602 thousand barrels	1.4%	2005
Motor Gasoline	67,483 thousand barrels	2.0%	2005
Distillate Fuel	25,930 thousand barrels	1.7%	2005
Liquefied Petroleum Gases	1,395 thousand barrels	0.2%	2005
Jet Fuel	8,018 thousand barrels	1.3%	2005

Economy

Population and Employment	Arizona	U.S. Rank	Period
Population	6.3 million	17	2007
Civilian Labor Force	3.1 million	21	2007
Per Capita Personal Income	$33,029	47	2007

7.10 Nevada:



Nevada Quick Facts

- Nevada has large geothermal resources and is second only to California in the generation of electricity from geothermal energy.
- Though total petroleum consumption is low, Nevada's jet fuel consumption is disproportionately high due in large part to demand from airports in Las Vegas and Reno and from two air bases.
- The state's largest power generating plant, the Mohave Generating Station, which was fueled primarily with coal, was shut down at the end of 2005 for failing to install agreed-upon pollution-control equipment.
- The U.S. Department of Energy plans to build the Nation's first long-term geologic repository for spent nuclear fuel and high-level radioactive waste at Yucca Mountain, which is located on federally protected land about 100 miles northwest of Las Vegas.

Overview

Resources and Consumption

Nevada is rich in renewable energy potential but has few fossil energy resources. Nevada leads the nation in geothermal power potential and much of the state is suitable for wind power development. The Colorado River, which forms Nevada's southern border, is a powerful hydroelectric power resource. Nevada's population and total energy consumption are low and the State's economy is not energy intensive. Due in part to the Las Vegas tourism industry, the transportation sector is the leading energy-consuming sector in the State.

Petroleum

Nevada has one small crude oil refinery that produces primarily asphalt and diesel fuel and relies on California refineries for nearly all of its transportation fuels. Three petroleum product pipelines transport supply from California refining centers to the Las Vegas and Reno fuel markets. Although total petroleum consumption is low, Nevada's jet fuel consumption is disproportionately high due to demand from airports in Las Vegas and Reno and from two military air installations. The Las Vegas metropolitan area requires the year-round use of a cleaner burning gasoline (CBG) blend, which has low volatility and contains oxygenates. Also the Reno metropolitan area requires the use of oxygenated motor gasoline during the winter months.

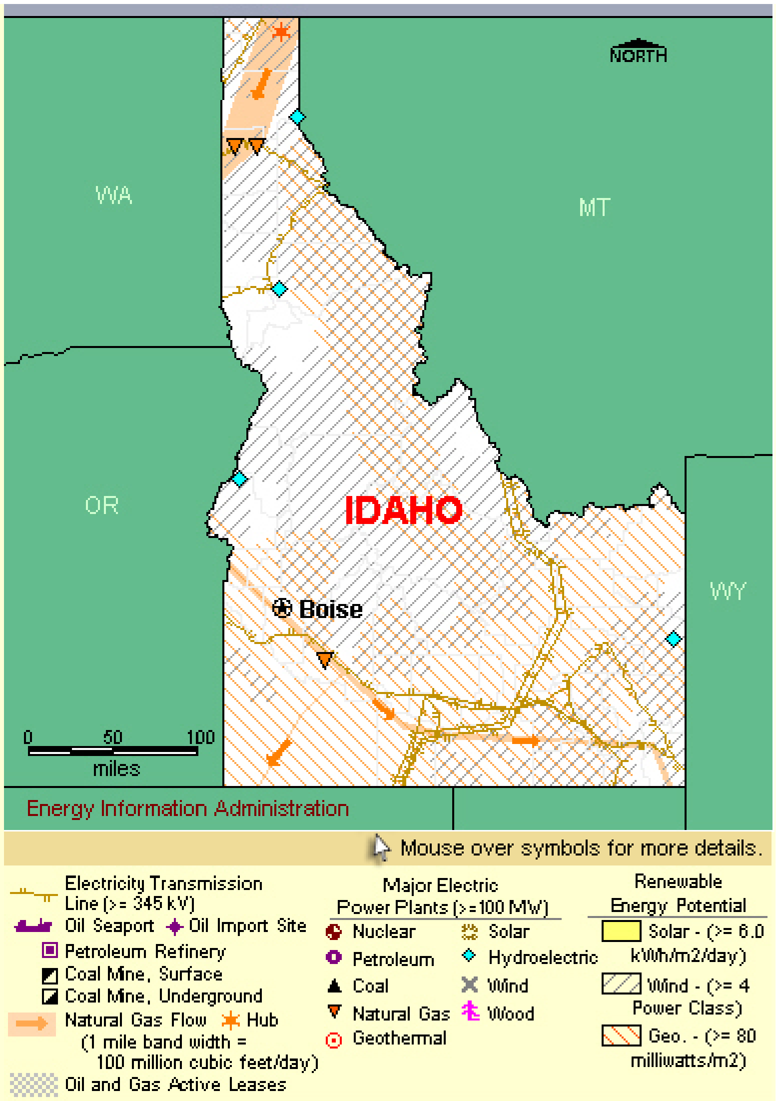
Consumption

per Capita	Nevada	U.S. Rank	Period
Total Energy	302 million Btu	37	2005
by Source	**Nevada**	**Share of U.S.**	**Period**
Total Energy	727,843 billion Btu	0.7%	2005
Total Petroleum	51,115 thousand barrels	0.7%	2005
Motor Gasoline	27,137 thousand barrels	0.8%	2005
Distillate Fuel	12,452 thousand barrels	0.8%	2005
Liquefied Petroleum Gases	931 thousand barrels	0.1%	2005
Jet Fuel	8,157 thousand barrels	1.3%	2005

Economy

Population and Employment	Nevada	U.S. Rank	Period
Population	2.6 million	35	2007
Civilian Labor Force	1.4 million	35	2007
Per Capita Personal Income	$40,480	25	2007

7.11 Idaho:



Idaho Quick Facts

- Hydroelectric power plants supply nearly four-fifths of Idaho's electricity generation.
- The Hells Canyon Complex on the Snake River is the largest privately owned hydroelectric power complex in the Nation.
- In March 2006, Idaho established a 2-year moratorium on licensing or processing proposals for new coal-fired power plants.
- Idaho is one of the few states that uses conventional motor gasoline statewide.

Overview

Resources and Consumption

Idaho is rich in renewable energy resources but has few fossil fuel reserves. The Snake River and several smaller river basins offer Idaho some of the greatest hydroelectric power resources in the Nation. Idaho's geologically active mountain areas have substantial geothermal and wind power potential. The state economy is energy intensive, and energy-consuming industries include mining, forest products, and transportation equipment. Although Idaho's total energy consumption is low when compared with other states, the total population is also low, and, as a result, per capita energy consumption is close to the national average.

Petroleum

Idaho markets receive the majority of their petroleum product supply from refineries in Montana and Utah via two petroleum product pipelines; however, western markets also receive petroleum products from Washington area refining centers. Total petroleum consumption is low. Idaho is one of the few States that uses conventional motor gasoline statewide. (Most states require the use of specific gasoline blends in non-attainment areas due to air-quality considerations.)

Consumption

per Capita	Idaho	U.S. Rank	Period
Total Energy	353 million Btu	23	2005
by Source	**Idaho**	**Share of U.S.**	**Period**
Total Energy	503,160 billion Btu	0.5%	2005
Total Petroleum	29,502 thousand barrels	0.4%	2005
Motor Gasoline	14,806 thousand barrels	0.4%	2005
Distillate Fuel	10,198 thousand barrels	0.7%	2005
Liquefied Petroleum Gases	1,512 thousand barrels	0.2%	2005
Jet Fuel	819 thousand barrels	0.1%	2005

Economy

Population and Employment	Idaho	U.S. Rank	Period
Population	1.5 million	39	2007
Civilian Labor Force	0.8 million	40	2007
Per Capita Personal Income	$31,197	50	2007

8 Federal Support for GTL

8.1 Summary/Conclusions

There are many different forms of federal support for alternative or new fuel programs developed in the U.S. Congress has historically provided support in the form of loan guarantees, co-funding, accelerated depreciation, mandatory requirements to use a specific fuel, emission requirements that can only be met through the use of alternative fuels, energy credits and the most common, lower excise taxes on specific transportation fuels. This report looks at two of the most common: lower excise taxes and energy credits.

The existing lower excise taxes for natural gas used in a diesel engine should apply to a natural gas based F-T plant on the North Slope. If this is realized, the North Slope GTL plant would see a $13/bbl benefit.

ANGTL also believes that the Energy Credits granted coal and biomass based F-T plants in the 2005 Transportation Bill could easily apply to a natural gas based F-T plant. If true, then the Alaska GTL plant would receive over $21/bbl of price support with the combination of the lower excise tax and the tax credits. In addition, the $18 billion loan guarantee for the Alaska Gas Line may be able to apply to a GTL option so long as the transportation fuels are delivered to domestic markets. Finally, the National Defense Council Foundation report referenced at the end of this Section 8 clearly shows the hidden costs of importing crude oil and transportation products.

In 2003, the NDCF said, "*It would be difficult to imagine the advent of any commodity that has had the impact of oil on virtually every area of human endeavor. From transportation to medicine to agriculture to materials, petroleum-derived products have had a profound impact. Moreover, these products have been readily available at bargain-basement prices through most of our history.*" …… "*Yet, the price for a gallon of gasoline a consumer pays at the pump is in fact only a fraction of the real cost of the fuel. It does not reflect the enormous burden of external costs that arise from the military, economic, environmental and health outlays directly resulting from our dependence on foreign oil. If our nation is to make rational policy decisions regarding the rising tide of imports, it is essential that decision-makers fully understand what these costs are, and how they are incurred.*"

The Alaska delegation relied upon this report in part in marshalling support for the $18 billion loan guarantee. The facts contained in this report clearly show that Federal support for a domestic GTL, CTL or BTL program are justified far beyond the 31¢ to 50¢ per gallon we are proposing herein.

We would point out that there are more than enough federal support programs on the books to improve the economics of a North Slope GTL option. Some may require simple changes from a loan guarantee for the Alaska gas line to an Alaska GTL option, some may take an IRS written ruling saying "yes" GTL based F-T diesel is the same as CNG when used as a transportation fuel.

The bottom line is that the U.S. needs domestic transportation fuels and especially domestic refinery capacity more than it needs additional natural gas. A North Slope GTL program fits this need to a tee.

8.2 Introduction

There are many different programs of support for new energy projects that will add refining capacity and/or reduce the level of imported crude oil/transportation fuels. More are contained in Federal legislation passed over the last 35 years. They range from federal loan guarantees, grants, lower excise tax rates, accelerated depreciation of capital expenditures at existing refineries, accelerated depreciation of capital costs for new refinery capacity and mandatory requirements to use alternative fuels to either replace additives (MTBE's) or gasoline in vehicles. Most of these programs have sunset provisions requiring that they be renewed every 5 years, begun by a date certain or be place in commercial operation by a date certain. For this report we will look at federal excise tax support, the longest running of any of these support programs and the most likely form of support an Alaska North Slope GTL plant would receive. The Alaska Legislature should also note that the support we are discussing for the GTL option would or should apply to the coal to liquids (CTL) program ANRTL is proposing for the west side of the Cook Inlet near the Beluga coal fields.

8.3 Federal Excise Road Tax – One Way of Traditional Support for Alternative Fuels

In 1996, when Alaska Natural Gas To Liquids (ANGTL) first approached the State of Alaska, ARCO, BP and Exxon with the idea of a GTL plant we realized that some sort of price support for GTLs was needed if these ultra-clean products were going to receive the same price as petroleum based transport fuels at the pump. Despite American's talk about clean fuels the reality was that if most consumers had an option they would purchase the lower cost fuel even if it was worse for the environment. New refineries had to have a way to recover their capital cost at the pump whereas existing refineries had no capital cost component to recover. In general it was much cheaper for transportation fuel suppliers to import gasoline and diesel than to try to get approval to build a new refinery. Promoters of alternative fuels, which in general had a higher cost to recover at the pump, got around this issue on two fronts:

- First, they convinced Congress to enact laws requiring these alternative fuels be used despite their higher costs; and
- Second, they got Congress to provide a lower federal excise tax for that specific alternative transport fuels.

An example of this is ethanol. Certain states, at the urging of the Federal Government, enacted laws requiring the use of ethanol. Since ethanol could not be used in the existing infrastructure, nor at 100% in existing engines, the makers of ethanol came up with gasohol, a blend of 10% ethanol and 90% regular gasoline. In order to recover the higher costs of producing, transporting and distributing the alternative fuel, Congress instigated that gasohol sellers could keep 5.4¢ of the Federal Excise tax collected at the pump for each gallon of gasohol sold. While the "tax reduction" seems small in fact it actually amounts to 54¢/gallon for ethanol because of the blend ratio. Many States also enacted similar legislation rebating back to the gasohol producers a portion of the road tax charged at the pump. The key to collecting this tax was that the fuel had to be designated as an "alternative fuel" under the 1992 Environmental Protection Act (1992 EPACT). Other examples of alternative fuels that have a lower excise road tax are compressed natural gas (CNG), liquefied petroleum gas (LPG), liquid natural gas (LNG), propane and butane.

From the 1960s through 2006 these alternative fuels provided lower tail pipe emissions than conventional diesel and thus under the different Clean Cities programs enacted by Congress helped fleets meet lower and lower tail pipe emissions. Compressed Natural Gas (CNG) is a direct competitor of F-T diesel so we will look at this alternative fuel in greater depth.

CNG requires an expensive refueling station and the vehicle with a high pressure tank to store the CNG in. The special tank is heavy, puts more weight to the vehicle and load to the road. Because the energy density of natural gas is much lower than liquid diesel the range of CNG vehicles is much lower. This usually limits the application to vehicles that return to a central location each evening and to vehicles that do not travel more than 150 miles in any one trip.

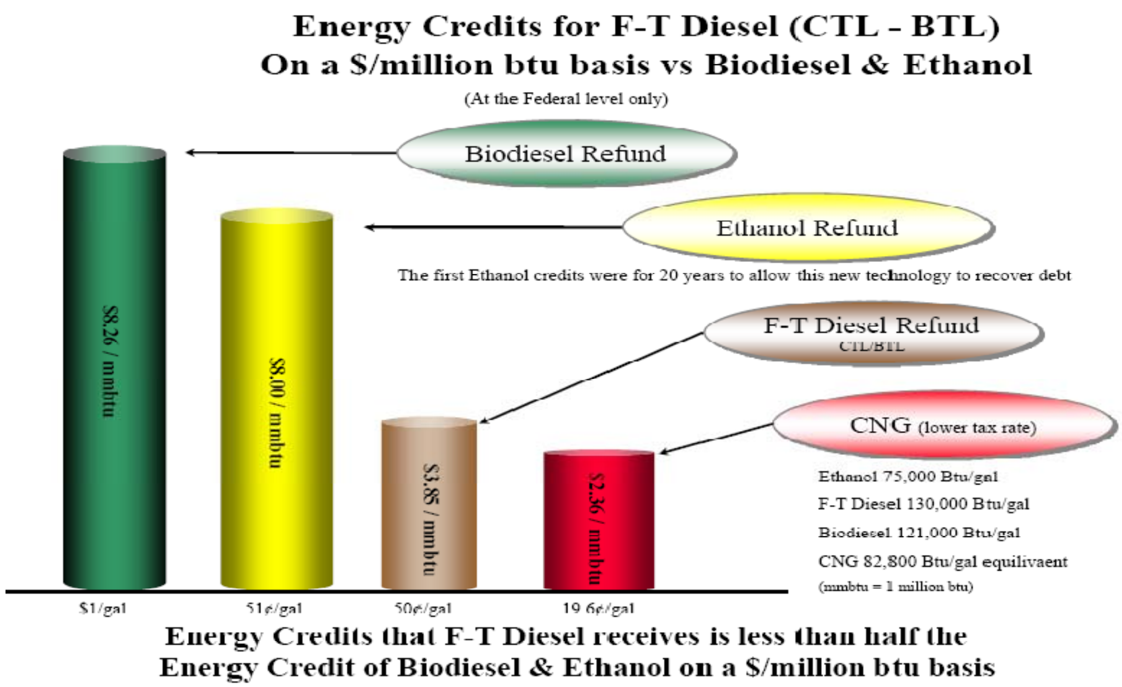
To recover the high initial installation/conversion costs Congress agreed that it would tax CNG at a much lower excise tax rate than conventional diesel. The federal excise tax on road diesel is 24.3¢/gallon whereas the federal excise tax on CNG is 4.7¢/ gallon. This is 19.6¢/gallon less ($8.23/bbl). Many states have adopted a similar lower excise road tax on alternative fuels. In particular California lowered its tax on CNG from 18¢ to 7¢ per gallon. Interestingly, California has a road tax permit program that lowers the tax on CNG to as low as 1¢/gallon, a 17¢/gallon savings. If one couples the two excise taxes, federal and state together, there is a savings of between 30.6¢ ($12.85/bbl) to 36.6¢ per gallon savings ($15.37/bbl). This tax saving allows for the alternative fuel supplier to sell the alternative fuel, CNG in this case at the fuel pump while recovering additional money to pay for the capital cost of the new fuel delivery system.

For F-T fuels to get an equivalent benefit, the first step needed was to get F-T fuel classified as an “alternative” fuel under the 1992 EPACT. This enabled F-T transport fuels to be taxed at a lower excise rate allowing F-T developers to recover a portion of the capital costs of these very expensive and complex plants. One would think this would be easy considering the tremendous environmental advantages of F-T diesel. However; there was a lot of opposition from the natural gas industry, the Department of Energy (DOE) and even from the major oil companies. It took the efforts of Alaska Congressman Don Young to introduce language that provided natural gas based F-T with this “alternative fuel” status in 2001.

ANGTL approached the IRS and asked the following question: “Given the fact that when natural gas (in the form of compressed natural gas - CNG), is consumed in a motor vehicle, it is taxed at a much lower rate than petroleum based diesel, would a transport fuel also derived from natural gas via the Fischer-Tropsch (F-T) process also qualify for the same lower tax rate”? In 1998, the IRS indicated that they saw no reason why GTL transport fuels made from natural gas should not also enjoy the same lower federal excise tax rate as CNG. The State of California said they concurred with the IRS on this point. Thus F-T diesel when sold at the pump at the same price as petroleum based diesel would receive a 31¢/gallon “premium” or $13/bbl.

Please note that this lower excise tax rate for F-T diesel made from natural gas did not apply to F-T fuels made from coal or biomass. ANGTL then went to Congress to seek support for F-T fuels regardless whether they were made from coal or biomass. Through the support of the Alaska delegation and in particular, Senator Ted Stevens, language was placed in the 2005, Transportation Bill, approved by Congress in August of 2005 and signed into law by President Bush in September 2005, granting energy credits similar to those approved for ethanol and biodiesel. The credits for F-T transportation fuels equaled 50¢/gallon or $21/bbl for F-T fuels made from coal and biomass.

ANGTL did not ask that these credits also apply to F-T transport products made from natural gas because the State of Alaska did not support a GTL option for the North Slope. It should, however, be a simple modification of the existing language to include F-T fuels made from natural gas. Thus, when one looks at the netback for F-T fuels sold in California (each state has a different excise tax rate rules allowing for reduced taxes) a minimum of 31¢/gallon to the wholesale price to potentially as much as 50¢/gallon can be added. It should be kept in mind that the 50¢/gallon Energy Credit is only on the Federal excise tax. California has indicated that they will also provide a lower excise tax rate on F-T diesel sold in California but for this report we have assumed this to be at zero value.



The chart above shows the relative cost on a Btu basis for the energy credits (lower excise tax rate) provided to CNG, F-T diesel, biodiesel and ethanol. *Note that this chart is only showing the excise tax rebate on the federal level*. The price at the gas pump includes the refinery wholesale rack price, the transportation costs from the refinery to the gas station, a profit for the gas station along with federal, state and local taxes included. Typically both the state and federal government provide a lower tax rate for these clean burning alternative transportation fuels and in some cases the local taxing authority also provides for a lower tax rate. In our example we use both the federal and state (California) lower transportation excise tax rate applied to CNG (the 31¢/gallon tax savings); however, for the 50¢/gallon energy credit we are only using the federal tax savings.

According to Senator Lisa Murkowski, Congress enacted a Federal Loan guarantee, up to $18 billion for the Alaska Gas Pipeline partially based partly upon the 2003 National Defense Council Foundation report America's Achilles Heel – The Hidden Cost of Imported Oil – A Strategy for Energy Independence[1]. Some believe that this loan guarantee should be applied to the North Slope GTL option.

In the past, Governor Tony Knowles along with Senator Frank Murkowski, and then again as Governor opposed a GTL option over a gas pipeline. ANGTL believes that a GTL option has more benefits for America/Alaska and could result in a higher net back for Alaska natural gas than a gas line. It is possible that in addition to the lower excise tax, the "gas line" loan guarantee may apply. If so, it would reduce the finance costs of the GTL option, further improving the net back price of the natural gas. Adding U.S. new or incremental refining capacity should be a priority of Congress. It is very possible that Congress will extend the accelerated depreciation allowance provided in the 2005 Energy Bill to GTL/CTL projects in the future as they address two important issues:

- Reducing U.S. dependence on imported crude oil and transportation products.
- Add U.S. refining capacity to meet the domestic demand for transportation fuels.

Both of these points will reduce or slow the increase in costs of crude oil and refined transportation products in the future. In addition, adding domestic refining capacity will reduce the current high margins enjoyed by refiners resulting in a lower price at the pump. At some point Congress will have to embrace GTL, CTL and BTL plants as elements of the few potential programs that can utilize existing U.S. domestic resources to reduce and or eliminate our dependence upon imported energy, especially OPEC oil. As pointed out in the NDCF Report, the true hidden costs of imported oil at the fuel pump could be well over $2.50/gallon above the actual pump price. If Congress ever gets to the point of adopting a National Energy Policy to help insure U.S. National security, the level of Federal support will increase dramatically for domestic F-T plants such as the North Slope GTL plant discussed in this report. The American people at some point will realize that incremental fuel production and refinery capacity has to be the basis of a future energy policy. Alaska has all the possibilities to lead the way.

8.4 No new federal programs needed for support of a North Slope GTL program

Given the record profits oil companies are making today and the record tax revenues Alaska is receiving there is concern that Congress will enact any legislation to help Alaska to develop its North Slope gas resources. We would point out that there are more than enough federal support programs on the books to improve the economics of a GTL option. Some may require simple changes from supporting a gas line to a GTL option, some may take an IRS written ruling saying "yes" GTL based F-T diesel is the same as CNG when used as a transportation fuel. The bottom line is that the U.S. needs domestic transportation fuels and especially domestic refinery capacity more than it needs additional natural gas. A North Slope GTL program fits this need.

References:

1) *National Defense Council Foundation "America's Achilles Heel: The Hidden Costs Of 1Imported Oil – A Strategy for Energy Independence"* 1220 King Street ■ Suite #1 ■ Alexandria, VA 22314 ■ (703) 836-5402 ■ Email Address: **ndcf@erols.com** ■ Web Address: **www.ndcf.org.**

9 ECONOMICS OF A NORTH SLOPE GTL OPTION

9.1 Summary/Conclusions

We have evaluated a 450,000 bbl/d North Slope GTL option under two different scenarios: (1), construction in one large scale project beginning in 2009; and (2) a phased construction consisting of five (5) 90,000 bbl/d modules beginning in 2009 and concluding in 2022. The total capital cost, approximately $40 billion is about the same for each case due to our projected cost of inflation of 3% per year.

The initial cost per installed barrel of capacity was determined for the recently completed 34,000 bbl/d Sasol ORYX GTL plant built in Qatar. Based upon current demands for men and materials we estimate that the costs for new GTL facilities has escalated from $35,000 per daily barrel for the just-completed Sasol ORYX GTL project to $60,000 per daily barrel. Such has been validated for modules of 70,000 bbl/d to 80,000 bbl/d capacity. This modular approach has been applied by Shell in Qatar for their Pearl project and within reason makes complete sense for any application on the Alaska North Slope.

The $60,000 per daily barrel cost is the result of the tremendous increases in cost for new energy projects across the world. It is generally accepted in the energy world that such escalation is an over-reaction forced by constraints in materials availability and engineering capacity. It is felt that this escalation will re-dress itself in the next few years; however, it is unlikely that we will return to the $25,000 per daily barrel we had seen for the Sasol/QPC ORYX project in 2002. A level of $50,000 per daily barrel is seen as a likely future scenario.

North Slope Location Factor of 1.5

For a preliminary cost estimate, taking into account the location and environmental conditions on the North Slope, we have applied a location factor of 1.5 x $50,000/installed barrel of capacity, implying the use of $75,000 per daily barrel. Thus a 450,000 bbl/d facility would cost an estimated U.S. $33.8 billion on a 2007 dollar basis. Assuming a modular construction of one of five 90,000 bbl/d units every other year after 2014, the first product from module # 1 some 6 years from today and an annual inflation of 3 % the escalated total investment upon completion of the project in year 2022 would amount to some **U.S. $40.5 billion**. Interestingly, we estimate that a single build GTL plant of the same capacity would cost the same as the phased building because the lower cost of future modules will offset the cost of inflation.

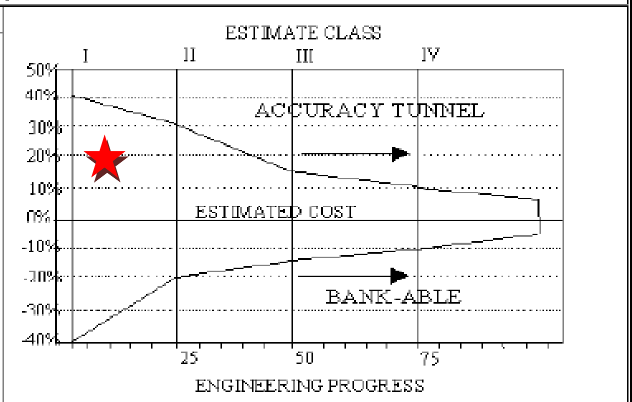
There are advantages and disadvantages to phased construction that are covered in more detail in Section 12.

We estimate based upon a 25% equity investment with a 20% IRR, a 20 year bank loan at 7.5%, a $7/bbl transport cost from Prudhoe Bay to California markets and wholesale diesel prices in the $3.20/gallon range that the net back to North Slope gas suppliers at the GTL plant inlet will be in the $9.10/MMBtu range.

We did not include the economic advantages of a phased construction for Alaska business, the fact that 100% of the CAPEX will be in Alaska, that a GTL plant will be a net exporter of energy, i.e. will produce excess energy to operate other North Slope operations, the TAPS line would operate more efficiently with a lower tariff, nor did we assume any price advantage for shipping NGLs down the TAPS line to Valdez over the sale of the same NGLs in central Alberta.

Finally, the general way to evaluate the costs of a major project is to do it in discrete phases. Each phase evaluates the costs of various aspects of the project in more detail until you arrive at the end of the "accuracy tunnel" at a +- of 5%. It is at this point that a final go – no go decision is made and the project developer requests bids for an engineering, procurement and construction contract or EPC contract. This final step provides the developer with one last check on the economics of the proposed project.

The North Slope GTL option would be in the first phase of its evaluation, I Preliminary Feasibility Study (see chart below). Normally you would say that the costs estimates are a +- 40%. However, with the recent building of the Sasol ORYX GTL plant and the start of engineering of the Shell Pearl GTL facility we believe that the costs estimates used herein are more likely to be at the + 20% level and that further evaluation will result in a lower cost estimate. When the reader notes that the Alaska GTL plant is estimated to cost 300% more per installed barrel of capacity than the just completed Sasol ORYX GTL plant we believe you will agree with our statement.

MINIMUM INFORMATION REQUIRED TO DEVELOP ESTIMATES					
ESTIMATE CLASS	I	II	III	IV	
ESTIMATE TYPE	PRELIMINARY FEASIBILITY	FEASIBILITY BANKABLE	DEFINITIVE	DETAILED	
ACCURACY RANGE	+40% To -40%	+30% To -20%	+15% To -15%	+10% To -10%	X = Info Required to Obtain Stated Accuracy Range
PURPOSE	Screen	Study	AFE	AFE	
GENERAL PROJECT SCOPE	X	X	X	X	Project Scope, Design Basis, and Execution Strategy
	X	X	X	X	General Geographic location and Site Requirements
	X	X	X	X	Special Considerations that Impact Project Costs
	X	X	X	X	Utilities and Other Infrastructure Requirements
			X	X	Detailed Project Schedule
PROCESS	X	X	X	X	Block Flow Diagrams w/Primary Flow Steams and Utilities
		X	X	X	Preliminary PFDs w/Heat & Material Balance
		X	X	X	Engineered PFDs w/Heat & Material Balance, and Preliminary P&IDs
			X	X	Engineered P&IDs

When one considers that:

- two of the North Slope gas owners, ConocoPhillips and ExxonMobil have agreed to build world scale GTL plants in Qatar;
- Chevron, Sasol's world wide GTL partner is a major player in the Point Thompson field; and
- BP is working with Statoil to develop barge mounted GTL plants

The technical knowhow is there to develop an economic North Slope GTL program.

9.2 Net Back to the GTL Plant Inlet at Prudhoe Bay

Determining the netback from the market to the GTL plant inlet involves many assumptions. It is not the purpose of this report to refine the relative costs of each to an Engineering Procurement Contract (EPC) level. Section 9 below provides an analysis of what we believe the costs of a GTL option for the North Slope would be.

Realizing that the equipment for the ORYX plant was ordered prior to the tremendous increase in costs for new energy projects across the world we escalated the costs for world-scale (70,000 bbl/d-90,000 bbl/d) to a 2007 basis, still a Qatar location and needed to adjusted these costs to over $60,000/installed barrel.

It is generally believed in the energy world that the recent cost escalation is an over-reaction forced by constraints in materials availability and engineering capacity. It is felt that escalation will redress itself. However, we do not see a return to $35,000/daily barrel for a plant like the ORYX. A level of $50,000/ daily barrel is seen as more likely. To this we applied a location factor for Alaska of 1.5, taking into account that many of the modules for the plant would not be built on the North Slope, but that civil and labor cost on the North Slope is substantially higher. With the assumptions that:

1) The future maximum single module size for GTL plants will most likely be 90,000 bbl/d
2) A first module could be commissioned on the North Slope in 2014
3) Additional 90,000 bbl/d modules, up to a total of 450,000 bbl/d capacity will be added every other year
4) The first module will carry much of the costs of infrastructure (buildings, like a control room, maintenance shop, tank farm, etc.), leading to an effective cost reduction of subsequent modules, assumed to be (2007, Qatar cost basis) $92,000/daily bbl, $88,000/daily bbl, $87,000/daily bbl, $88,000/daily bbl and $93,000/daily bbl for module 1,2,3,4 and 5 respectively.
5) Inflation at 3% per year

We arrived at an installed cost in 2014 of around $ 92,000/installed barrel, some 300% above the actual cost of the just-completed ORYX plant. We believe the numbers for the North Slope modules, presented below, are conservative, however.

Plant	ORYX	Pearl	**Module 1**	**Module 2**	**Module 3**	**Module 4**	**Module 5**	AK SUM
Location	Qatar	Qatar	Alaska N-Slope	Alaska N-Slope	Alaska N-Slope	Alaska N-Slope	Alaska N-Slope	
Capacity (bbl/d)	34,000	140,000	90,000	90,000	90,000	90,000	90,000	450,000
Year	2007	2007	2014	2016	2018	2020	2022	
$/daily bbl	$35,294	$64,286	$50,000	$45,000	$42,000	$40,000	$40,000	
Location factor	1	1	1.5	1.5	1.5	1.5	1.5	
Inflation factor	1	1	1.23	1.30	1.38	1.47	1.56	
Capital $ millions	$1,200	$9,000	$8,302	$7,926	$7,849	$7,930	$8,413	$40,420
Actual $/daily bbl			$92,241	$88,072	$87,207	$88,112	$93,478	$89,822

9.3 Putting the costs of GTL in perspective

The economics of a GTL technology scheme or project should reflect our interest in: (1) Does it make money, and if so, (2) how much does it make?…and, (3) what is the return on investment?

The answer to those questions should be based on unambiguous facts on the revenue streams and costs. Therefore, one would expect the economics of GTL plants to receive the obvious attention as a key parameter in judging the technology and its viability.

Regarding the revenue streams, the publicly accessible, predominantly fuel market, in which the GTL industry plays, provides reasonably transparent information, although at times the question of product premium comes up.

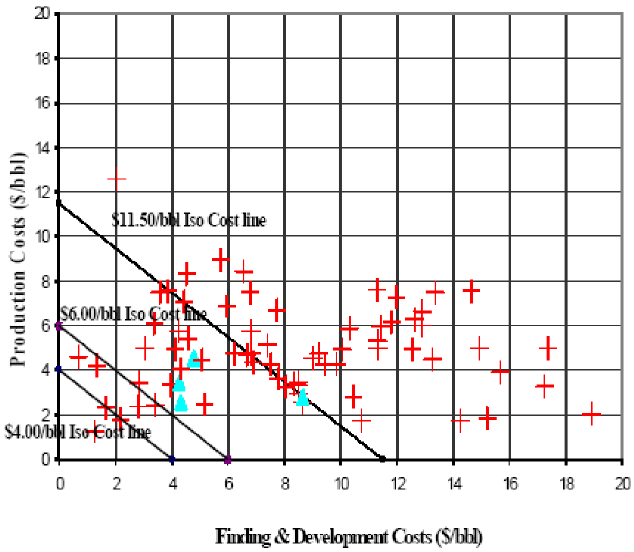
On the cost side, the picture of unambiguous facts and information is completely different.

In fact, there is fairly little substantive material published on the subject, which may stem from the fact that,

1. the F-T technology is not (yet) widely practiced and there is simply **not sufficient reference material**; and/or
2. the projects deal with remote gas at **very different locations** in the world without a common denominator or transparent location factor; as well as
3. technology suppliers are **selling** (pieces of) technology, not overall project profits; and/or
4. much of the economic data are based in **proprietary** developed databases (which the owners obviously really do not want to share).

One way of looking at a GTL plant is for the owner of the GTL installation to see the facility as a tool to create oil as a complementary way of finding oil. This view can therefore project a ceiling for the costs of being able to exploit natural gas reserves (or other synthesis feedstock for that matter) and of making GTL products, while the alternative is the cost of finding a barrel of oil the conventional way.

Compiling a list of exploration and production costs for the largest oil and gas companies is somewhat like comparing apples and oranges. The various companies operate differently and one can question about whether we are talking about oil, or gas, or both, or oil equivalent. In an attempt to shed at least some light on the subject, we have taken available data on E&P spending costs, starting with 2002 data, as reflected in the John S. Herolds 2003 report [1], in a first attempt to look at data before the oil price increases, which happened after oil passed the $50–$60 per barrel benchmark. This gives rise to the following figure:



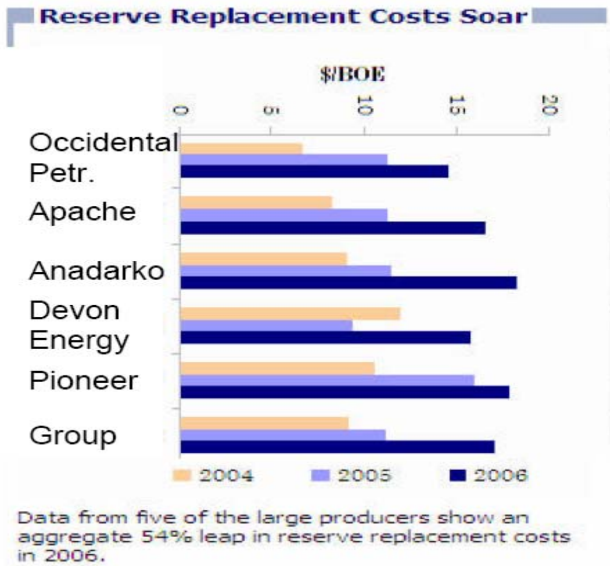
In the graph above, completed in 2003, four well-known GTL technology providers are, without further identification, noted with blue triangles. They are in the U.S. $6.50–$11.00 per barrel range of exploration and production costs. To check consistency in time, we followed the aforementioned up and, using available data of 2003[2], divided Exploration & Production (E&P) spending costs by the annual production to obtain an estimated E&P spending per barrel. See table below.

COMPANY	WORLDWIDE OIL PRODUCTION Million barrels per year, 2003	Est. E&P Spending, 2003 Million U.S. $$	Est. E&P Spending per barrel U.S. $$
BP plc	1.284	$8,599	6.7
Exxon Mobil	1,586	$11,082	7.0
Royal Dutch/Shell	1.406	$9,949	7.1
Chevron Texaco	921	$5,176	5.6

This should be seen in light of the old “rule of thumb,” being:

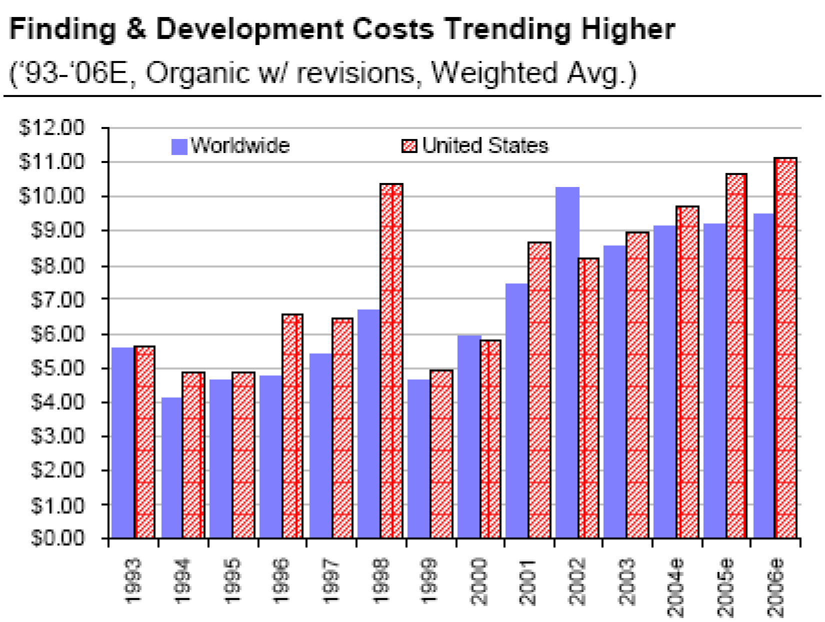
“Cheap oil is produced in the Middle East at roughly U.S. $1.00/barrel E&P spending” and “After the Energy Crisis of 1973, we were ready to spend up to U.S. $5.00 per barrel.”

The 2002 and 2003 data show that the oil companies with F-T technology in common have “replacement cost of oil” are in the order of U.S. $6.00–$8.00 per barrel, while spikes as high as U.S. $10.00 do not seem unusual. Other large to mid-size companies show even higher numbers. It gets worse if cost escalations in (mainly in drilling) the most recent years are taken into account. Some believe that 2006 costs will be at the highest. The graph below shows most recent data of some U.S. companies, which are active in the U.S. Gulf and have seen the costs of the hurricanes of 2005 come through in 2006:



Source: J.S. Herold Inc (2007)

Also Morgan Stanley's research points in the direction of rising costs for finding and development of oil (and gas).



Companies included: APA, APC, BR, CHK, DVN, EOG, FST, KMG, NBL, PPP, PXD, UCL, XTO

Source: Morgan Stanley Equity Research Estimate

To put this in perspective, at the official ground-breaking of the Pearl project, Shell Chief Executive Jeroen van der Veer was questioned about the project and its costs. He said that Shell had an advantage over other competitors because of the GTL plant in Malaysia it has operated since 1993. "For us, GTL is proven technology," he told reporters in Qatar. He said the project remained inside its development-cost estimates of U.S. $4 to U.S. $6 per oil-equivalent barrel of production over a period of time. Based on that, total project costs have been pegged as high as $18 billion assuming an estimated lifetime-output of about three billion barrels of oil equivalent. A Shell spokesman said that (the $4 to $6 per oil equivalent barrel) is comparable to other big exploration and production projects it undertakes. [3] When we do our mathematics on the above (assuming 140,000 bbl/d F-T output as well as 120,000 bbl/d of condensate, or 300,000 bbl/d oil-equivalents), the U.S. $18 billion and U.S. $6 per barrel translate in a "period of time" of about 25 years. All in all, the numbers are not too far away from the replacement cost of crude-oil that seem acceptable to Shell. Does that mean that we have found a new yardstick—at least a ceiling—for GTL projects? In the case of Shell's Pearl project the escalated costs for the GTL plant itself are estimated at U.S. $ 9 billion. In our estimate, of the 80 % cost increase, 40% can be contributed to cost increase of materials, 10 % due to engineering cost increase and 30 % due to the loss in value of the dollar to predominantly the Euro, but also to other currencies.

Obviously there are in many cases various alternatives which a company has to "replace oil," among which there are acquisition of other companies and/or their reserves, or there might be different projects offering a more attractive alternative. ExxonMobil's decision to pursue the development of the Barzan Project in Qatar's North Field, instead of the Palm GTL project, may well fall in the latter category. Spurred by cost discipline, an area in which ExxonMobil's management has had an excellent track record, exploitation of the Barzan gas may well yield a more cost effective "oil replacement" than the Palm GTL project, of which the costs in an early stage are said to have already exceeded U.S.$9 billion.

9.4 GTL Cost Expressed in Dollars per Daily Barrel

Most of the reviewers of GTL economics have accepted the **production cost per daily barrel** as the best way of capturing GTL plant costs and use it as the yardstick for comparison.

Although such numbers are sometimes used for advantageous commercial purposes it needs to be said that the production cost per daily barrel could be a true instrument for comparison, **provided everyone uses a similar basis and includes the same elements.** Failure to do so, and that is the true and fundamental ground for concern, leads to "comparing apples with oranges."

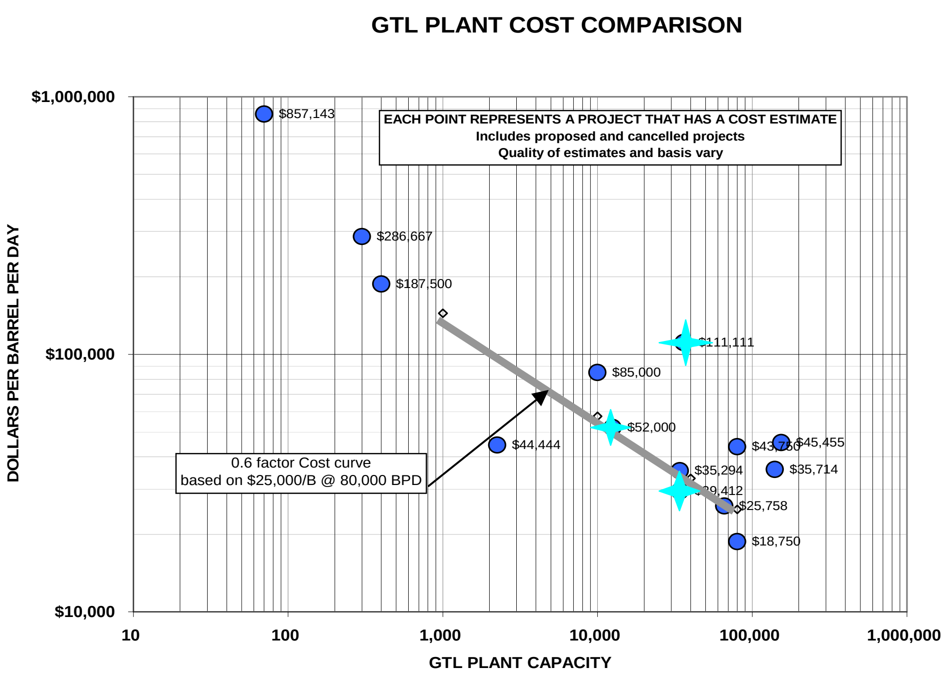
These "apples and oranges" occur both in the nominator (the costs) and in the denominator (the barrels) of the cost equation: in the cost number, one finds that the cost of the F-T plants—meaning solely the cost of the production units (Feed gas conditioning/Syngas manufacture/Oxygen plants/Syngas conditioning/Syngas compression / F-T reactor section / distillation & hydro-cracking / isomerization), also called inside battery limit—is sometimes confused with the cost of the total facility or of the total project (see the Shell numbers above and the comments in the table below). In the barrels, one needs to distinguish between barrels of C_5^+ (pentane and higher) or C_3^+ propane and higher.

To illustrate the latter, let us look at the available data where information which can be more or less substantiated, has been presented and is not of the "times $30,000 per daily barrel" type (the cut-off point of data gathering was clearly before ExxonMobil pulled out):

		BBL/D	MM DOLLARS	DOLLARS/DAILY BBL	YEAR	
SYNTROLEUM	CATOOSA	70	$60.0	$857,143	2002	Demonstration
CONOCOPHILLIPS	TULSA	400	$75.0	$187,500	2000	Demo - 2*CPOx
						2 FT's /1 HCU
WGTL/PETROTRIN	TRINIDAD	2,250	$100.0	$44,444	2005	Re-utilized equipment &
						Refinery integration
BP	NIKISKI	300	$86.0	$286,667	2000	Demo- only syncrude &
						no distillation
SHELL	MALAYSIA	12,500	$650.0	$52,000	1994	Operating-revamped
SYNTROLEUM	AUSTRALIA	10,000	$850.0	$85,000	2001	Cancelled
SASOL (Oryx)	RAS LAFAN	34,000	$1,000.0	$29,412	2005	s/u early 2007
SASOL/CHEVRON	NIGERIA	34,000	$1,200.0	$35,294	2005	Under Construction
SASOL	RAS LAFAN	66,000	$1,700.0	$25,758	2003	proposed
SASOL	RAS LAFAN	130,000	$4,500.0	$34,615	2003	proposed
ConocoPhillips	RAS LAFAN	80,000	$1,500.0	$18,750	2003	Feasibility Study
ConocoPhillips	RAS LAFAN	80,000	$3,500.0	$43,750	2003	Feasibility Study
MOSSGAS	GEORGE	36,000	$4,000.0	$111,111	1992	10,000 bbl/d
						Condensate
SHELL	RAS LAFAN	140,000	$5,000.0	$35,714	2003	Under Construction
EXXONMOBIL	RAS LAFAN	154,000	$7,000.0	$45,455	2006	Feasibility Study

Public data on existing, announced and cancelled F-T projects [4]

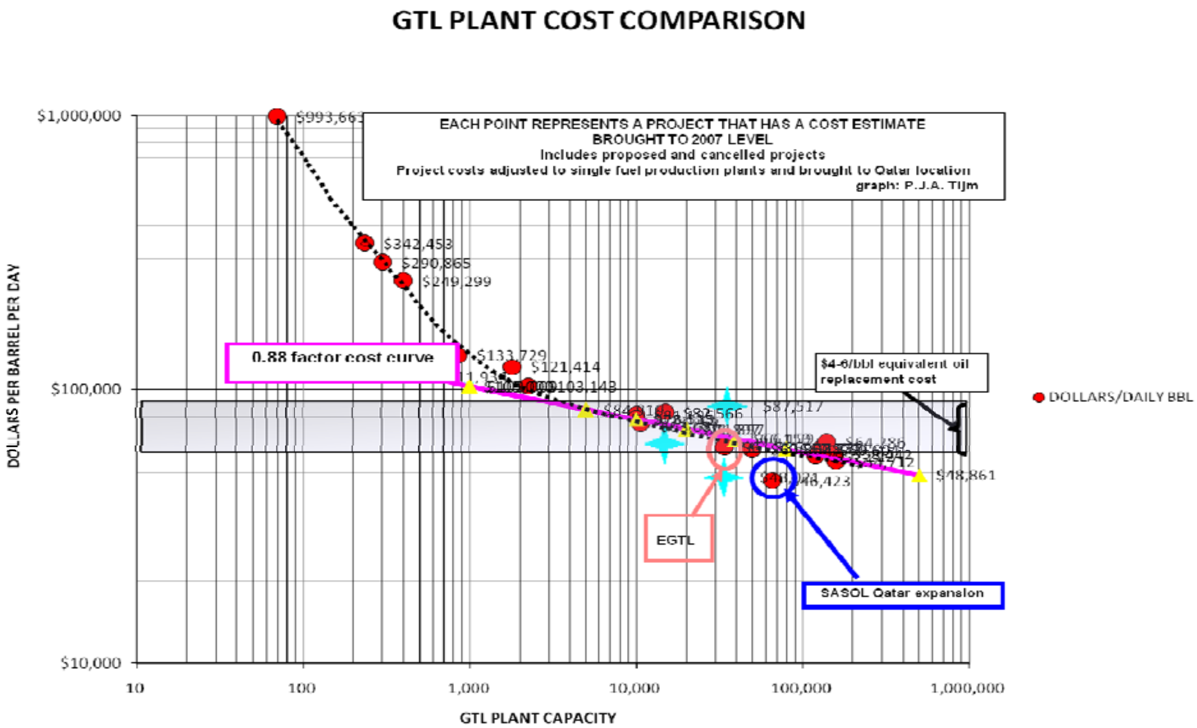
On a historic basis, the following graph is obtained (showing a 0.6 factor cost-line):



The stars in the above graph represent the existing GTL facilities: the 15,000 bbl/d Shell Bintulu, Malaysia, the 36,000 bbl/d PetroSA, George, South Africa and the 34,000 bbl/d Sasol/QPC Ras Laffan, Qatar facilities.

However, with the realization of the time value of money and knowledge of the differences in design basis of the various projects, the authors [5] have made some (experience-based) corrections. For example the outputs of plants has been adjusted to reflect comparable fuels production facilities and, likewise, project costs have been corrected to a Qatar location factor. Additionally, the author [5] has various other datasets available, including several PEP reports by SRI Consulting. The set of 22 data points results in the figure below.

The results of "massaging" the numbers is actually very revealing in terms of the economy of scale. The concept of Economy of Scale is based on the established facts of project execution that doubling the size of a 100% unit to 200% does not cause the total installed cost to double. Typically, when vessels, etc. can be increased in diameter, the cost rises by an exponent of about 0.6; when doubling the size, this results in a cost increase by a factor of 1.5. The economy of scale is what drives project developers to build large single stream units wherever feasible. The graph below shows that scale enlargement up to 15,000 bbl/d to 17,000 bbl/d plants is beneficial, i.e. the costs per installed barrel drop relatively fast. The results of "massaging" the numbers for the larger facilities, like the Shell Pearl project and ExxonMobil's proposed plant still show an economy of scale, albeit much less pronounced. Economists would say that the costs reduce with an exponent of almost 0.9 rather than the usual 0.6–0.7, so we are very close to linear scale-up. We understand such data, as we consider that for those super large plants the costs of process units basically scale linearly since capacity increase can only be obtained by multiplication of the number of units. Only few process facilities, like distillation sections, the hydrocracker, and common facilities, like control room, utilities, tank farm, etc. still have economy of scale.



Also interesting to observe are the advantages of "strategic cost planning": The "first mover" advantage for the Sasol/Chevron Nigeria (EGTL) plant (shown above) was originally clearly visible, just as the blue star below it for the ORYX project in Qatar. The cost advantages for the Nigeria plant, however, are rapidly disappearing as the plants' start-up is seriously delayed and costs are rising: for EGTL the above graph already reflects a recent EGTL cost-estimate of U.S.

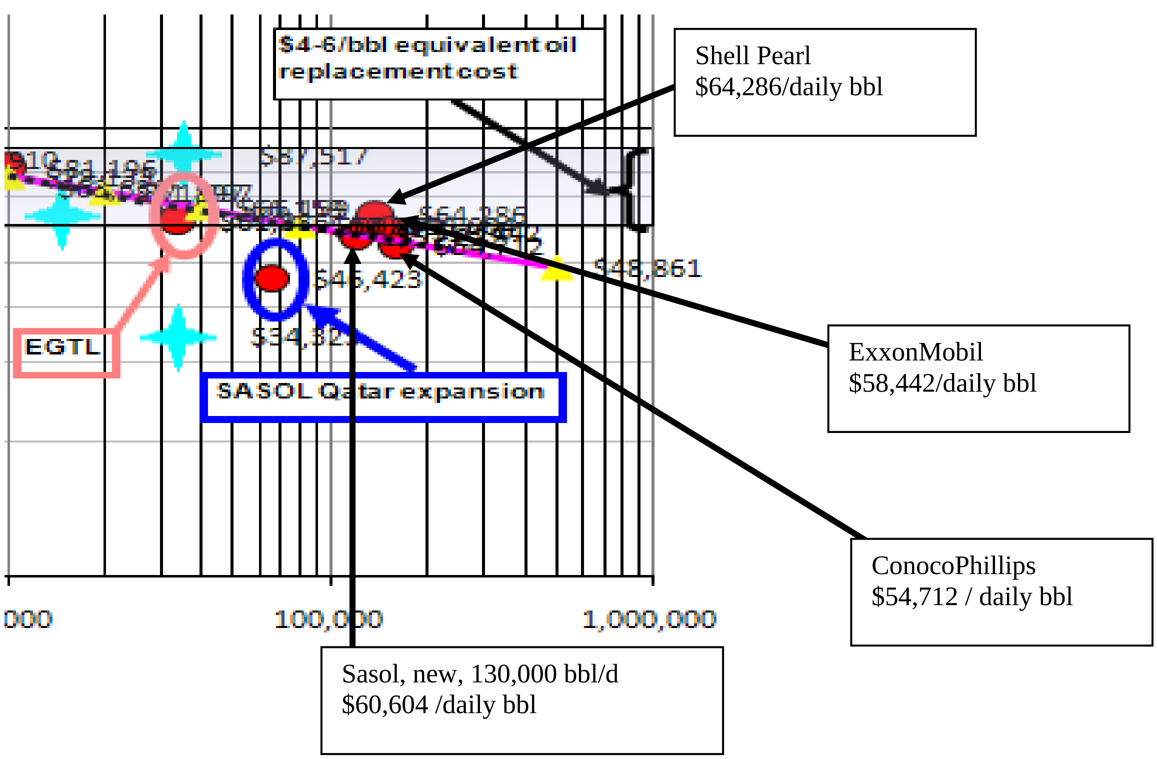
$2.5 billion (2007 estimate). Very striking is the "brown-field expansion" advantage of the Sasol/QPC (ORYX) expansion 1.

Finally, the graph shows that all the larger proposed GTL facilities in Qatar are basically on par in terms of cost, irrespective of whether conventional, slurry or CPOx technology is used. Yet, all projects are in terms of dollars per barrel at the bottom of the margin acceptable for Shell as "replacement value for oil." It shows that Shell has used their GTL experience to their benefit and—even though the costs have hit the Pearl project hard—they manage to get cost reduction for their larger plant.

It gets even more interesting when the above graph is enlarged to a scale where the "large scale" projects can be more clearly distinguished. With some wishful thinking, one could draw the conclusion that:

- ConocoPhillips with Catalytic Partial Oxidation (CPOx) and slurry bed have the lowest $/daily bbl cost,
- Shell, with the traditional technology is the most expensive,
- Sasol sees the benefit of their brown-field slurry bed technology (is slightly below the curve) and
- Exxon Mobil is right on target and in the center,
  but then…

Please remember that we are looking at only some 15% cost difference between the competitors, and we know that Shell's technology is proven.



In the latter part of this section, we would like to present economics of (various part of) the F-T technology as solid figures, the facts with a narrative of and considerations around the parts and pieces with philosophy and background.

9.5 Cost Elements Discussed in More Detail

In the following, we will in more detail describe the relevant aspects of the main cost elements that influence the cost of a GTL scheme:

1. Natural Gas Price
2. Capital Cost
3. Catalyst Costs
4. Operating Cost (labor, chemicals, maintenance)

9.5.1 Natural Gas Price

Starting with our feedstock, natural gas, we may remark that natural gas sold as LNG will earn the natural gas consumption price, and natural gas used for GTL will earn the diesel, or more generally, middle distillate product prices. A chemical engineer can make a carbon mass balance and calculate how many methane molecules from a natural gas stream it takes to produce a barrel of F-T product. For all practical purposes, we will assume here that methane is the main constituent in natural gas (95% is generally a good assumption). Natural gas is not sold per molecule, but per volume or per unit of heat that the molecules generate upon combustion: it is often sold in dollars per million of British Thermal Units (MMBtu). Since we know the heat of combustion of a molecule of methane, we can thus calculate the relation between MMBtu of natural gas and barrels of F-T product: A good "rule of thumb" is roughly 10 MMBtu per barrel of F-T product. That said, second and third generation GTL/CTL such as Sasol and Shell are closer to 8 MMBtu per barrel of F-T product.

In other words, it takes quite a number of Btus or quite a volume of gas to produce a barrel of F-T product. Therefore, there is an important cost multiplier connected to the gas price, which is embedded in the cost of the end product. This leads to the notion that the GTL process needs reasonably priced (some say low-cost) natural gas in order for the F-T product to compete with crude oil derived products. A simple example can make this comparison with diesel transportation fuel clear: If natural gas for the F-T process is priced at U.S. $1.00 per MMBtus (10 cents/therm) the diesel produced needs to be able to be sold at a value of U.S. $10.00 per barrel, or some 25 cents per gallon, in order to recover only the feed gas cost. Of course, in addition to feed gas costs, there is labor, maintenance, catalyst and chemicals costs that need to be recovered as part of the out-of-pocket expenses, which combined with capital expenses and profit should give a marketable product.

When "stranded gas" is concerned, the cost of natural gas to supply either a GTL or LNG facility is negotiated between the gas owners and the investors, and likely has little relationship to observed market prices because the available alternative is not to sell the gas in consuming markets, but to leave it undeveloped or in some places flare it off. However, in consuming nations with an established price of natural gas, the choice for the gas supplier is not difficult: rather than processing and converting the natural gas, it is almost always more attractive to sell the gas directly into the market. As a result, we would suggest that we will never see a commercial GTL plant being operational in the Lower 48 States of the USA, in Europe or other regions with a developed gas infrastructure and market. They are appropriate for large gas deposits in remote locations, however. High energy prices or special "niche markets" may obviously make a difference.

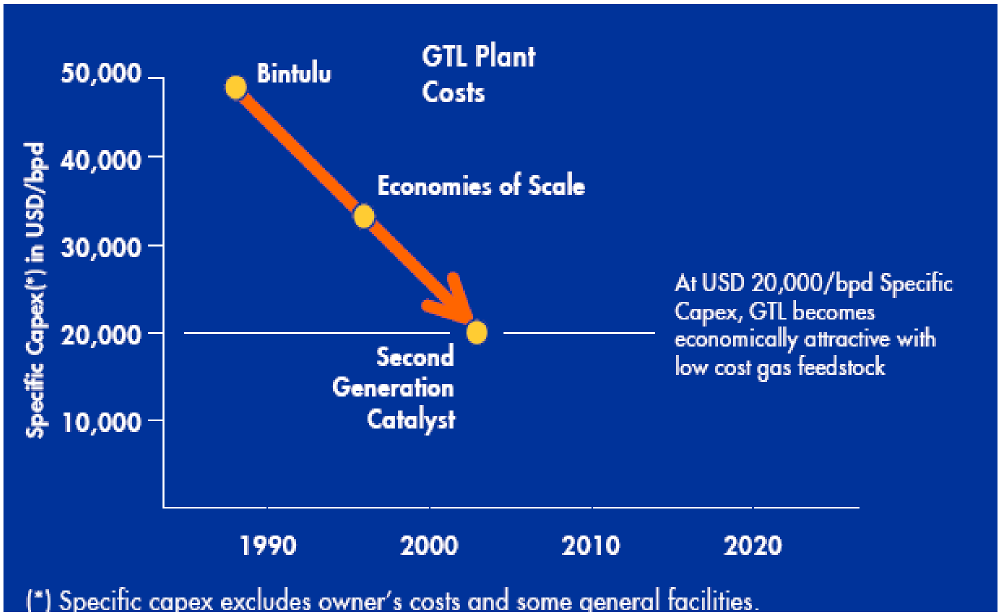
9.5.2. Capital Costs in Perspective

A second important and key determinant to the profitability of new GTL facilities is the cost of capital involved. The costs associated with integrated GTL projects are typically in the range of billions of U.S. dollars. Such large investment decisions require clear economic incentives and drivers. Availability of and competition for capital are the key factors in the costs associated with such large investments. The first GTL project ever financed and syndicated for raising the capital was the SASOL/QPC ORYX project, where Deutsche Bank led a consortium of fifteen lead arrangers and syndicated to six more banks. Following close scrutiny by lenders and their technical advisors, a project finance package of U.S. $700 million closed in January 2003 at attractive interest rates. This deal was awarded Middle East Project Finance "deal of the year" by the two most highly regarded publications in the world of project finance, *Project Finance International* and *Project Finance Magazine*, who select each year "Deals of the Year" based on their complexity and importance in regional categories.[6]

Although it is important how the financial burden is carried, in this section we will not venture into the intricacies of the cost of capital when it is leveraged by financing.

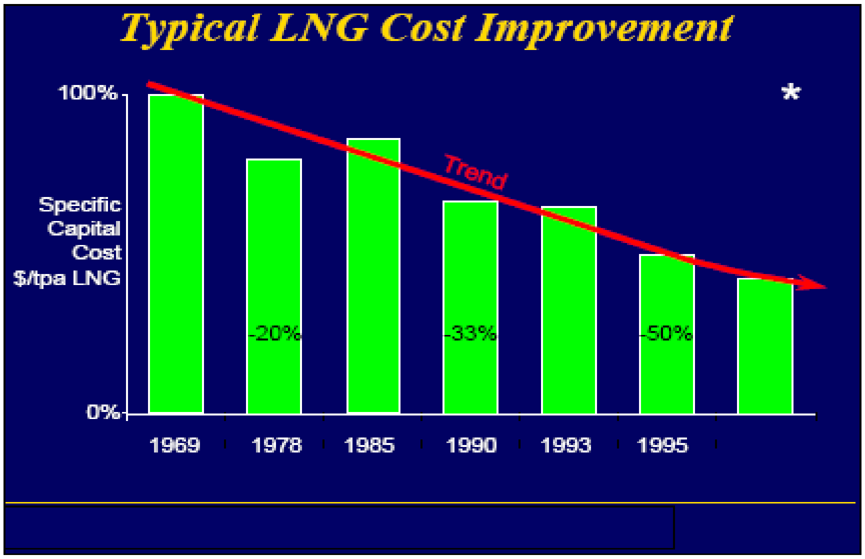
Instead, we will simplify this matter by simply looking at the capital cost. We have seen above that historically, before the ORYX plant came on stream, capital costs for GTL plants have been in excess of U.S. $50,000/bbl (total installed costs). In 2003, Shell [7] asserted that the capital expenditures for a new GTL facility might decline from U.S. $50,000 per barrel to U.S. $20,000 per barrel as a result of scale economies consistent with improved technology. One might note the caveat, included in the Shell slide:

> "Specific capex excludes owner's costs and some general facilities."



Courtesy: Shell [7]

As shown in the above figure, a large reduction is attributed to the "second generation catalyst." The latter is the catalyst, which, among others, allowed the capacity of the Shell Bintulu plant to be increased from 12,500 bbl/d to 15,000 bbl/d. Such predictions are supported by the extensive Shell experience with LNG cost development, which was subject of earlier presentations (Rob Klein Nagelvoort, Ed Stanton and Peter Tijm of Shell [8] [9] [10]).



* Source: Klein Nagelvoort, R., et al. [8]

Sasol, based on their extensive development in the Sasol reactor technology and its scale-up, demonstrated similar experiences:

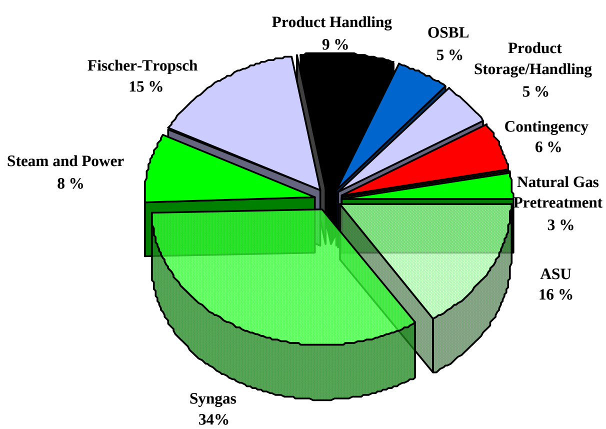
Source: Sasol [6]

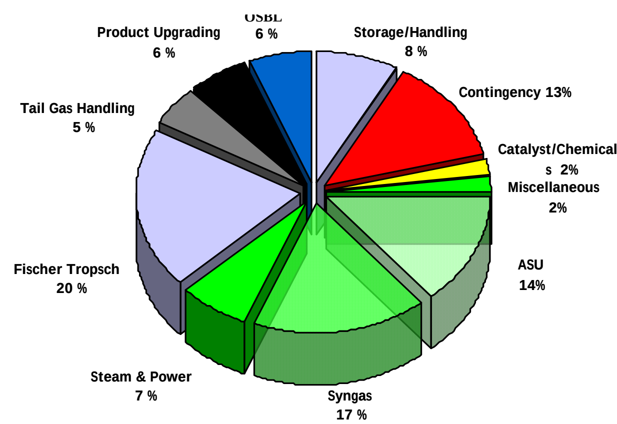
The lower level of capital costs per barrel suggests to translate into approximately U.S. $2 billion for plants with a capacity of 100,000 bbl/d. However, in reality we know that such is no longer the case. In 2003, when Qatar and Shell signed the Pearl agreement to build 140,000 barrels per day GTL plant, total costs were estimated at U.S. $5 billion (U.S. $35,714/installed bbl). Costs for this project have since escalated to an estimated U.S. $12 billion–$18 billion. In addition to two 70,000 bbl/d GTL modules this includes two offshore platforms, two sub-sea pipelines, condensate recovery and processing facilities. Similarly, the Sasol/QPC ORYX project ended up costing over U.S. $1 billion for 34,000 bbl/d (U.S. $34.343/daily barrel in 2007 dollars). (*With additional work being done at the ORYX facility to resolve startup issues this number may well exceed U.S. $1.25 billion*). These costs escalations are blamed on complex engineering works and industry-wide cost pressures including soaring steel and labor prices. The hope that the cost of producing GTL fuel will decline as a result of larger plant size is not guaranteed. We have already discussed that economies of scale from the new generation of plants are small and hardly reduce costs. We have seen that the costs reduce with size by an exponent of about 0.88, but when you are talking billions this can amount to a sizable savings.

It may be informative to note that oil refineries of around 100,000 bbl/d used to have capital costs in the range of U.S. $12,000 to U.S. $16,000 per daily barrel. In today's (2008) perspective, this range has been elevated to over U.S. $22,000 per daily barrel (the 350,000 bbl/d OilMoz refinery in the Maputo province of Mozambique was announced to cost U.S. $8 billion[11]). Research and development is focused on further reducing costs, hopefully found in better catalysts and plant design. Some still have hope that economies of scale from the new generation of plants under construction will also further reduce costs. In our view, such would require major breakthroughs, one of them possibly being modular, pre-fab construction.

The main elements of the plant we need to consider and are described in this short overview of the processes are: Feed gas conditioning/Syngas manufacture/Oxygen plants/Syngas conditioning/Syngas compression / F-T reactor section / distillation & hydro-cracking / isomerization / product storage & handling/Utilities – Out-Side Battery Limit (OSBL).

50,000 bbl/d Shell Plant @ U.S. $1.25 billion	50,000 bbl/d Conoco Plant @ U.S. $1.5 billion





Source: SRI- Shell[12]

Source: Conoco[13]

Let us have a closer look at the relative contribution of those costs to the total. For this purpose, we will use the cost-breakdown published by SRI Consulting [12] for a Shell plant configuration of 50,000 bbl/d at an estimated cost of U.S. $1.25 billion. Another excellent analysis of the costs of their F-T plant, scaled up to 50,000 bbl/d, at an estimated total cost of U.S. $1.5 billion, has been made by Conoco.[13] Above, we give the cost breakdown for both, showing the relative differences in handling the breakdown:

The cost breakdown of a GTL facility from the above sources is represented below in table-form. The table presents the individual elements and the aggregate elements In-Side Battery Limit (ISBL), being Syngas section, Fischer-Tropsch section and Upgrading section. It also shows the "normalized" ISBL items, whereby the contingencies, catalyst costs and miscellaneous have been distributed over the aggregate elements, mentioned before. It should reflect, within the accuracy of the breakdown, the difference and improvements in costs between the Shell Pox and the Conoco CPOx as well as the difference between the multi-tubular and the slurry F-T reactor technology. The cost benefit of the CPOx is evident, but surprisingly the slurry technology, in those particular cost breakdowns does not seem to be more cost effective than the conventional multi-tubular one.

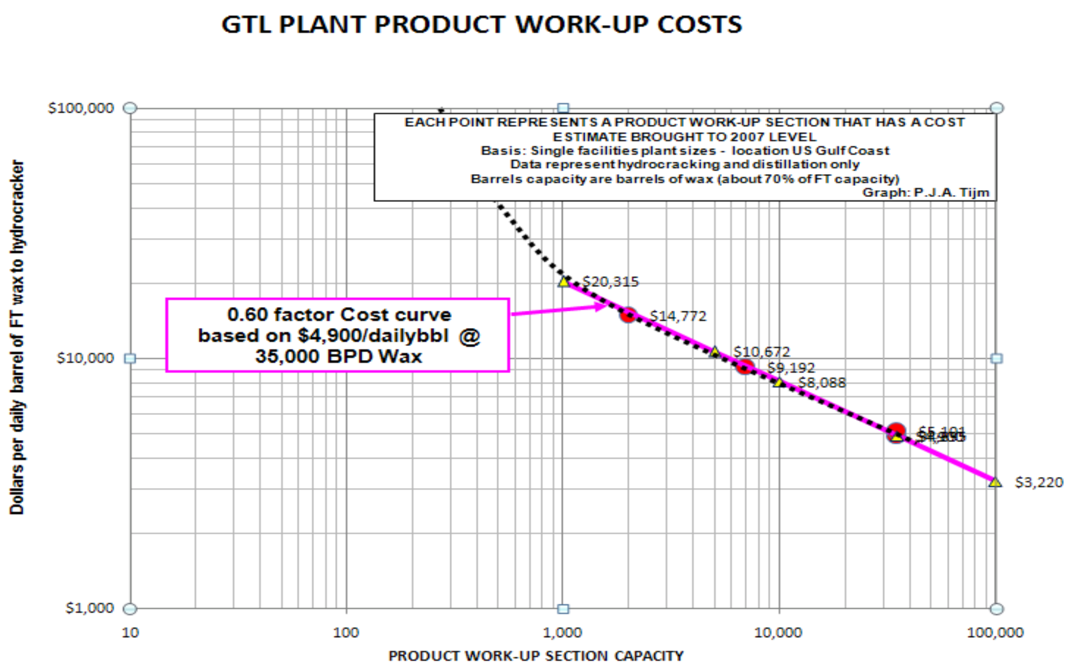
		Shell 50,000 bbl/d [12]	Aggregate elements ISBL/OSBL*	Normalized ISBL*	Conoco 50,000 bbl/d [13]	Aggregate elements ISBL/OSBL*	Normalized ISBL*
ISBL*	ASU	16			14		
	Gas Pretreatment	3			3		
	Syngas	34	57	64	24	45	54
	Steam & Power	4 + 4			4+3		
	Fischer Tropsch	15	24	26	22	30	35
	Tail Gas Handling	5			5		
	Product Handling	9	9	10	9	9	11
OSBL	OSBL	5	10		7	16	
	Product Storage	5			9		

* ISBL = In-Side Battery Limit OSBL = Out-Side Battery Limit

The "normalized" message is consistent with earlier data, showing that making syngas is expensive, which is the reason for many R&D institutes and Universities to devote attention to this. Conoco has intended to show that their CPOx addresses this to some extent and in the above numbers has clearly managed to do so. In our view, the estimate by SRI for the Shell plant is somewhat skewed towards the syngas costs. Such is partially influenced by the fact that the Shell plants need a hydrogen manufacturing unit (the Shell POx produces a syngas with a H_2/CO ratio of 1.8, i.e. lower than the user ratio). The general expression of the "normalized" costs In-Side Battery Limit (ISBL) for a Shell plant has always been 60%/25%/15% of the costs for the syngas/F-T reactor/product workup sections, respectively. However, it has been noted before and will be clear from the narrative section below, that various parts of the F-T complex have things in common: suffice to mention here the steam system, which the syngas and the F-T reactor section have in common. Or, one could point to the hydrogen system, which all three parts are linked to. So, in the repartition of the cost over the sections of the plant, some subjectivity may play a role.

Irrespective of details on the cost repartition, however, it remains a fact that a facility generating syngas is the most expensive part of the GTL plant. As a result there are currently numerous R&D projects attempting to achieve cost reduction in this area. One of those, the Ionic Transfer Membrane (ITM), executed by a DOE sponsored consortium, led by Air Products and Chemical Inc. is well enough advanced to be a serious candidate for implementation in a potential North Slope project. Such should bring the syngas costs down by an estimated 25% or overall cost down by some 15%.

We have now identified and broken down the F-T plant in its basic elements and have developed a general understanding of the costs of the individual elements. We also have a feel for the overall costs of a GTL facility, using the curve of page 7 above. From this we have concluded that for medium to large GTL plants the economy of scale is relatively small. Particularly, the syngas and F-T reactor facilities are becoming multiple units. The product work-up section, however, still lends itself to the "economy of scale": distillation columns and hydro-crackers are built as very large single units. To give an impression of the relative costs of the product work-up section, available data, including the material of SRI and Conoco presented above, have been used. It is reminded here that part of the F-T reactor effluent product stream is already in the LPG to diesel range. Therefore, as throughput parameter the effective hydro-cracker throughput, i.e. some 70% of the F-T reactor output of the plant, was taken. The cost curve obtained is the following:



Although no detailed cost data are available for the product work-up sections of the larger GTL plants in Qatar, it is our the understanding that Shell's 70,000 bbl/d Pearl facility plant still operates with one single hydro-cracker per train. Such implies that the economy of scale rule is well applicable to a capacity of 50,000 bbl/d of F-T wax fed to the cracker reactor system.

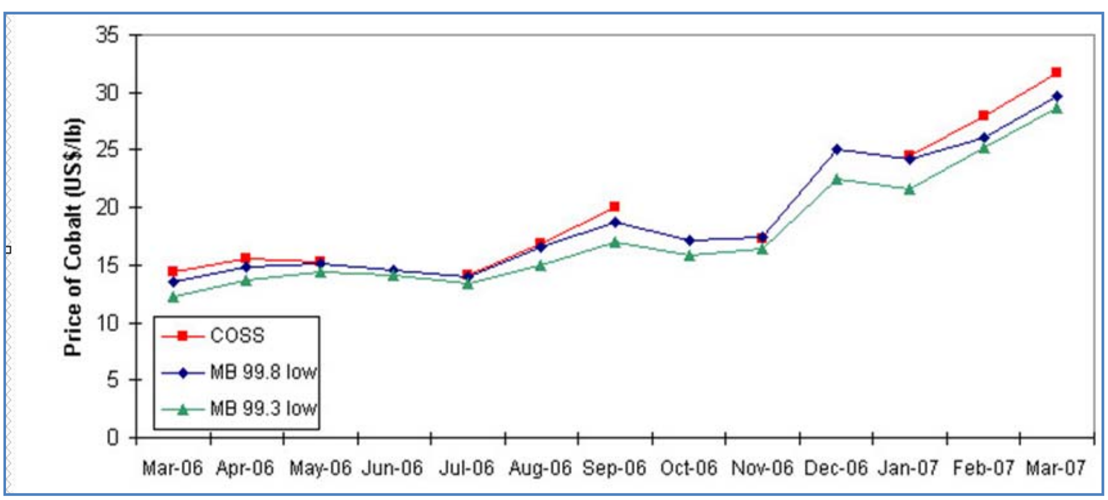
9.5.3 Catalyst Costs

Catalysts costs are a significant element in the F-T technology costs (and, hence, in the potential reduction thereof). It is also a peculiar cost element as in general the first fill of catalyst to a plant is considered part of the capital cost, while later fills are normally taken as operating costs.

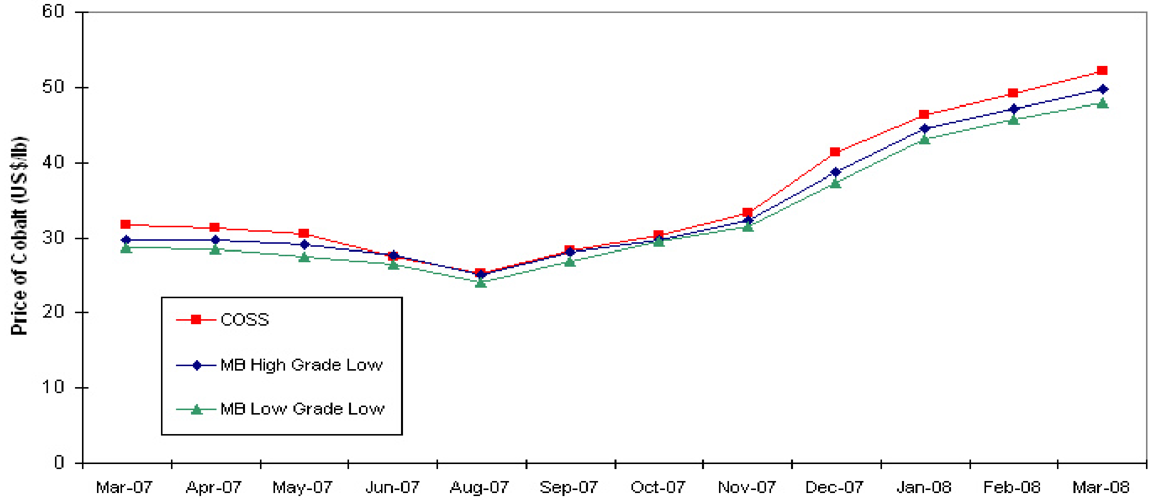
The catalyst costs are determined by the cost of the carrier, of the active metal(s) and of the preparation. As all catalysts are based on proprietary technology developments and covered by patents, it is expected that when a catalyst is made available, the commercial price will include an exclusivity element. The catalyst carrier needs to be guaranteed of high purity as trace elements of undesirable components can influence conversion and catalyst life enormously. Its price will reflect this and, hence, complicate any cost reference. A bottom floor, however, can be given, considering that alumina carriers are widely used in the hydro-cracking, hydro-treating and hydro-desulphurization processes in refineries. Depending on volume discounts, the authors have seen prices as low as U.S. $15.00 per pound of alumina carrier (2005 price level), the slurry powder carrier being obviously cheaper than extrudates, which require more manufacturing effort.

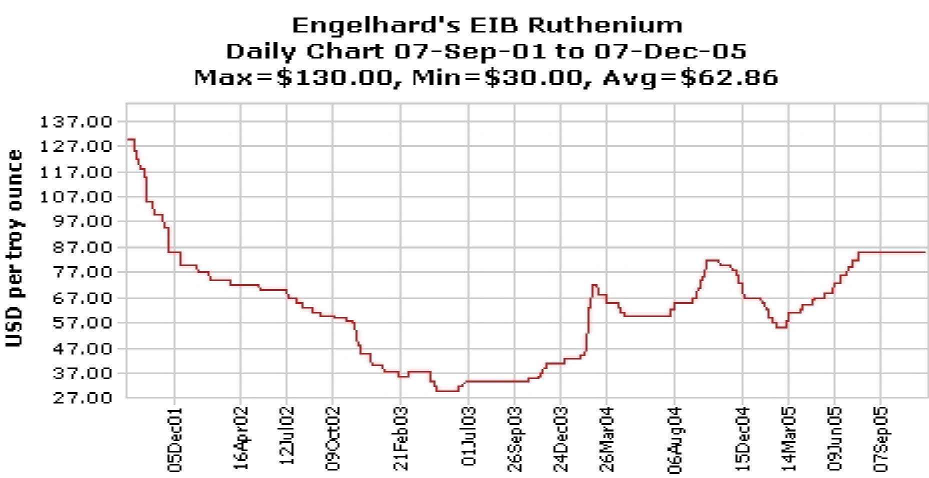
There are four metals generally accepted as active metals for the F-T reactions: iron, nickel, cobalt and ruthenium. Nickel has been found not to be commercially attractive as it makes high quantities of methane.

Metal prices of catalysts are basically fluctuating on the open market. Although catalyst manufacturers keep a close eye on the metal prices market, few of them are actually directly involved in metals trading. Johnson Matthey is possibly one exception. Hence, depending on the loading of the basic cobalt and/or ruthenium a fair, unambiguous calculation can be made of the influence of the metal on the catalyst price.



Having followed the cobalt pricing for some time, we quote BHPBilliton's opinion from their website: "Cobalt prices will probably average around U.S. $25/lb in 2004 and may remain above U.S. $20/lb for most of 2005." Actually and most recently, with the demand for material also the cobalt pricing has seen quite an increase as can be shown in the most recent update [14]:





With the above metal price indications, it will suffice to say that the ruthenium catalyst are prohibitively expensive. Costs for catalysts with 15%–20 % ruthenium would mount to U.S. $200–300 per pound, not including promoters or other special charges. However, ruthenium is the most used promoter for F-T catalysts, so depending on the loading as promoter its price contribution can still be relevant.

Although metal loading on a catalyst and the metal price are important contributors to the catalyst costs, they are unfortunately only part of the equation. One needs a carrier and also one cannot apply the active metal to the carrier in the metallic form. It needs to be applied as a metal salt, often in a nitrate form, which can be relatively easily decomposed/reduced. Hence, additional costs are involved with this process of converting the metal to salt and also losses are incurred. Including the exclusivity element, prices quoted for the typical cobalt catalyst, with cobalt loading of some 15%–20% weight, could be as high as U.S. $30.00–U.S. $60.00 per pound, carrier and metal loading depending, while iron catalysts may sell for up to U.S. $6.00 per pound.

Although the catalysts are substantially unchanged at the end of the catalytic event, secondary effects decrease the activity and selectivity over time. We mention here effects like metal crystallite size growth, metal oxidation, carbon deposition and catalyst attrition, the latter especially for slurry bed operation. Hence the catalysts need replacement. The positive aspect of the use of higher value metal is that it is worthwhile and technically possible to (largely) recover the metals in so-called reclaiming processes. Metal recovery as high as 90% wt is not impossible, however, metal recovery comes at a cost. In terms of catalyst replacement intervals we have indications from Sasol as being 2–4 years for the SPD process[15], from Shell as being 4–6 years for the fixed bed multi-tubular Bintulu operation[16] and from Rentech as being 0.5–1.0 lb. catalyst/bbl of product[17]. The latter unit is very elegant in understanding the relative cost of the catalyst. In order to arrive at similar units for the cobalt catalyst we will assume it to have a productivity of 0.1–0.125 gram C_5^+ hydrocarbons/gram of catalyst/hr. We use the aforementioned catalyst replacement numbers and take into account differences in regenerations and replacement cycles (continuous slurry versus batch fixed bed). With this we calculate the slurry reactor to produce 6 bbl/lb–16 bbl/lb catalyst in its useful life, versus 12–20 for the fixed bed reactor. Thus the catalyst replacement costs are:

Catalyst replacement costs per life cycle							
Catalyst		Iron	Iron	Cobalt slurry	Cobalt slurry	Cobalt fixed bed	Cobalt fixed bed
Replacement cycle	Years	weeks	weeks	2 years	4 years	4 years	6 years
Productivity	gr.HC/gr cat/hr			0.1	0.125	0.1	0.125
Productivity	bbl/lb/life	1.0	2.0	6	16	12	20
Catalyst cost	U.S.$/lb	4	6	30	40	30	60
Metal recovery	U.S.$/lb	n/a	n/a	8	8	8	8
Catalyst cost	**U.S.$/bbl**	**4**	**3**	**3.7**	**2**	**1.8**	**2.6**

In conclusion, the costs of catalyst per barrel of product is for all practical purposes equal for iron or cobalt and for slurry or fixed bed processes. For an evaluation of facility on Alaska's North Slope we have opted to assume U.S. $3.00/bbl for catalyst costs.

Relative catalyst costs can thus be reduced by:

1) Increasing the hydrocarbon productivity per pound;
2) Using less expensive carriers; and by
3) Reducing precious metal or cobalt content. The latter cost reduction can, on top of the lower metal loading used, also be the result of less laborious, single versus double impregnation. Exxon and Shell have both been working on this concept, although each company approached it from a different angle. Exxon's work led to the conclusion that a cobalt catalyst with gradient cobalt loading (most on the outside of the catalyst particle, little in the center) has higher hydrocarbon productivity. Exxon claims this in its patent for its "eggshell catalyst." Shell developed a "gradient" cobalt catalyst, purely with the objective to have a less costly catalyst.

Catalyst metal availability:

Finally, under this section of cost of the catalyst a few remarks on the availability of the active catalytic metals. Iron basically has an unlimited availability. Such is not the case for cobalt and ruthenium.

Cobalt data reported by the U.S. Geological Survey (U.S.GS) [18] indicate that world mine production of cobalt has been nearly 60,000 tons in 2006. The USA was, with about 20% of this, the single largest importer. The United States did not mine or refine cobalt in 2006. Main import sources for the USA (2002-05) of cobalt contained in metal, oxide, and salts are: Norway, 21%; Russia, 17%; Finland, 14%; Canada, 9%; and other, 39%. In recent years, exports of cobalt-rich ores from Congo (Kinshasa) to refineries mainly in China have helped to balance world cobalt supply and demand. Future export of these ores could be affected by declining ore grades, higher copper prices (which could influence miners and smelters to shift to copper production), the availability and increasing cost of transportation, efforts by the Government of Congo (Kinshasa) to require that cobalt ores be processed before being exported, and increased involvement of international mining companies in Congo.

As for consumption, nearly one-half of the cobalt consumed in the United States was for use in super-alloys, which are used mainly in aircraft gas turbine engines; 9% was for use in cemented carbides for cutting and wear-resistant applications; 18%, for various other metallic applications; and 24%, for a variety of chemical applications. The total estimated value of cobalt consumed in 2006 was $350 million.

Ruthenium data are reported by the U.S. Geological Survey [18] under the platinum-metals group (PGM), a group dominated by platinum and palladium (most in use for catalytic convertors in car exhaust gas systems). The platinum-group metals comprise six closely related metals: platinum, palladium, rhodium, ruthenium, iridium, and osmium, which commonly occur together in nature and are among the scarcest of the metallic elements. Along with gold and silver, they are known as precious or “noble” metals. They occur as native alloys in placer deposits or, more commonly, in lode deposits associated with nickel and copper. Nearly all of the world's supply of these metals is extracted from lode deposits in four countries—South Africa (66%), Russia (23%), the United States (5%), and Canada (4%). The Republic of South Africa is the only country that produces all six PGM in substantial quantities. In 2006, the USA imported 30,000 kilograms of ruthenium. It is important to put this number in perspective:

For example, if we assume that the Sasol ORYX catalyst would contain 1% Ru as promoter and the catalyst had been made in the USA in 2006, I would estimate that it would have consumed 1/3 of the U.S. import of that year;

Another example, if we assume that the Shell Pearl project catalyst would contain 1% Ru as promoter and the catalyst has been made in the USA in 2006, we would estimate that it would have consumed twice the U.S. import of that year. Hence, even though used as promoter in miniscule amounts, one project can seriously impact or even ruin the market and market price.

Ruthenium dioxide is used as coatings on dimensionally stable titanium anodes used in the production of chlorine and caustic.0.1% Ru is added to titanium to improve its corrosion resistivity a hundredfold. Ruthenium is also used in advanced high temperature super-alloys, applied in the blades of aircraft gas turbine engines. In its Mineral Resources Program Five-Year Plan, 2006-2010[19] the U.S. Geological Survey writes: “Rare metals such as ruthenium and indium were not in demand until recently, but now it is clear that the demand is likely to grow, and **Mineral Resources Program** must prepare to provide process understandings about how deposits of these and related commodities are formed as well as assessments of potential for undiscovered deposits both within the U.S. and around the world." Hence, we would expect upwards pressure on the ruthenium price.

9.5.4 Operating Costs

Operating costs for the GTL facility include labor, maintenance, insurance and administration as well as variable costs of consumables like chemicals, electricity, water, etc. The elements give rise to the following comments:

The **labor costs** are very size and location specific. In terms of size, the labor costs retain an economy of scale effect. In remote locations, it will reflect the requirement for highly skilled, operators. The labor number is thus to be treated very cautiously. Practical experience, however, leads us to estimate that a rough number of U.S. $4–$6 per barrel of hydrocarbons produced is not unrealistic, lacking better numbers, for the countries contemplating GTL plants to date. For our option of a GTL plant on Alaska's North Slope, we consider that additional incentives need to be given to the labor force to compensate for the extreme conditions. In our analysis for this report we will therefore use U.S. $10.00 per barrel.

Maintenance costs per year can be generalized as 0.25% of capital invested. This is an "industry average" number, which is adequate for our purposes. For our particular application this translates to about U.S. $0.65/bbl. We have, taking into consideration the extreme conditions on Alaska's North Slope, opted to assume U.S. $1.00/bbl for the current evaluation.

Utility costs need some attention: A GTL facility in a remote location is generally a self-supporting entity with respect to power, where electricity is generated with waste gases from the F-T process and other processing units. Hence, exceptions disregarded, the power cost element can be considered to be already included in the capital costs and the feed gas element. A similar reasoning can be held for water. All larger facilities are predominantly using their own desalination/water treatment facilities.

Chemical costs will obviously depend on the plant configuration. From practical experience elsewhere, a rough number of U.S. $0.50/bbl may be used. Such costs of consumables includes chemicals for water treatment, solvent for gas cleaning, catalyst sulfiding, etc. Here again, taking into account the extreme conditions on Alaska's North Slope, we have opted to assume U.S. $1.00/bbl for the current evaluation.

9.5.5 Project Costs

Without going into much detail, we want to point out a number of cost elements, which are typically connected to any project. Again, these can be very project or location specific and are often, for that same reason, excluded from any comparison data. Their magnitude, though, can be substantial.

Cost of financing – borrowing, legal and supervision costs. This is a typical example of costs that are often forgotten. We all know that the bank is, in many cases, eager to lend money. However, the bank is a profit organization and need to keep their operating cost covered. Also, banks do not generally take all the risk. They syndicate the loan. Hence, the leading bank will generally charge an upfront ***loan-structuring fee***, as well as an ***agent fee***. One of the syndicate members will execute and, therefore, be the depositary agent, charging a ***maintenance fee*** to the borrower. Additionally, the legal framework for lending, covered by ***legal fees***, needs to be put in place. This generally involves two agencies, one representing the lender, one the borrower. Finally, the progress of the project against the expenses needs to be followed. This implies that the bank will, at the expense of the borrower, generally appoint an independent engineer, a company skilled in project supervisions and monitoring, charging a ***supervision fee***. Thus, closing costs of bank loans might, depending on the loan-size, go up to 2%–4% of capital.

Cost of site preparation. Site preparation costs can be easily highlighted by analyzing the ORYX (Qatar) and Escravos (Nigeria) projects—both are 34,000 b/d, both are Sasol F-T technology—yet Escravos is budgeted at a 70% premium. In their comments, SasolChevron make the understatement that the Escravos site location is not as conducive to development as at Ras Laffan in Qatar. In reality, the Escravos site needed 3 million m^3 of sand to be deposited in the mangrove swamps to allow any construction activity. EGTL is herewith also an exception. In the cost normalization that we presented above, for the purpose of analysis all plants were located to a common location, being Qatar. Here, site preparations have been fairly minimal. Therefore, we will leave the cost of site preparation to be individually determined in an analysis.

Cost of the construction camp. Since we are, in most cases, discussing the conversion of remote, "stranded" gas, living quarters for the many, sometime up to 30,000, construction workers can be substantial. Construction camp housing could be 0.25% of capital, we believe.

Costs of infrastructure. Projects established in undeveloped regions face, in general, a location cost increase. This is the result of required infrastructure development costs associated with the operation of the facility (e.g. onshore pipelines, roads) as well as costs of distribution of the product to the market (export facilities, harbors, etc). The authors, however, have seen many examples where the local community at the development site was convinced that such also needed to include a local hospital, cinema, etc. We will also leave the cost of infrastructure to be individually determined.

Costs of project model (CADCAM). In the past, project planning for construction, accessibility of equipment, valves, etc. would be checked with the help of a "miniature," model version of the plant. Your author is still one of those who worked with miniature modelss, simulations for operators to check with. Models are now museum pieces and 3-dimensional computer models are now used instead. It was always felt that spending 0.25% of capital on a model was worthwhile and beneficial to the project, so a similar number for 3-D CADCAM modeling or the like should be reserved.

Royalty, insurance, miscellaneous costs. Whereas some of the above costs are often incorporated in the capital expenditure of a project, royalty is generally paid per barrel produced. Also insurance is an annual cost. We have for the present evaluation opted to combine these costs and charge an additional $3.00/bbl as operating costs.

Cost of product transportation. Transportation is highly dependent on the location of the plant, the market for the F-T fuel and the prevailing transportation method. In the case of a North Slope option we would assume that a pipeline and tanker tariff of U.S. $7/bbl is a good estimate for the transportation cost element to get the product to market.

9.6 LOOKING AT A GTL PLANT ON THE NORTH SLOPE

Let us work with the above data to do the analysis to show at what oil price a representative, say 450,000 bbl/d, Alaska North Slope GTL project would be competitive. Based on assumed 25% equity financing, the results show what the price of market crude would have to be for the project to pay off its costs and receive a competitive rate of return. The analysis assumes a no premium for GTL fuels over conventional WTI crude (even though GTL product is already "refined" and is cleaner than normal refined products—see below). The project is depreciated on a 20-year, straight-line basis, and is assumed to be operated at 97% utilization. Operating costs are assumed at U.S.$18/bbl (per barrel respectively: labor U.S. $10/maintenance U.S. $1/chemical U.S. $1/catalyst U.S. $3/royalty, insurance, misc.), and a transportation cost of U.S. $7/bbl is added (transportation is highly dependent on the location of the market for the F-T fuel and the prevailing shipping market; U.S. $7/bbl is on the high end of the potential cost range, but let's take it as the high end of pipeline transfer tariff costs with delivery into the California market). With a middle of the road GTL technology, requiring 8.5 million btu of natural gas to make one barrel of F-T (see Section 3) and with a unit cost of around U.S. $90,000 per daily barrel, we estimate for a 450,000 bbl/d GTL project, based upon a 25% equity investment with an 20% IRR, a 20 year bank loan at 7.5% and wholesale diesel prices in the $3.20/gallon range that the net back to North Slope gas suppliers at the GTL plant inlet will be in the $9.10/MMBtu range. At an April 2008 Henry Hub market price close of $10.60/mcf the breakeven price is around U.S. $75 per barrel without any credits and $55 per barrel, should F-T credits apply.

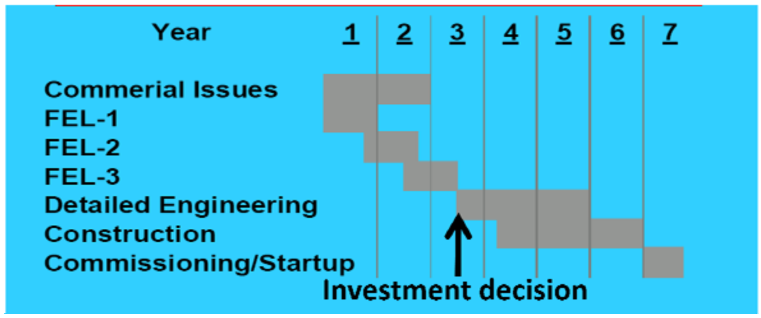
How realistic the unit cost target may be in today's environment represents a clear challenge. With more than half of the cost number being capital related, probably the biggest threat to GTL development is capital cost pressure. Capital costs were dropping until the last two years, when a run-up in demand for materials, labor and engineering/ procurement/ construction sent costs soaring. Some of this inflation is due to developments in China and India where industrialization demands large quantities of materials; some if it is also due to the boom in LNG development—GTL and LNG call on many of the same contractors and material providers. ORYX' GTL capital investment became $35,000 per daily barrel (due to start-up problems, etc), but the next generation of projects will be well above this threshold. The run-up in costs is evidenced by comparing the ORYX and Escravos projects—both are U.S. $34,000 per daily barrel, both are Sasol F-T technology—yet Escravos was budgeted at a 70% higher costs, and now, due to delays, recently announced to be already 150% higher in costs, or $53,000 per daily barrel and the end is still not in sight (part of the original 70% higher costs is, to be fair, a reflection of the fact that the Escravos site location is not as conducive to development as Ras Laffan in Qatar). The costs run-up not only means more capital is needed, but that many of these projects will be delayed.

For the current evaluation we have assumed a marker of U.S. $90,000/bbl/d, and this is not out of the question given inflation and the cost escalation companies like Shell have seen in their projects, oil would have to sustain prices well over U.S. $55/bbl long term for GTL projects to be "somewhat in the black" (depending on gas price and credits). To put this in perspective we note that, being at a level of over U.S. $100/bbl recently the IEA said oil prices will stay "very high," for the foreseeable future.[20]

9.6.1. Project Schedule, Execution and Completion

An important element in the total project cost is the project schedule, as it covers the period in which expenses are made, without having any product revenue.

A typical project schedule for a world-scale module may look like the following [21].

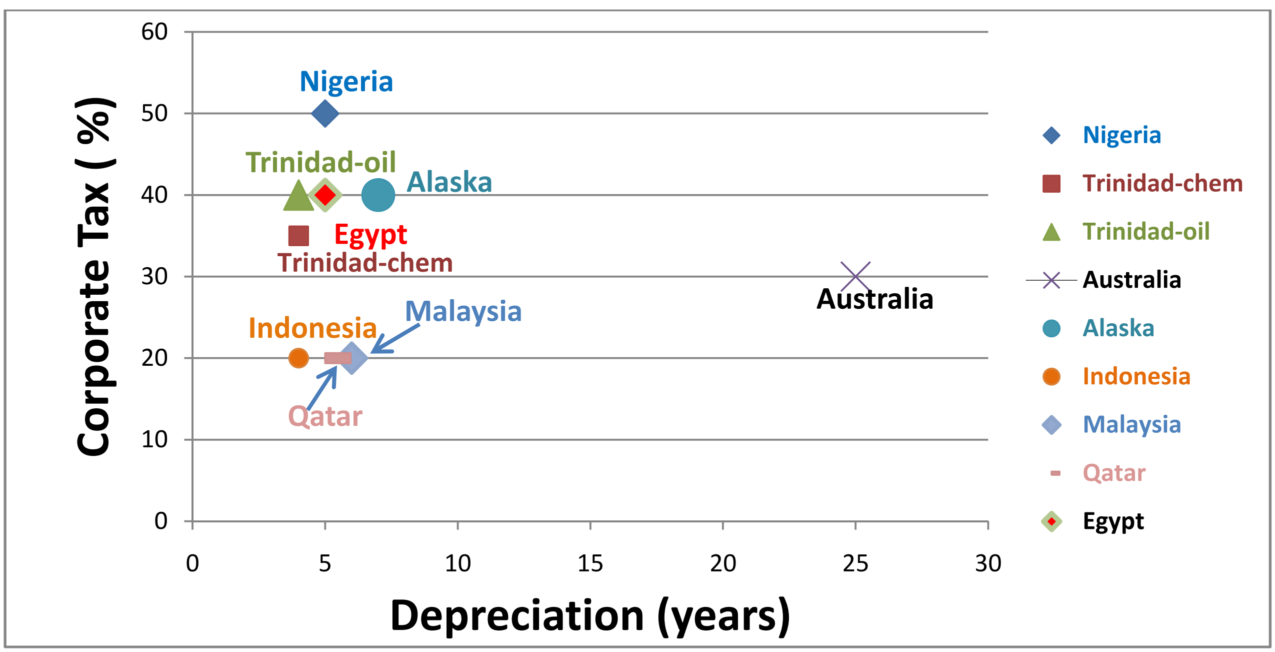


(FEL = Front End Loading studies)

The above depicts that completion of construction and start-up of the larger GTL projects typically takes a 4–5 year period, following an investment decision based on Front End Loading (FEL) studies, sometimes also called Front End Engineering Design (FEED).

9.6.2 Capital Write-off and Tax Holidays

The above underlines the capital intensity of a GTL project, which can have long payback periods. Therefore, project viability and profitability can be very sensitive to timing and the nature of taxation. The ability to depreciate the capital costs over a shorter period for income tax purposes



fundamentally influences the project economics and earnings. In certain countries and depending on what is negotiated, capital investments also are subsidized by the provision of tax holidays, import tax exemptions, etc. Corporate tax rates may also be influenced by the classification of the facility being oil or chemicals related. For F-T facilities, one can make a case for either one of the two: in essence, the product is chemically synthesized; however, it fits perfectly well in an oil infrastructure.

9.6.3 Costs of CO_2 Sequestration

If we understand methane and carbon dioxide (CO_2) to be the principal greenhouse gases and potentially one of the main culprits involved in global warming, the GTL process can both be considered as GHG consumer as well as producer. In this discussion, the GTL distillates are often compared to crude oil derived diesel when a "Well to Wheel" analysis is done. It is not a foregone conclusion that in this full fuel cycle the GTL distillates have a higher GHG emission than petroleum derived diesel. Of importance in this analysis is whether the natural gas feedstock is derived from recoverable natural gas sources or whether flared gas is utilized. Equally important is whether a comparison is made using a diesel powered or a gasoline powered vehicle, as well as whether carbon emissions are in fact released or sequestered.

Injection of CO_2 produced by the GTL process into oil or gas formations or in aquifers is a long accepted practice in enhanced oil recovery (EOR). If the CO_2 were injected in an oil or gas reserve formation, it can have value in enhancing the natural resource recovery. Injection in aquifers does not have such a "recovery" element. However, sequestration and compression of the CO_2 will be generally required before underground injection would be possible.

The additional costs for sequestration are often under discussion. They are calculated as the cost of capture, transport and geological storage of CO_2. It is not the intention of this report to present a detailed analysis of these costs; however, for the reader, understanding of the magnitude of costs can be illustrative. Your authors found a comprehensive overview of the costs, given in the following table:

Cost of Carbon Sequestration per Barrel of F-T Product[22]	
	Sequestration Costs
	(U.S. $ per barrel –basis 2003 data)
CO_2 capture and compression	2.10
CO_2 transport	0.63
CO_2 storage	0.42
Total Cost with no EOR Value	**3.15**
CO_2 value with Enhanced Recovery*	-2.94
Total Cost of Sequestration	**0.21**

One can argue about the absolute value of numbers in the above table, e.g. transport is a function of distance, etc. However, to put the above numbers in perspective, we can correlate the above to cost of energy; for example, crude oil prices, which were around U.S. $25.00 per barrel in 2002/2003. Therefore, it suffices to mention that the costs of CO_2 sequestration in 2003 were not immaterial. However, as the table shows that under a 2002/2003 oil price scenario, these costs were, at the time, almost recovered by the additional revenues from oil through EOR. *Your authors feel confident that, as long as CO_2 can be used on the North Slope to recover additional crude oil, especially at prices in excess of $60/bbl, the costs of carbon sequestration will be fully covered or in the expected case sequestering will be a profit center.

9.6.4 Potential Product Premium

In the previous discussion of the required crude oil price required for GTL projects to breakeven, we noted: *"The analysis assumes a no premium for GTL fuels over conventional WTI crude (even though GTL product is already 'refined' and is cleaner than normal refined products—see below)."* Such is an attempt to be prudent in the analysis. Already in 1994, in the Shell days of one of the authors, this was written [23]**:** *"The uniqueness of the Shell Middle Distillate Synthesis (SMDS)) products, though, including their added value, gives the SMDS process excellent opportunities to provide return on investment.*

If natural gas is priced at U.S. $0.5/MMBtu, the feedstock cost element in the product is about U.S. $5/bbl. The total fixed and other variable operating costs are estimated at a further U.S. $5/bbl. The total required selling price for the product will depend on numerous factors, including fiscal regimes, local incentives, debt/equity ratio, type of loans and corporate return requirements. The premium that may be realized for the high quality products is also a locally influenced and important aspect; it may be as high as $6–$8 U.S. per barrel over and above the normal straight run middle distillate value.

Another important factor is whether the products are for inland use or for export. For countries with sufficient gas, but who need to import oil or oil products to meet their local demand, SMDS products manufactured in that country should realize at least import parity values. In some cases, these may be far above the normal world spot market values. For such countries, therefore, the national benefit of the SMDS process may be substantial."

Product premiums have been paid for GTL diesel in markets like California, Thailand and parts of Europe. However, from the refiner's point of view we must be prudent. Refiners are inventive and are constantly improving processing and blending features to compete and survive in a very competitive market. From that point of view, let us consider product premium to be "icing on the cake" very welcome (possibly temporary) additional revenue, but not a cornerstone on which to build a GTL project.

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10 BENEFITS OF GTL FOR NORTH SLOPE OPERATIONS

10.1 Summary/Conclusions

The benefit of a GTL facility on Alaska's North Slope is not only limited to the greater revenues which will be attributable to the State of Alaska by realization of the sales of predominantly diesel fuel over the sales of natural gas. There are important secondary benefits arising from the plant. Among those are:

1) The ability to convert not only methane, but any carbon bearing molecule, like ethane, propane, butane and partially, CO_2 into synthetic transportation fuels. This gives the North Slope GTL plant operator a tool to maximize his revenue, depending on market conditions.
2) The ability to convert the plants and adjacent facilities into an energy independent unity, through recovery of process heat and off-gases.
3) The use of some fraction of the hydrocarbons produced in the North Slope GTL facility as biodegradable, synthetic drilling fluids, with the potential to bring the oil drilling costs down.
4) The ability to use the Fischer-Tropsch process effluent water beneficially for enhanced oil recovery.
5) The ability to perform the reverse water gas shift reaction, which implies actually effective conversion of CO_2 in liquid hydrocarbons as well as the ability to recover CO_2 very effectively from the syngas gas.
6) The use of CO_2 as well as the abundantly available nitrogen from the air separation plants for EOR.
7) The manpower loading until 2024 for a North Slope project of up to 900 operating people, while thereafter a steady operating manpower of between 600 to 900 operations / maintenance people seems reasonable. Such could provide for a long term stable employment, which would entail, through the economic spending multiplier, several billions of dollars per year in economic boost for the state, and is therefore an important economic development.

10.2 Introduction

In this section we will address the technical and socio-economic benefits of a GTL facility on the North Slope of Alaska. More specifically we will discuss:

- Feedstock flexibility /tool for revenue maximization
- The energy profile of the plant in relation to the North Slope
- Product from the plant, specifically synthetic drilling fluid
- The by-products of the plant – water/CO_2/nitrogen
- The socio-demographic aspect of the plant

10.3 Benefits of Feedstock Flexibility as Tool for Revenue Maximization

When discussing generation of syngas from natural gas to be used in the Fischer-Tropsch synthesis one normally considers the conversion of predominantly methane. That is because in case of conversion of "stranded" gas, other gaseous molecules, like CO_2, ethane, propane and butane are taken out as contaminants, chemical feedstock and/or liquefied petroleum gas (LPG). Such could also be the case for the Alaska North Slope gas, if not only for economical reasons, then for technical reasons. Under the latter category fall CO_2 removal, as pipeline gas specifications do not allow for higher concentrations than 3 % vol CO_2 (for corrosion reasons). For the ethane produced, there is basically no market on the North Slope, so leaving it in the gas for export would be the solution. For propane and butane extraction, either on the North Slope or elsewhere would be the option.

The benefit of the conversion of Alaska North Slope gas via GTL is that upfront removal of CO_2 from the gas is **NOT** required. On the contrary in the syngas generation process CO_2 can be usefully exploited as additional carbon source. Additionally the syngas generation process is not particularly limited to the use of methane/ethane as feedstock. Propane and butane are equally well converted into synthesis gas. Such feedstock flexibility therefore allows the North Slope GTL operator to economically evaluate the benefits of revenue generation through conversion of propane/butane into synthetic transportation fuels versus the revenue generated by sales of LPG components and maximize the revenue depending on the market situation.

10.4 Benefits of GTL Surplus Energy ("Waste Heat") for North Slope Operations

As we discussed in Section 3 (TECHNOLOGY) one of the challenges in the F-T technology is to be able to suitably manage the enormously exothermic reaction. By an exothermic reaction we mean that the reaction gives off more heat than is needed to create and sustain the F-T reaction. The most notable example of this type of waste heat reaction is a nuclear reactor – except we don't use or produce radioactive materials. As another example some may recall when we mix two compounds together to make an epoxy glue after a period of time the cement gets warm as the glue cures. The same thing happens in an F-T reaction. As the syn-gas, H_2 and CO combine in the presence of a catalyst to form a long chain molecule, the reaction gives off a lot of heat. It is critical that we remove this heat – "waste heat." What we do with the "waste heat" determines the overall efficiency of the F-T process. Dumping this waste heat into the air (cooling towers with their huge plumes of energy rising toward the sky) or into the water (cooling ponds with steam rising into the air) and it is wasted. By capturing this waste heat to produce steam to drive electric generators and heat homes or buildings, it is used to run endothermic processes (that need heat to happen) and you have save energy. We then don't need to use natural gas or fuel oil to heat water to provide electricity or heat.

This point is very important when it comes to the F-T process. While all of the natural gas contained in the inlet feed to a GTL plant is not converted into F-T fuels, most of the "energy" contained in the natural gas is utilized. When natural gas is piped to a town, some is used for heating and some is used for generation of electricity. The efficiency of the conversion depends upon the efficiency of the process. Modern home heaters are 70% to 85% efficient. The best electric generation plants, with combined cycle gas turbines are only 50% efficient. A North Slope GTL plant makes F-T transport fuels but it also provides enormous amounts of waste heat to generate electricity, heat buildings and run other processes reducing consumption of natural gas otherwise used for power generation and heating.

10.5 Benefits of GTL Surplus Energy for North Slope Operations

The F-T reaction is very exothermic – giving off a lot of "waste" heat.

$$CO + 2\,H_2 \rightarrow -CH_2- + H_2O \qquad \Delta H = -165 \text{ kJ/mol}$$

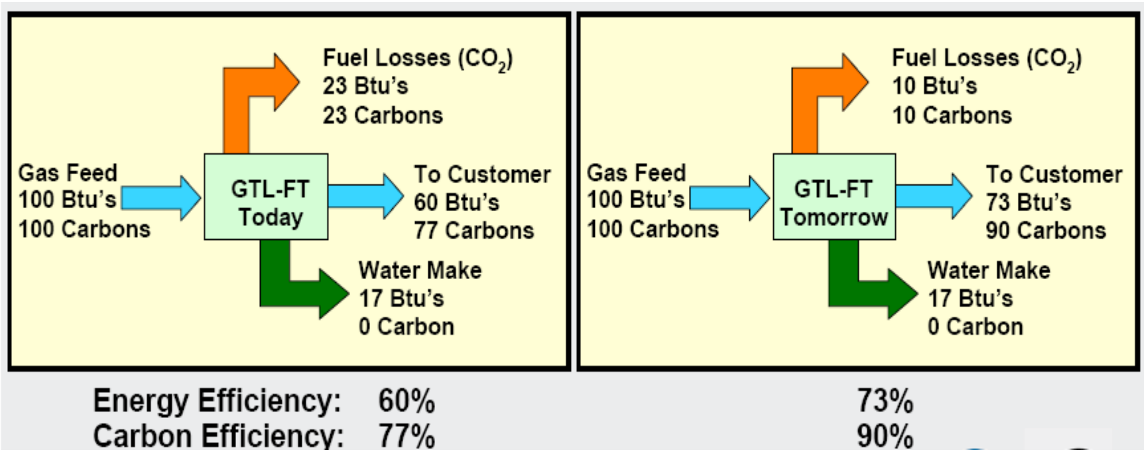
The heat of the reaction is here expressed through the enthalpy Δ H. It can, in relative terms, also be described via the thermal efficiency. The thermal efficiency is defined as the ratio of the energy in the products of the reaction over the energy of the reactants. That means that there is a relation between the product make (and carbon efficiency) and the energy efficiency. For the Fischer-Tropsch process of today, the current maximum of thermal efficiency is some 65%. Therefore, this implies that about 35% of the energy into the process is not converted to (chemical) energy of the products, but is released as heat (thermal energy) instead. Thus, almost one-third of the energy into the F-T process needs to be handled as waste heat. However, do not think that the energy as lost! Engineers have found ways and means to recover this energy to the largest extent.

Smith [1] of SRI made a presentation on potential efficiency improvement of the GTL process. He pointed to the inherent losses in the GTL process, and the coupling between energy efficiency and carbon efficiency via

water make $12CH_4 + 5.5\,O_2 \rightarrow 11\,H_2O + C_{12}H_{26}$ (diesel) and

CO2 make: $CH_4 + 2\,O_2 \rightarrow CO_2 + 2\,H_2O$

The corresponding efficiencies discussed are given in the figure below:



Source: Smith [1]

And indeed, the 77% carbon efficiency is a realistic number. Hansen [2] reported at the EFI Gas-to-Market conference in Paris 2006, on work conducted by Post Doc Carmine Luca, titled "Energy efficiency in Gas-to-Liquid processes" at the Norwegian University of Science and Technology (NTNU), Trondheim, Norway (Department of Physical Chemistry). Using F-T kinetic models and parameters from the open literature, the energy and carbon efficiency of the GTL process was modeled. Dr. Luca has taken as base case the performance of the Lurgi – PetroSA Statoil GTL system, operational in George, South Africa, i.e. an ATR/slurry F-T reactor system, being overall 23.7% loss or 76.3% carbon efficiency (equals eight MMBtu/bbl).

The diagram above depicts also the "fuel losses" and CO_2, the quantity of carbons which are not converted to useful hydrocarbon liquids and need to be rejected. In general the F-T process based on cobalt catalysis produces little CO_2, so that the unconverted syngas and gaseous conversion products can be disposed of as fuel gas for use in furnaces, boilers and/or gas turbines for electricity generation. Such a GTL facility can be designed to be self-sustaining in power and energy requirements. An example of such a case is the Shell Bintulu plant on the island of Borneo, Malaysia.

We should point out that these results illustrated above are for a temperate area. In locations like the North Slope where there is a need for large amounts of low value heat (temperatures under 200 degrees F), these thermal efficiencies will be greater.

10.6 Benefits of GTL Products, Especially Synthetic Drilling Fluids

Synthetic-based drilling fluids (SBF) are a relatively new class of drilling mud that is particularly useful in sensitive environments in combinations with deepwater and deviated hole drilling. They were developed to combine the technical advantages of oil-based drilling fluids (OBF) with the low persistence and toxicity of water-based drilling fluids (WBF). In an SBF, the continuous liquid phase is a well-characterized synthetic organic compound. A brine is usually dispersed in the synthetic phase to form an emulsion. The other ingredients of an SBF include emulsifiers, barite, clays, lignite, and lime. SBFs contain the same metals as WBFs. All are tightly complexed with the barite and clay fractions of the mud and have a low bioavailability and toxicity. Bulk SBFs are usually not discharged to the ocean. However, due to the environmentally benign character and bio degradability of SBF, drill cuttings generated during drilling with SBFs may be treated to remove SBFs and discharged to the ocean. Drill cuttings contain small amounts of liquid and solid drilling fluid components in addition to formation solids. The cuttings contain a small amount, usually 5% to 15%, adhering SBFs. The SBF base or synthetic fluid may be a hydrocarbon, ether, ester, or acetal. Synthetic hydrocarbons include normal (linear) paraffins (LPs), linear-α-olefins (LAOs), poly-α-olefins (PAOs), and internal olefins (IOs). Most drilling in the Gulf of Mexico currently is with WBFs. When WBFs are not suitable and OBFs are not selected, IO and LAO SBFs were used almost exclusively. **Since 1998, when Unocal obtained a ruling from the EPA,[3] GTL based synthetic hydrocarbons have been added to the ranks of approved synthetic drilling fluids.** Currently the main application area for SBFs is in off-shore application. However, since synthetic drilling fluid from the GTL process is fully bio-degradable, and the material would be available at lower costs than conventional drilling fluids, application for the full spectrum of drilling on Alaska's North Shelf could be attractive.

10.7 The By-Products of the Plant – Water/CO_2/Nitrogen

In section 3 (TECHNOLOGY) we discussed the beneficial use of oxygen for syngas generation in larger GTL facilities and highlighted that the process outlet for the oxygen was in the form of the main by-products of the F-T process: water. The energy diagram above also shows this clearly. This water, since it is chemically derived, is of good quality in terms of mineral loading. However, it has been in contact with the fraction of the produced liquid hydrocarbons and, hence, contains some minor traces of alcohols, acids and dissolved hydrocarbons. For a North Slope GTL project this water is the best available quality for a water flood, the next best being seawater, which needs to undergo extensive desalination/demineralization.

In areas where water is abundant (Shell GTL plant, Bintulu, Malaysia) this water is stripped from its organic components, bio-treated and reused in the own facility as far as needed, while the surplus is discharged to the adjacent river. The organic components of the water stripping process do come available, but are very small in quantity. Hence, in practice such organic components are not economically recoverable and best disposed of as component in the plant's fuel gas system.

In arid areas (Sasol, Qatar) such water is handled similarly, albeit that the surplus water is used for irrigation purposes.

For a potential application on Alaska's North Slope the quality would be excellent for secondary or enhanced oil recovery (EOR), via water flooding in addition to being a more elegant, less energy demanding, source of supply for domestic water, process water, etc. Current EOR by water flooding with sea water is hampered by the fact that this sea water is highly loaded with salts. It is not a surprise that those salts, under the conditions of the formation, where they are injected, can behave totally different than under atmospheric conditions, lose solubility characteristics and block oil passage pores rather than enhance the oil recovery. Since the water from the GTL process is chemically derived, it contains no minerals, as sea water does. It lends itself therefore eminently as use in gel-based chemically enhanced oil recovery. Gel formulations are tailored to oil bearing reservoir characteristics, but they need clean (fresh) water. Such application, utilization of the gels by one U.S. company, have resulted in the production of more than 50 million barrels of incremental oil from North American reservoirs alone.[4]

With the possible availability of clean water from a GTL plant such may well be considered on the North Slope. It is also self explanatory that desalination or distillation of sea water is a very expensive process. Initial contact with BP indicates that the company would be pleased to receive the roughly 450,000 bbl per day of non-saline water for its EOR program.

We already discussed the two possible sources of CO_2 make in the GTL process: one coming from the syngas generation via the reaction:

$$2CO + O_2 \leftrightarrow 2CO_2 \qquad \text{oxidation reaction}$$

as well as in the F-T synthesis reactor via the reaction:

$$CO + H_2O \leftrightarrow CO_2 + H_2 \qquad \text{water gas shift reaction}$$

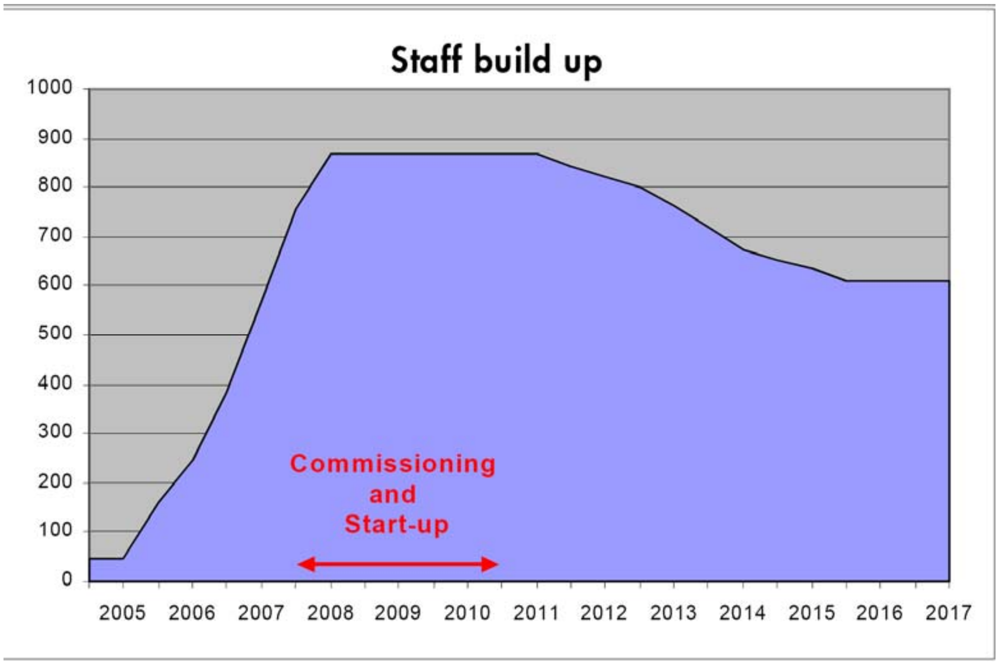
Of the two it can be said that the generation of syngas in the auto-thermal reformer of partial oxidation reactor is extremely fast, so that the formation of any CO_2 is far from the thermo-dynamical equilibrium. Also we should take into consideration that the GTL plant feed gas, through the accumulation in the light reinjection gas recycle already contains CO_2 at a 6%-10% level. This means that the water gas shift reaction will play an important role, in the sense that it will prevent the CO_2 make and actually try to revert CO_2 to CO. This is also called the reverse water gas shift reaction and will stimulate the conversion of CO_2 to CO to liquid hydrocarbons. It shall be clear that even how beneficial this reverse reaction is, it is not producing miracles. Therefore CO_2 can still be found in the reformer effluent in the lower percentage range. We will therefore suggest not to remove the CO_2 from the feed gas. Instead, since CO_2 in the syngas is a non-reactive component in the F-T catalysis and hence, only a ballast gas, it is recommended to treat the syngas prior to feeding it to the F-T reactor section. When done by amine wash or physical absorption, this would make a concentrated CO_2 stream available at medium to atmospheric pressure.

Just as water is used for EOR, so can CO_2 be used for this purpose. Alternatively injection of CO_2 into an underground reservoir trap has been investigated and practiced.

A third byproduct of the oxygen using GTL process is nitrogen. It goes without saying that, when oxygen is separated from air in a so-called air separation unit (ASU), that about four times as much nitrogen comes available from the ASU. Part of this nitrogen is to be usefully applied as blanketing or inert gas in the process facilities. Part of it may again be used for EOR in adjacent oil formations.

10.8 The Socio-Economic Aspects of the GTL Plant

Regarding the socio-demographic aspects of a GTL plant, we need to discuss the extensive and longer term man power requirements for the construction, commissioning as well as continued operation of the plant. Fabricius[5] gave a good overview of the extensive manpower requirements of the Shell Pearl 140,000 bbl/d project in Qatar. He depicted the construction of the plants to take place in two phases, each of 70,000 barrels per day. They are to be constructed "back-to-back" and completed within about 12 months of each other, with the first starting up in 2009. Manpower numbers are projected to peak at 900 staff around the time of start-up of phase two. This will gradually reduce to a level just above 600 as experience is built up and authority is delegated through a lean, flat organization as it moves from an initial functional organization to a production unit based organization. (see figure below). The figure below suggest that Shell for a phase construction, commissioning and start-up estimates a manpower requirement of close to 900 operating/maintenance people, which can be reduced to a continuous operating staff with a strength of about 600 people. We believe that U.S. North Slope workers are more efficient than those from other regions of the world so manpower requirements will tend to be on the lower side of the range.



In view of the similarity of the suggested phased construction of 5 modules there is great similarity between the Shell Pearl approach in Qatar and a possible North Slope GTL facility. The difference lays in the fact that much of the construction for the North Slope project would be modular, to be prefabricated elsewhere. In terms of productivity there may be a fair similarity between the projects as well, as both locations are climatologically disadvantaged: Qatar with the heat and drought of the desert, the North Slope with the cold and darkness. In terms of manpower skills it is predicted that a North Slope project would be most likely better staffed than the Shell Pearl project, since the Alaska North Slope GTL project would be able to draw on a trained U.S. workforce.

We would therefore expect a manpower loading till 2024 for a North Shelf project of up to 900 people, while thereafter a steady operating manpower of between 600 to 900 people seems reasonable.

In other discussions of the social-economic aspects of oil and gas facilities often the economical impact for the region is addressed. Here the so-called multiplier effect on the local economy is often brought forward as important spin-off. Multipliers of 1.5 to 2 times the spending on manpower expenses are often brought forward. Under the assumption that the assumed manpower costs of $10.00/daily barrel are realized, or $4.5 million per day, with a multiplier of 1.5 to 2 an annual boost for the local and regional economy of about $2 billion to $3 billion per annum would be obtained.

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"PIG TRAIN" - 1ST PIG CLEANING - WITH PRODUCTS - INBETWEEN OTHER PIGS

11 North Slope GTL / NGL Products Batched Down TAPS

11.1 Summary/Conclusions

One of the advantages of a North Slope GTL option is that TAPS line can remain viable for moving crude oil produced on the North Slope to Valdez for 50 to 100 or more years. GTLs will provide the minimum throughput volumes to keep the TAPS line flowing even if North Slope crude oil production drops below 300,000 bbl/d-350,000 bbl/d. Incremental GTLs and NGLs will help lower the TAPS tariff resulting in a higher netback price and a higher revenue stream to the State.

There is no question that the TAPS line can be operated as a dual/multi products pipeline. Explorer Pipeline, owned by several major oil companies has successfully operated a 1,400-mile large diameter pipeline carrying a full slate of refined products and crude oil. In fact the Explorer Pipeline model is used in many pipelines in operation today. Explorer Pipeline has offered to bring their expertise to Alaska to assist with the design and conversion of TAPS.

Once TAPS is modified to carry both crude oil and products, the currently recycled gas stream can be processed to extract NGLs for batching to Valdez. This allows for the recovery of this revenue stream within a few years, certainly long before a GTL plant could be on line or a gas line to the lower 48 could be built. Further, it is our opinion that the market for North Slope NGLs will be considerably higher at Valdez than at ACEO in central Alberta.

The interior of Alaska operates on a liquid energy economy. Batching products down TAPS will provide Interior Alaska with the opportunity to receive lower cost fuels at new delivery points along the pipeline without having to replace their existing energy infrastructure.

Modifying the TAPS line to batch crude oil and products will eliminate the need to transport liquids in the gas line. This will reduce the cost of the gas pipeline and make its operation easier.

11.2 Introduction

In 1998, when ANGTL first proposed a GTL option for Prudhoe Bay the question most asked was, "how are you going to get the products to market?" Our reply was "batching the products down TAPS in pig trains to Valdez where the different products would be segregated into tanks for loading on tankers supplying the West Coast refining centers". The immediate response was "can't be done! … you can't put crude oil and products in the same pipeline."

Experience has shown that this is not true. The experience of batching various products and crude oil was obtained with the Explorer Pipeline, a 1,400 mile 24/28 inch diameter line with 720,000 bbl/d of capacity that extends from Port Arthur, Texas to Hammond, Indiana. The Explorer Pipeline is the second largest products pipeline in the U.S. and is owned by Chevron, Citgo, ConocoPhillips, Marathon, Sun, Texaco and Shell. The Explorer Pipeline successfully batched a full slate of refined transportation fuels and crude oil during the earlier years of operation. This was done because, when the pipeline first started, there was no market large enough to fill the pipeline with products, so crude oil was shipped to provide a minimum flow volume. The same problem might be faced by TAPS in a few years if North Slope oil production continues to decline. Below is an excerpt from Explorer Pipeline's history on the issue of batching.

> The early years were tough. The factors that pointed to the need for the pipeline had changed. Lofty expectations about volumes and business didn't materialize. The Arab embargo of 1973 caused volumes to drop. In turn, the time it took to move product from the Gulf Coast to Chicago went up dramatically. The company needed to find uses for it's capacity. The decision was made to transport both crude oil and refined products.
>
> No other large-diameter pipeline had ever successfully batched and moved refined products and crude in the same pipeline. Quality control was critical, and mixing products and crude was difficult. But, using a keen blend of technology, determination and horsepower, Explorer pioneered the process. It is a method that many companies replicate to this day.

In communication between ANRTL and Mr. Tom Jensen, Vice President of Operations for Explorer Pipeline we learned that the crucial element for successful operation lays in the design of the pig train. Such is not easy, but Explorer has the expertise and the technology exists to convert TAPS into a crude oil and products pipeline. Mr. Jensen indicated that Explorer Pipeline would welcome the opportunity to assist with the design of the conversion.

In 1998, ANGTL estimated it would cost $800 million to modify the entire 800 miles to allow for continuous pigging and to add/modify the required tankage at Prudhoe Bay and Valdez. ANGTL has not updated these numbers however; in a recent meeting with BP to discuss the GTL option BP said that number would exceed $1 billion. We would not doubt such number, in view of the recent increase in materials and engineering cost of more than 40%. *Perhaps some of this capital expense would already be covered as Alyeska Pipeline Service Company now runs "smart" pigs from Prudhoe Bay to Valdez to check for mainline corrosion and also runs cleaning pigs*.

The biggest concern in batching is the contamination of the ultra clean F-T products with crude oil. The design of the GTL batching operation rests on the use of physical pigs, in a "pig train" to provide separation of products and prevent vapor pressure issues from the transport of naphtha and NGLs. A pig train is a series of pigs place in a row that perform several functions. The first pigs in the train will be used to clean the pipeline walls pushing as much oil and oil film ahead of the first products contained in the train. Following these cleaning pigs will be a large batch of butanes used to help clean the pipeline wall of any residual oil or contaminates. Following this cleaning butane batch will be another physical pig followed by another batch of butane or low value NGLs to further insure the pipeline wall is clean.

This second batch is followed by a series of pigs separating the various NGL products extracted at the gas processing plant. At the conclusion of the NGL portion of the pig train physical pigs will separate the high value F-T naphtha, middle distillate and jet-fuel. At the end of the F-T products will be another physical pig preventing crude oil from entering the pig train from the rear.

The Prudhoe Bay operation is uniquely situated to help run a crude oil products batching operation. Currently butanes are extracted from the recycled natural gas and spiked into the crude oil. This is an elegant way to sell butane as crude oil. However, too much dosing of butanes has its problems. These butanes have been the source of (higher) vapor pressure and cavitation problems on TAPS in the past. With physical pig batching, the butanes can be placed in the first part of the pig train and used to clean the pipeline walls of crude oil and contamination. These crude oil-laden butanes can then be blended with crude oil as it is loaded on tankers at Valdez, eliminating the vapor pressure and cavitation issues along the pipeline and at pumping stations.

An added advantage of batching on TAPS – All of the NGLs extracted at the Prudhoe Bay gas processing module remain in Alaska and the U.S.

Once batching is available, essentially 100% of the natural gas liquids contained in the recycle gas, estimated to be as much as 200,000 bbl/d, can be stripped out at the processing plant and batched down the pipeline to Valdez for marketing across the U.S. The question has been asked "why not send these NGL's to Canada with a gas line instead of batching to Valdez?" The answer is fraught with conflicting issues; however, one issue stands out – Market Value.

Throughout the 1980's one of the authors of this report was responsible for marketing crude oil, natural gas and products for Anadarko Petroleum's worldwide operations including Canada. Because of the requirement to process all the natural gas before it could be put into TransCanada's mainline for dew point control; there was a very large volume of NGLs placed in a limited market. This in turn resulted in a low netback for NGLs in Canada compared to the netback for the U.S. processing plants which Anadarko operated.

We doubt that this situation can be any better today and believe it will, in the near future, be potentially worse. The reason for this is that within two years the Enbridge Southern Lights Pipeline will begin transporting light hydrocarbon fuels from the Chicago area to Alberta for blending into the oil sands and heavy crudes from Alberta – the location where Alaska NGLs will be extracted from the proposed natural gas pipeline. There are several projects on the board or under construction to bring light hydrocarbons from the U.S. to Alberta for blending with the heavy crude oils. These light hydrocarbons are commonly referred to as diluents. Once these projects are completed there will be a substantially smaller market for Alaska NGL's to pursue.

We believe that if an Alaskan gas line option is chosen the best alternative would be to keep the liquids in Alaska, failing that, delivering the Alaskan gas to the Alliance Pipeline in Alberta would be a better choice as it brings the liquids to U.S. markets along with the natural gas.

What will the future TAPS tariff be with only crude oil in the line? What happens when throughput on TAPS drops below 350,000 bbl/d?

The cost to move oil through TAPS is deducted from the income the State of Alaska receives for its royalty crude and from taxes paid by the oil producers. At lower volumes, the fixed costs of the pipeline must be spread across fewer barrels, which will increase the tariff and reduce state revenues. What is more important is that there will be operating problems for TAPS at lower volumes. An addition of 300,000 bbl/day to 450,000 bbl/d of GTLs could mitigate the upward pressures on the tariff and ease operating problems by providing more fluids moving through the pipeline. Adding up to 200,000 bbl/d of NGLs to the TAPS volume would be a significant further addition.

Is there a minimum throughput required to keep the TAPS line flowing?

We are not qualified to provide an exact minimum throughput number but we are led to believe from discussions with BP, Exxon and Alyeska in 1998, when evaluating the GTL program for Prudhoe Bay that once crude oil volumes drop below 350,000 bbl/d, the TAPS line will have to be modified to move crude. Adding 300,000 bbl/d or more of GTLs plus the option to move upwards of 200,000 bbl/d of NGLs will guarantee that the TAPS line remain open to transport the last barrel of crude oil produced from the North Slope.

Should the notion of a GTL plant on the North Slope not be pursued, modification of the TAPS line to allow physical batching of North Slope NGLs should be considered if for no other reason than keeping the cost of the gas line down (no high pressure dense phase to deal with) along with keeping the tariff on TAPS down. Even if a GTL option is embraced, modification of the TAPS line to batch NGL's can begin long before the GTL plants are on line. With the ability to physically batch with pigs so that vapor pressure is not an issue, NGLs can be extracted at the gas processing plant, adding additional revenue to the State as soon as the modification is completed.

Other advantages of NGLs and GTLs batched down the TAPS line

The energy economy of the interior of Alaska operates on liquids. Fuel oil/propane for home heating, diesel/gasoline for transportation fuels and fuel oil / diesel for local electric generation.

Physical pigging will require several stations to remove/inspect pigs along the 800+ mile route. By placing off-take points and small tank farms at strategic locations along TAPS, the batched NGLs and GTLs can provide fuels for the local economy that utilizes their existing fuel infrastructure. If crude oil prices remain high and natural gas continues to be priced well below the BTU equivalent price of crude, then these NGL products may be the only way some rural communities can survive.

11.3 Regulatory Hurdles

Another frequently-raised reason which might prevent batching products in TAPS is that the existing certificate to operate does not allow for the transportation of anything other than crude oil. We can politely say that 25 years of operation shows the contrary. Since its inception TAPS has been as a minimum blending in NGLs (butane) into the crude oil stream. If the Federal Government did not allow anything but crude oil to be transported in TAPS then there would have been no blending of butanes. F-T products, NGLs extracted from the natural gas stream are no different than the butanes that have been extracted from the natural gas stream, injected into the crude oil stream and transported down TAPS for the past 25 years.

In general, other than receiving a certificate to modify the TAPS line to physically batch NGLs and F-T products (if needed) it is doubtful there will be any major regulatory hurdles for the pipeline to overcome. The transport of GTL products and NGLs is less of an environmental issue than crude oil since some GTL products are fully biodegradable and for the most part the NGLs are vaporous under atmospheric conditions. However, we suspect that the GTL plant will be the center of environmental/regulatory scrutiny, partly due to the issue of CO_2 sequestering. We have also assumed that the additional tankage required at Prudhoe Bay and Valdez to hold these new products will be joined with the application to build the GTL plant.

11.4 TAPS Modification – Potential Road Block.

It goes without saying that the overview on batching in TAPS provided here is certainly not the result of a detailed engineering study. The authors of this report contacted Explorer Pipeline and several other pipeline operating companies in the U.S. along with pipeline consulting companies. No one was willing or able to provide a definitive answer to the question of the cost to batch-pig NGLs, GTLs and crude oil across mountains; however, all indicated that with a proper engineering study, sound pipeline operating procedures, batching on TAPS would definitely work. The biggest obstacle to a successful transition would be **reluctance to change**, common in so many businesses that have been operating under one set of conditions for 20 or 30 years.

12 450,000 barrels per day of GTL capacity (4 bcf/d of natural gas) built over 14+ years

12.1 Summary/Conclusions

The state of Alaska is interested in receiving the highest value for its resource while creating the best long term opportunities for all of its citizens. Is withdrawing natural gas from the North Slope reservoirs at a high rate better or worse for the ultimate recovery of oil and the state's treasury? Certainly the U.S. energy market can use the natural gas, or GTL products; but is all out short-term development the best thing for the State or is phased long term development better?

It is not our intent to provide a definitive answer to these questions. Rather, we will outline some issues and let the State debate their relevance as they evaluate the pros and cons of a phased GTL development program or even GTL plants versus a gas pipeline to the lower 48.

Here are some points to consider:

1. Less natural gas is removed from the oil field in the early years so that reservoir engineers can evaluate the impact of selling natural gas on the ultimate recovery of crude oil.
2. A work force utilized for a longer period of time results in long term job growth and permanent residents.
3. Alaskan businesses can expand their capabilities to meet the long term needs of GTL plant construction and have the time to recover their capital investment.
4. Less capital is required up-front to build a massive GTL plant with cash flow from the first modules helping finance later modules.
5. Slow or speed the delivery of later modules as world events improve or reduce need for future expansions, with less risk to the equity owner and investors.
6. TAPS can be modified to batch immediately and 100% of the NGLs from gas processing can be delivered to Valdez before first GTL plant is on line.
7. Currently we are in a peak demand for energy and energy projects, so there is a premium to be paid to build energy projects across the world. As a result costs are doubling even tripling as $100 oil can afford these inflated costs. With time, engineering companies, construction companies and manufacturing companies will expand to meet demand and these costs will come down.
8. Next generation plants are usually more efficient and at times will have a lower capital costs as process engineers constantly improve plants with time and technology. Next generation modules, especially on the North Slope will be more efficient and/or cost less than the previous one. Thus, a long-term schedule of GTL plant construction will see greater efficiencies and cost improvements over time.

12.2 Phased Construction of a North Slope GTL Plant

We will outline several advantages of a phased North Slope GTL development program.

1. Less natural gas is removed from the oil field in the early years
   a. Less impact on crude oil recovery
2. Smaller work force utilized for a longer period of time
   a. Most of the labor force lives in Alaska
3. Alaskan businesses can expand their capabilities to meet the long term need
   a. Firms can expend the capital to expand and recover the investment
4. Less Capital required upfront to build a massive GTL plant
   a. Cash flow from the first modules can help finance later modules.
5. Slow down or increase the delivery of later modules
   a. World events can improve or reduce need for future GTL expansions
6. TAPS can be modified to batch and 100% of NGL's from gas processing can be delivered to Valdez before first GTL plant is on line
   a. Cash flow from gas processing can help finance future expansion
7. Premium being charged by engineering companies, contractors and equipment manufacturers as there not enough companies and manpower to work on all the proposed projects.
   a. With time engineering companies, construction companies and manufacturing companies will expand to meet demand.
   b. Once this occurs costs will come down. By building under a phased time table future costs could come down considerably.
   c. Possible longer term contract with equipment suppliers, resulting in lower equipment/capital costs and providing longer term work stability in the market.
8. Next generation plants are usually more efficient and at times will have a lower capital costs as process engineers constantly improve plants with time.

The basis of a phased construction program - modules

In Section 3 (Technology) we discussed design of a modern GTL plant. Depending upon the technology used a modern GTL plant will be based upon units or modules usually dependent upon the generic size of the hydrocracking plant used in the third step. As an example, if Chevron's hydrocracking technology is utilized, the typical refining module is 40,000 bbl/d. Shell Oil generally utilizes an 80,000 bbl/d plant. The gas reformer, the first step in the GTL process is available in different capacities, but the largest currently available is sized at 140 million cubic feet of natural gas per day, roughly equivalent to 17,500 bbl/d of F-T products. Current generation Sasol or Shell F-T reactors, the second step in the GTL process can produce between 13,500 bbl/d and 17,500 bbl/d again depending upon which GTL technology is used. Thus one can see the modern GTL plant unit is going to be based upon multiple reformers and F-T reactors to fit the maximum capacity of one single refining section, the third step. Larger capacity plants are going to be based upon multiples of this maximum unit size. A 450,000 bbl/d plant will be based upon multiple units. If the current Sasol/Chevron GTL technology/maximum module size was selected we would have 12 refining modules, 26 F-T reactors and 26 gas reformers. If the current Shell process/maximum module size is chosen we would have 6 refining sections/modules, 36 F-T reactors and 30 gas reformers.

As another example, let us look at an arbitrary number of 280,000 bbl/d plant: if the Sasol/Chevron GTL technology is selected we would have 7 refining modules, 16 F-T reactors and 16 gas reformers. If Shell technology was chosen for the 280,000 bbl/d example we would have 4 refining sections/modules, 24 F-T reactors and 20 gas reformers. A GTL plant would utilize more or less of these same refining, F-T and reforming modules depending upon the ultimate capacity chosen.

Thus one can see that we are building multiples of the same configuration which lends itself to building X modules per year for 10 to 15 years to achieve the same result as building all the required modules at one time with a significantly larger labor force. If the GTL developer wanted all the modules built at one time, companies all over the world would be involved in the project. If a GTL developer wanted X modules delivered each year over a 15 year period, places like Alaska with limited capability to build these modules could make the capital investment because the costs could be recovered over a longer period of time, making Alaska more competitive with existing manufacturing/fabrication centers in the U.S. Anchorage, Nikiski and Fairbanks could fabricate many of the modules throughout the year and transport them via a summer sealift or truck year around on the Dalton Highway. Other coastal towns that enjoy a moderate winter could also develop the business skill sets to build modules, offering local residents skilled jobs that can participate in resource development throughout Alaska, and eventually the Pacific Rim.

12.3 Natural Gas used to Maintain Reservoir Pressure – More Oil Production

Without question the recycling of the gas from the North Slope oil reservoirs over the last 25 years has resulted in billions of barrels of additional oil being produced at Prudhoe Bay. In 1998, when ANGTL was proposing a GTL option for the North Slope one of the biggest issues was “what impact would taking gas from the oil reservoir have on the ultimate recovery of crude oil?” The Alaska Oil and Gas Conservation Commission is charged with making this decision, and setting an allowable gas off take rate that will minimize crude oil loss at Prudhoe Bay or liquid condensate loss at Point Thomson field. ANGTL is certainly not qualified to answer that question, neither in 1998 nor today; however we were advised in 1998, that selling natural gas will result in a lower ultimate recovery of crude oil. How much less oil would be produced is a matter of engineers’ estimates and we will not have a definitive answer until gas is actually withdrawn for sale. One advantage of the phased construction is that removing 800 million to 900 million cubic feet per day per module in a phased development will give reservoir engineers a better understanding of how future gas withdrawals will affect crude oil recovery.

The consequences of oil loss are substantial. If withdrawing 4 bcf/d of recycle gas (otherwise used to help produce oil) results in 1 billion barrels of crude oil not being recovered, the cost is enormous. The value of 1 billion barrels of crude oil at today’s $120/bbl oil price is worth over 15 trillion cubic feet of gas at $8/mcf at the wellhead which could be as much as $12/mcf in the market place. Fifteen trillion cubic feet represents almost half of the current proven gas reserves. The bottom line is that, until the reservoir engineers clearly understand the impact of selling of large volumes of recycle gas, smaller may be better. A point to remember with GTLs is that alternative ways for secondary oil recovery become available. We believe the waste CO_2 and fresh water effluent streams from the manufacture of F-T products can be used to increase oil recovery at a higher rate than the loss of recycle gas will reduce recovery.

12.4 Smaller Work Force Utilized over a Longer Period of Time – Better for Alaskans

There is no question that a major construction job such as the proposed gas pipeline or a GTL plant will bring thousands of jobs to Alaska. A gas pipeline is estimated to need as many as (10,000) people in Alaska at peak construction. However, if the gas pipeline option is selected to monetize the North Slope gas, half of the total jobs will be in Canada and at the end of the three or four-year construction period almost all the jobs will disappear. This sounds like a short term win for some. When considering that Alaska does not have a large skilled work force, many if not the majority of the jobs will be filled by people from outside Alaska who will become short term residents at best. It would mean that Alaska will have to provide the resources to support this temporary work force, but what happens to the capital investment for these resources when the temporary workforce goes home?

A GTL plant, especially a 450,000 bbl/d program, will require several thousand skilled workers over a longer time but will also place a strain on the ability of Alaska to supply this labor force. Building this same size GTL facility over a 14 to 16 year period will allow communities to adjust over a longer period of time.

12.5 Businesses Can Expand to Meet Demand Given a Long-Term Opportunity

It is very difficult for a business to invest millions of dollars in sophisticated manufacturing equipment, larger indoor fabrication facilities, large cranes, expanded port facilities and training its work force for a 2 or 3 year pipeline opportunity. By providing a long term fabrication construction schedule, Alaska businesses can gear up to add manufacturing capabilities and jobs. By the time the last modules are placed in service, the first modules will be undergoing upgrading and major maintenance overhauls; providing ongoing job opportunities and business opportunities.

The goal of any major resource development should be to maximize the value of the resource, create as many long term jobs as possible and create an atmosphere for local business development. Alaska has an enormous natural resource base that will take a concerted effort to develop. Providing the construction jobs to develop these resources is one thing; providing the manufacturing capability for the refining/processing facilities is long term, year round work that builds communities and sustains them for future generations.

12.6 Less Capital Investment Required

It is hard to believe, in this day of $120 crude oil and record profits in the tens of billions range, that the oil companies don't have unlimited resources in invest in any number of projects. If North Slope gas development was the only project in the world it would not be an issue – but it isn't. While energy companies seek elephant fields, most reserve additions come from smaller, more expensive to develop reservoirs scattered around the world. Oil companies are driven to replace their current production with new gas/oil reserves so they invest in hundreds of projects worldwide. The Alaska gas line or a GTL plant represent huge investments in time, money and manpower. Whether you build a 450,000 bbl/d GTL plant in one build or phased, the plant will consist of four to six modules, each module based upon the maximum capacity of the refining section (see Section 3 Technology). This therefore allows for phasing of construction/commissioning of these modules. By building modules over a longer period of time less capital is required at one time and it becomes a training ground for employees. Cash flow from earlier modules coming on line could provide the equity capital to build subsequent modules.

12.7 Slow or Increase the Delivery Rate of Later Modules

We all like to believe that we can predict the future; history has shown that most of us fail miserably. Ten years ago most did not predict $120/bbl crude oil price in 2007. Events around the world can increase the need for new energy or delay their entry. We all believe that the economies of China and India are unstoppable and that therefore the demand for oil and gas will continue to rise at current rates. If one truly believes this, then crude oil will reach $150/bbl before too long. We know from history that at some point people will say no. An economic switch is flipped in their mind and conservation begins. One only has to look at what happened in California. When the Governor told the people (the consumers) in California that electric rates were going to double, people began conserving that very instant. The rolling blackouts, the electric energy crisis ended that day. It has taken almost four years to get back to crisis level consumption but only because the price never went as high as predicted.

A $30 billion to $40 billion investment is betting on the long term. Once a 4 bcf/d gas line or a 450,000 bbl/d GTL plant is built, one has to live with the consequences. If the market dips in response to the increase in supply or a previously unknown supply hits the market, the money is invested and one must live with the potentially lower return for the investment. If the oil or gas field responds negatively to the high withdrawal rates and the $40 billion investment is in place, the only option is to cut back on gas flow to the GTL plant or the Lower 48 – lowering the rate of return. For a gas pipeline the whole investment has to be made at once. For a GTL facility one has the opportunity to expand incrementally, thus, having a tool to lower the risk for a specific project.

12.8 TAPS can be Modified to Batch Before First GTL Plant is On-line

Batching packets of different liquids can start as soon as the TAPS line is modified. Available NGLs, in addition to the butanes, which are already extracted but injected in the crude, can be delivered to Valdez and marketed to the world. Early batching operations will give the Alyeska Pipeline operators experience before the larger GTL volumes becomes available resulting in a more efficient transition to a multi product pipeline. Batching of these products from the processing of the recycle gas will add to the state’s revenue stream and attract potential users of these products for value added manufacturing facilities at Valdez.

12.9 Premium Charged by Engineers, Contractors and Equipment Manufacturers

Currently we are in a peak demand for energy and energy projects, so there is a premium to be paid to build larger energy projects across the world. There are not enough engineering companies to design these projects, not enough engineers to work at these companies, not enough contractors to erect these facilities nor enough manufacturing companies to build the tanks, valves, compressors, motors and thousands of others items required to complete these new projects. As a result costs are doubling or even tripling as a $120/bbl oil price can afford these inflated costs. We know that in response to the U.S. Congress providing accelerated depreciation for expansions to existing U.S. refineries, almost every refinery in the U.S. is undergoing some sort of work activity. To qualify, these expansions must be in service by 2011. These projects have put a strain on the work force normally involved in design, manufacture and construction of a refinery. GTL or CTL facilities are nothing more than sophisticated crude oil refineries or chemical plants. We believe some of the increase in estimated capital costs are a direct result of this Congressional program. Projects bid today will reflect this demand. Projects bid in 2010 or later may not. Of course expansions in China and India along with the Canadian tar sands projects will impact the costs of building on the North Slope.

A good example of the cost escalation is the development in Qatar. We will here compare the Sasol ORYX GTL plant and the Shell Pearl GTL project in Qatar. The Sasol ORYX GTL project has a capacity of 34,000 bbl/d and cost $1.2 billion dollars for an installed cost of roughly $35,000 per installed barrel. This Sasol GTL plant came online in early 2007. The estimated cost to build the 140,000 bbl/d Shell Pearl GTL facility, to come on-stream after 2009, is over $60,000 per installed barrel based solely on the increased demands for the services of engineers, contractors and equipment suppliers. As a result many GTL projects, and many energy projects in general, are being put on hold until costs come down.

There is general belief that such cost escalation cannot go on, that from the demand side the energy-related boom will flatten out and eventually costs will come down again. From the supply side, gradually, more engineers will graduate from schools, more engineers will gain the necessary experience, contractors will have caught up with building projects, and manufacturers will have expanded to meet demand. Then, as history has shown, the cost of developing new projects will come down. Will this take 2 years, 4 years or more? Only time will tell, but it is there that an Alaska North Slope phased-built GTL facility will have an advantage.

The possibility of staggering the start of each module of a GTL facility offers the opportunity for the costs to drop dramatically. A phased development program satisfies the State’s need to develop additional natural resources while spreading the time to fully develop the resource over a longer period of time.

12.10 Next Generation Plants are Usually More Efficient

One only has to look at the first Sasol CTL plants built in Sasolburg and Secunda South Africa and the process upgrades and updates installed over the years to realize that tomorrow’s technology is more efficient, sometimes less capital intensive than yesterday’s. Another good example of this is the Shell Bintulu GTL plant. When the plant first came online in 1992, it produced 12,000 bbl/d of products using 100 million cubic feet per day of natural gas. *(This ratio referred to in Section 3.3 and 9.4.1, shows that it takes 8.3 mcf of natural gas to make one* *barrel of F-T product).* When the GTL plant was shut down in 1997, to repair the oxygen plant, Shell engineers updated the process with the result that when the GTL plant restarted in 2000, it was capable of producing 15,000 bbl/d of products. That was a 25% increase in (almost) the same installation.

A GTL plant on the North Slope will be unique in the GTL world. All the operating GTL plants today are situated in temperate to warm climates where waste heat removal is an issue. A GTL plant on the North Slope will be able to operate more efficiently because of the cold climate and engineers will be able to tweak or modify components as they gain operating experience. The likely result of this is that the second or third module will be slightly more efficient than the previous as will the fourth and fifth. As more and more CTL and GTL plants are built around the world catalyst companies will develop better, more efficient, catalysts, vessel/reactor designs will be improved so that company X can beat out company Y in sales. One only has to look at crude oil refinery designs. Today there are half as many operating refineries in the U.S as 25 years ago but the remaining refineries produce more products than twice as many originally did. In a free competitive world we see the trend continuing in building a better mouse trap for less money.

ANRTL

GTL vs LNG

VALUE ($) VS EFFICIENCY

IS THE LNG PROCESS MORE EFFICIENT - WITH 80 % OF THE WELL HEAD ENERGY REACHING THE MARKET ?
IS THE GTL PROCESS LESS EFFICIENT - WITH 65 % OF THE WELL HEAD ENERGY REACHING THE MARKET ?

TECHNICALLY, LNG IS A MORE EFFICIENT PROCESS IF YOU JUST LOOK AT DELIVERED ENERGY TO THE MARKET
IT IS HOWEVER TOTALLY FALSE IF YOU LOOK AT THE VALUE ($) OF THE DELIVERED ENERGY IN THE MARKET

LNG BEGINS LIFE AS NATURAL GAS AND ENDS LIFE AS NATURAL GAS

GTL BEGINS LIFE AS NATURAL GAS AND ENDS LIFE AS A REFINED PRODUCT SUCH AS DIESEL

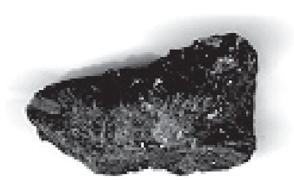
WHILE BOTH ARE CARBON BASED, THEIR VALUES ($) ARE TOTALLY DIFFERENT

AS AN EXAMPLE:
A LUMP OF COAL AND A DIAMOND ARE BOTH CARBON BASED. UNDER TREMENDOUS PRESSURE AND HEAT (A MANUFACTURING PROCESS), A LUMP OF COAL CAN BECOME A DIAMOND. WHICH HAS MORE VALUE, A LUMP OF COAL OR A DIAMOND? DOES IT MATTER THAT A DIAMOND IS A FRACTION OF THE SIZE OR WEIGHT OF THE ORIGINAL LUMP OF COAL?

IF GTL PRODUCED DIESEL IS MORE VALUABLE THAN LNG DERIVED NATURAL GAS SHOULD YOU CARE IF THE GTL PROCESS IS LESS EFFICIENT IN CONVERTING ENERGY SO LONG AS THE VALUE RECEIVED FOR THE ORIGINAL ENERGY IS GREATER.

WHICH WOULD YOU PREFER ?

A LUMP OF COAL



OR A DIAMOND

LNG PRODUCED NATURAL GAS

OR GTL PRODUCED DIESEL

THE CHOICE SHOULD BE SIMPLE
GO FOR THE HIGHER NETBACK VALUE ($)

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RICHARD J PETERSON

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AREAS OF QUALIFICATION

Mr. Peterson has spent the last 30 years in the energy business as a CTL/BTL/GTL project developer, an engineer/marketer, including 4 years as a consultant and has worked on projects as diverse as a coal gasification plant using Sasol/Lurgi technology in North Dakota; establishing a market presence in the US and Canada for new gas ventures; developing power generation projects in the US and Central America; and developing GTL, electric power plants, iron ore reduction plants and pipeline distribution systems for commercial gas markets in South Africa.

Mr. Peterson is currently the President of Alaska Natural Gas to Liquids Company in Anchorage, Alaska; a company he formed late 1996 to pursue gas to liquids (GTL), and President of Alaska Natural Resources To Liquids a LLC formed in 2005, to pursue coal to liquids (CTL) and bio-mass to liquids (BTL) opportunities to produce Fischer-Tropsch diesel (FTD) in Alaska. ANGTL/ANRTL evaluate specific project locations, financing options and fuel supply, and then evaluate the best available technology for that specific location. The North Slope GTL project that ANGTL proposed 6 years ago using Sasol GTL technology still remains one of the best options to develop the stranded North Slope gas reserves.

ANRTL is in the early engineering phases for three separate CTL and BTL projects in Alaska using Sasol's, Shell's and CHOREN's gasification technology to produce the syn gas for the F-T diesel process. The first project will use bio-mass, dead or dying spruce trees as a feed stock while the second will be a bio-mass/coal gasification/combined cycle electric generation facility located on the western shores of the Cook Inlet. The third project will site a 500 bbl/d BTL plant on the Yukon River.

EMPLOYMENT HISTORY

- President Alaska Natural Gas To Liquids Company, Anchorage, AK, 1997 to present
- Senior Consultant, Hagler Bailly Consulting, Inc., Houston, TX, 1997
- Consultant/Vice President of Business Development, McAlister Enterprises, New Braunfels, TX, 1995-1997
- Manager of Supply, Southern California Gas Company, Los Angeles, CA, 1993-1995
- Proprietor, Peterson & Associates, Woodlands, TX, 1991-1993
- Vice President of Marketing, North Canadian Marketing, Ltd., Houston, TX, Orange, CA, Calgary, Alberta, 1991
- Vice President of Marketing, Enserch Gas Company, Houston and Dallas, TX, 1989-1991
- Manager of Marketing, Anadarko Petroleum, Houston, TX, 1981-1989
- Various Supply and Engineering Positions, Natural Gas Pipe Line Company of America, Chicago, IL and Houston, TX, 1975-1981

EDUCATION

- The University of North Dakota, MS, Mechanical Engineering, 1975
- The University of North Dakota, BS, Mechanical Engineering, 1974

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SUMMARY PROFILE

Thirty years of diversified experience in technological and commercial management. Solid leadership, strong expertise in analysis, development and commercialization of synthesis gas conversion, Liquefied Natural Gas technology and commercialization, new design concepts, refinery technology, operations, scheduling, start-up, budgeting and project management. Proven success in building and managing highly motivated professional teams. Excellent communication skills and fluent in 7 languages: Dutch, English, German, French, Swedish, Norwegian and Danish. Understanding of Spanish. Author of over 70 articles and inventor/holder of 11 patent series.

PROFESSIONAL EXPERIENCE

VICE PRESIDENT – CHIEF TECHNOLOGY OFFICER- 2002-present
PV Enterprises, Inc , Golden, CO
- Director/Consultant in energy R&D and project development of multi client program.
- Successfully started multi million dollar R&D program and pilot plant facilities.

DIRECTOR FOR PROJECT DEVELOPMENT 2000-2002
Rentech, Inc., Denver, CO
- Manage project development, research and product quality aspects for the proprietary Rentech Fischer Tropsch technology.

MANAGER MARKETING/RESEARCH SYNGAS CONVERSION SYSTEMS 1996-2000
Air Products and Chemicals, Inc. - Allentown, USA
- Manage Air Products and Chemicals' research and development syngas technology programs, in particular Liquid Phase technology.
- Commercialize Air Products and Chemicals' proprietary Liquid Phase Methanol™ Technology.
- Program manager for the Air Products/Industry/University research and development Programs sponsored by the US Department Of Energy.

MANAGER OF MARKETING AND RESEARCH 1992-1996
Shell International Petroleum Company, Ltd. - London, United Kingdom
- Manage Shell International Gas' research and development programs in LNG production and storage, pipeline gas and gas conversion within Shell's Manufacturing Service Company and five laboratories. Annual Budget of U.S. $10 Million.
- Conduct marketing, gas commercialization and power generation studies for Brunei, Malaysia, China Japan and Nigeria. Promote Shell's US$850 Million gas conversion project (SMDS).
- Advise in contractual matters in LNG sales between Brunei to Japan and Nigeria to Turkey.
- Launched cost reduction studies in all elements of the LNG production chain, in gas conversion and in pipeline gas; results implemented obtained 15% improvements.
- Maintain and evaluate Shell's patent portfolio in gas conversion technology.
- Author and presenter of papers on Shell technology in gas conversion, LNG technology and cost reduction in world-wide conferences and professional training courses.

GROUP LEADER COAL GASIFICATION 1990 - 1992

Shell Internationale Petroleum Maatschappij B.V. - The Hague, The Netherlands

- Directed a 7 person team responsible for up scaling coal gasification technology intended for application in larger size, commercially available gas turbines.
- Initiated Shell/GE/Air Liquide studies into new coal gasification/power generation concepts leading to the successful development of a 450 MWe IGCC power station proposed for Japan.
- Co-ordinated the coal gasification R&D between Shell The Hague, Deutsche Shell, Shell Oil Company and Shell's research laboratories in Amsterdam (KSLA) and Houston, Texas, USA.
- Regular presenter of Coal Gasification technology at international conferences.

PROGRAM MANAGER SHELL COAL GASIFICATION 1989-1990

Shell Oil Company - Houston, Texas, USA

- Assisted in commercialisation of Shell Coal Gasification Technology through introduction of, presentations to and communication with potential customers.
- Created, implemented and completed a R&D program at Shell's Coal Gasification Demonstration Plant which obtained all design information for the first commercial Shell Coal gasification plant now operational in The Netherlands. Span of control: ~100 people, budget US$ 25 Million/year.
- Scheduled and agreed with the plant manager the runs on experimental conditions and coal types.
- Member of the EPRI/Shell Advisory Committee for coal gasification.

SECTION HEAD GASIFICATION AND HYDROCARBON SYNTHESIS 1987-1989

Koninklijke/Shell Laboratorium (KSLA) - Amsterdam, The Netherlands

- Headed an R&D section tasked to develop the synthesis gas manufacture, coal gasification and hydrocarbon synthesis processes. Work force: ~ 40 people, annual budget of US$15 Million.
- Established design parameters for new development in the Shell Middle Distillate Synthesis (SMDS) and coal gasification processes, currently operating in Malaysia and The Netherlands, respectively.
- Completed projects successfully through strong interface with the process development and engineering sections in Shell's Oil and Chemical Manufacturing Divisions plus the Catalyst Business.
- Active in recruitement and training of PhD's for Shell.

REFINERY TECHNOLOGY MANAGER 1984 - 1987

Shell Raffinaderi Aktiebolag - Gothenburg, Sweden

- Supervised refinery technology, product quality laboratory, refinery inspection and construction services departments. Annual budget of US $60Million and a work force of 50 people.
- Successfully completed projects under tight schedules, including conversion of the refinery instrumentation system, refinery effluent treatment plants and improvements of the tank farm by installing internal floating roofs and radar level gauges. A very intriguing project was to construct a 80,000 m³ cavern, next to an existing LPG cavern, under the fully operational refinery.
- Member of the refinery management team especially charged with environmental affairs, refinery concession, permits and external relations.

- Negotiated new contracts for district heat delivery from the refinery to Gothenburg Energy Works.

SENIOR REFINERY TECHNOLOGIST – Shell, Gothenburg, Sweden 1981-1984

- Co-ordinated various projects including Total Isomerisation Process, Residue Vacuum Flasher, Steam Boiler and refinery Low Temperature Heat Recovery.
- Performed refinery efficiency studies and long term master planning for the refinery.
- Guided junior technologists, trained new technologists and recruited Swedish engineers for SIPM.

ASSISTANT PLANT SUPERVISOR/OPERATIONS TECHNOLOGIST 1978-1981
Raffinaderie de Cressier S.A. – Shell, Cressier, Switzerland

- Analysed and recommended measures to improve the refinery availability.
- Implemented various improvements successfully which eliminated problems and/or reduced back-on stream time significantly.
- Handled shift supervision for the total refinery operations, product storage, rail and road car loading as a member of the "Refinery Management Team".
- Implemented and commissioned refinery projects such as the Total Isomerisation Process, Residue Vacuum Flasher and heat-integration.

TECHNOLOGIST – Shell, Cressier, Switzerland 1977-1978

- Conducted energy efficiency improvement studies for the refinery.
- Supervised optimum operation and technological aspects of refinery acid gas treating, hydro-treating, platforming processes and refinery environmental performance.
- Advised on catalyst replacement and supervised successful regeneration of the catalysts of hydro-treater, hydrodesulphurizers and platformer.

DEVELOPMENT ENGINEER 1974-1977
Shell Internationale Petroleum Maatschappij B.V. - The Hague, Netherlands

- Advising engineer to Shell's refineries in design/operation of hydroprocesses and catalytic reforming.
- Designed and developed gas treating processes including acid gas and mercaptans removal, molecular sieve/glycol drying and chloride removal.
- Participated in design teams of the North Scotland gas project and North West Shelf LNG project.
- Commissioned and debottlednecked treating processes in Germany, Pakistan and Venezuela.

TRAINING/MILITARY SERVICE 1973-1974
Shell Internationale Petroleum Maatschappij B.V. - The Hague, Netherlands

- Served as lieutenant in the Dutch Army charged with supervision of and advise on nuclear, biological, and chemical (NBC) material handling.
- Lectured in NBC matters at the Royal Military Academy of Breda and co-ordinated NBC research.

EDUCATION

Master of Science,Chemical Engineering, Delft Technical University (1973);
Bachelor of Science, General Economy, Erasmus University, Rotterdam (1974);
Chairman of Energy Frontiers International, 1996-1998
Author of over 70 articles and inventor/ holder of 10 patent series.

PETER J.A.TIJM -- PUBLICATIONS

Tijm P.J.A., "“Gas to Liquids, Fischer-Tropsch Catalysis, Reactors, Products and Process - The Twentieth Century And Beyond" , 2005, available on website under www.booklanddirect.com

Liu ,Yafeng, Zhang, Jun Z, Tijm, Peter J and Vanderborgh, Nick., Catalytic Partial Oxidation of Natural Gas to Synthesis Gas II: Three-Dimensional Simulation, presentation at the AIChE 2003 Spring National Meeting, New Orleans, LA, March 2003.

Rogers D.V. and Tijm P.J.A.,"Upgrading and Characterization of Rentech Iron Based Fischer-Tropsch Products", presentation at the AIChE 2002 Spring National Meeting, New Orleans, LA, March 10-14, 2002.

Tijm P.J.A., "Analysing the commercial viability of GTL technology",presentation at the IBC Gas-to-Liquids Conference, London, UK, February 27-28, 2002

Tijm P.J.A., Waller F.J. and Brown D.M., "Methanol technology developments for the new millenium" contribution in Applied Catalysis A: General 5776 (2001) 1-8 , Elsevier.

Tijm P.J.A., 'Assessment of Different Feedstocks for Synthesis Gas Production and Fischer-Tropsch (F-T) Conversion', presentation given at the IBC Gas-To-Liquids, Viability, Economics and Strategy Conference, Houston, TX, October 29-31, 2001

Chapman E.M., Boehman A.L., Tijm P.J.A., and Waller F.J., 'Emission Characteristics of a Navistar 7.3L Turbodiesel Fueled with Blends of Di-Methyl Ether and Diesel Fuel' paper presented at the Fall 2001 SAE Fuels and Lubricants Meeting, San Antonio, TX, September 24-27, 2001.

Tijm P.J.A., 'The Viability of Gas-To-Liquids in The Middle East', presentation given at the 2nd Annual Middle East Oil and Gas Conference, Houston, TX, June 28-29, 2001.

Hess H.S., Szybist, J., Boehman A.L., Tijm P.J.A., and Waller F.J., 'Impact of Oxygenated Fuel on Diesel Engine Performance and Emissions" paper presented at the 35th National Heat Transfer Conference, Anaheim, CA, June 10-12, 2001.

Tijm P.J.A., 'Comparing Gas To Liquids Technologies: A Market For Everyone?', paper given at the CatCom2001 Conference, Houston, TX, May 14-15, 2001.

Peng X.D., Toseland B.A., and Tijm P.J.A., 'Development and Status of the Liquid Phase Di-Methyl Ether Process (LPDME™), paper presented at the 6th Natural Gas Conversion Symposium, Girdwood, Alaska, June 17-22, 2001.

E. C. Heydorn, P. J. A. Tijm, B. L. Bhatt, B.T. Smith and R. M. Kornosky, Liquid phase methanol (LPMEOH) process Development, Energy 2000 Proceedings-US ISBN:1587160161

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Tijm P.J.A., 'Status of the Sand Creek Fisher-Tropsch Fuels Conversion Project', paper given at the Energy Frontiers International Conference, San Francisco, CA, October 11-13, 2000

Chapman E.M., Bhide S.V., Boehman A.L., Tijm P.J.A., and Waller F.J., 'Emission Characteristics of a Navistar 7.3L Turbodiesel fueled with blends of oxygenates and diesel' paper presented at the Fall 2000 SAE Fuels and Lubricants Meeting, Baltimore, MD, October, 2000.

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Hess H.S., Boehman A.L., Tijm P.J.A., and Waller F.J., 'Experimental Studies of the Impact of CETANER™ on Diesel Combustion and Emissions' paper presented at the Fall 2000 SAE Fuels and Lubricants Meeting, Baltimore, MD, October, 2000,. SAE Technical paper series, 2000-01-2886.

Peng X.D., Toseland B.A., and Tijm P.J.A., 'Qualitative Analysis of the Syngas-To-DME Reaction System.' Paper presented at the 3rd China/USA Joint Chemical Engineering Conference, Beijing, China, Sept. 25-28, 2000.

Hess H.S., Szybist, J., Boehman A.L., Tijm P.J.A., and Waller F.J., 'The Use of CETANER™ for the Reduction of Particulate Matter Emissions in a Turbocharged Direct Injection Medium-Duty Diesel Engine' paper presented at the Seventeenth Annual International Pittsburgh Coal Conference, Pittsburgh, PA, September 11-15, 2000.

Heydorn E.C., Tijm P.J.A, Bhatt B.L., Smith B.T. and Kornosky R.M., 'Liquid Phase Methanol (LPMEOH™) Process Development' paper presented at the GlobeEx 2000 - The Global Energy Exposition, Las Vegas, NV, July 23-28, 2000.

Moore R.B. and Tijm P.J.A., 'Liquid Phase Reactor Technology", Workshop on Polygeneration Stategies Based on Oxygen-Blown Gasification, Beijing, China, May 11-12, 2000.

Frye, C. A., A. L. Boehman and P. J. A. Tijm. A Comparison of CO and NO Emissions from Propane, *n*-Butane, and Dimethyl Ether Premixed Flames. *Energy & Fuels*, **13**, 650-654 (1999).

Peng X.D., Toseland B.A., and Tijm P.J.A., 'Kinetic Understanding of the Chemical Synergy under LPDME™ Conditions - Once-Through Applications.' Chem. Eng. Sci. (1999), 54, 2787.

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Tijm P.J.A., et al 'Particulate Matter Emissions Reduction with CETANER™ as a Blend Component for Diesel Fuels with Low Cetane Levels' paper presented at the Windsor Workshop in Toronto, Canada, November, 1999.

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Bhatt B.L., Heydorn E.C., Tijm P.J.A., and Kornosky R.M., 'Direct Applications of Stabilized Methanol from the Liquid Phase Methanol (LPMEOH™) Process' presented at the 16th Annual International Pittsburgh Coal Conference in Pittburgh, PA, October 11-15, 1999.

Hess, H. S., J. A. Chiodo, A. L. Boehman, P.J.A. Tijm and F.J. Waller. The Use of CETANER™ for the Reduction of Particulate Matter Emissions in a Turbocharged Direct Injection (TDI) Diesel Engine. Sixteenth Annual International Pittsburgh Coal Conference, Pittsburgh, PA, October 11-15, 1999.

Heydorn E.C., Stein V.E., Tijm P.J.A., Street B.T., and Kornosky R.M., 'Liquid Phase Methanol (LPMEOH™) Project Operational Experience' presented at the EPRI/GTC Gasification Technologies Conference in San Francisco, CA, October 4-7, 1998.

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Heydorn E.C. and Tijm P.J.A., 'Liquid Phase Technology Developments for The New Millennium' paper presented at the EFI Gas Conversion Conference,San Francisco, CA, October 7-9, 1998.

Miller W.R., Tijm P.J.A., Toseland B.A., and Waller F.J., 'Liquid Phase Technology Developments for The New Millennium' paper presented at the Sixth Annual Technical Seminar Promotion of Clean Fossil Energy Technologies in the APEC Region, Reno, NV, October 6-9, 1998.

Brown, D.M., Tijm P.J.A., Miller, W.R., Toseland, B.A., and Waller, F.J., ' "CETANER™" a Promising New Diesel Fuel' paper presented at the 12th International Symposium on Alcohol Fuels, Beijing, P.R. China, September 21-24, 1998.

Foster E.P., Tijm P.J.A., Bennett D.L., Advanced Gas-To-Liquid Processes for Syngas and Liquid Phase Conversion' Prco. of the 5th Natural Gas Conversion Symposium in Taormina, Sicily, Italy, September 20-25, 1998, pp. 867-874.

Tijm P.J.A., Miller D., Brown D.M., Allam R.J., and Goldstone P.G., 'Oxygen Production for Floating Production, Storage and Off-Loading Mounted GTL Projects' paper presented at the EFI Gas Conversion Conference in San Francisco, CA, October 7-9, 1998.

Peng X.D., Toseland B.A., and Tijm P.J.A., 'Kinetic Understanding of Chemical Synergy in LPDME™ Process' paper presented at the 15th ISCRE in Newport Beach, CA, September 13-16, 1998.

Brown D.M., Miller D., Allam R.J., and Tijm P.J.A., 'Generation of Synthesis Gas Off-Shore: Oxygen Supply and Opportunities for Integration with GTL Technologies' Proc. of the 5th Natural Gas Conversion Symposium in Taormina, Sicily, Italy, September 21-25, 1998., pp.949-954.

Goldstone P.G., Tijm P.J.A., and Miller D., 'The Safe & Efficient Provision of Oxygen for Remote, Offshore Conversion of Natural Gas' paper presented at the Gas Processors Assiciation, European Chapter, Continental Meeting, Zurich, Switzerland, September 23-25, 1998.

Hess H.S., Roan M.A., Bhalla S., Butnark S., Zarnescu V., Boehman A.L., Tijm P.J.A., and Waller F.J., 'The Use of Oxygenated Diesel Fuels for Reduction of Particulate Emissions from a Single-Cylinder Indirect Injection Engine' paper presented at ACS National Meeting, Symposium on the Chemistry of Diesel Fuels in Boston, MA, August 23-27, 1998.

Hess, H. S., M. A. Roan, S. Bhalla, S. Butnark, V. Zarnescu, A. L. Boehman, P.J.A. Tijm, F. J. Waller. Reduction of Particulate Emissions from a Single-Cylinder IDI Engine with Oxygenated Diesel Fuels. In ACS Preprints, Division of Petroleum Chemistry, 43(4), pp. 593-596 (1998).

Boehman, A.L. and Tijm P.J.A., 'Incorporating Oxygen in Diesel Fuel as a Means of Reducing Engine Emissions' presented at the Diesel Engine Emissions Reduction Workshop, Castine, ME, July, 1998.

Tijm P.J.A., 'Overview of CETANER™ For Diesel Fuel and AET Study of CETANER™ Blended With Low Cetane Diesel Fuel' paper presented at the Windsor Workshop in Toronto, Canada on June 8-10, 1998.

PETER J.A. TIJM

Heydorn E.C., Stein V.E., Tijm P.J.A, Street B.T., and Kornosky R.M., ‘Commercial-Scale Demonstration of the Liquid Phase Methanol (LPMEOH™) Process: Initial Operating Experience’ paper presented at the 6th Clean Coal Technology Conference in Reno, Nevada on April 27 - May 1, 1998.

Miller W.R., Heydorn E.C., Moore R.B., and Tijm P.J.A., ‘Advances in Liquid Phase Technology’ paper presented at the 23rd International Technical Conference on Coal Utilization & Fuel Systems in Clearwater, Florida on March 9-13, 1998.

Heydorn, E.C. Stein V.E., Tijm P.J.A., Street B.T., and Kornosky R.M., ‘LPM Process Demo: 1997 Was An Exciting Year’ in January 1998 issue of the “In Industrial Catalysis News”.

Tijm P.J. A., Waller F.J., Heydorn E.C., Peng, X.D., Toseland B.A., Moore R.B., and Bhatt B.L., ‘Gas to Liquids Processes’ paper presented at the Monitizing Stranded Gas Reserves Conference on December 10-12, 1997 in Houston, Texas.

Tijm P.J.A., Waller F.J., Heydorn E.C., Peng X.D., and Toseland B.A., ‘A New Premium Diesel Fuel From Methanol’ paper presented at the 1997 World Methanol Conference on December 8-10, 1997 in Tampa, Florida.

Tijm P.J.A., Waller F.J., Heydorn E.C., Peng X.D., Toseland B.A., Moore R.B., and Bhatt: **B.L,**.‘Alternate Fuels from Coal Through Application of Liquid Phase Conversion Technology’, paper presented at the 5th Annual Technical Seminar of the Asian-Pacific Economic Co-operation (APEC) Experts’ Group on Clean Fossil Energy, 27-30 October, 1997, Reno, NV.

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Frye C.A., Boehman A.L., and Tijm P.J.A., ‘A Comparison of Carbon Monoxide Emissions from Butane, Propane, and Di-Methyl Ether Flames’, In Proc. 1997 Fall Mtg. Eastern States Section of the Combustion Institute; 27-29 October 1997, Hartford, CT., pp. 411-414.

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Tijm, P.J.A.,. Heydorn E.C., Brown, W.R. and Moore, R.B.,’ Advances in Liquid Phase Technology’, paper presented at the American Chemical Society Meeting, April 15, 1997; San Francisco, CA.

Tijm, P.J.A,. Heydorn E.C., Brown, W.R., and Moore, R.B. ‘Overview of the Liquid Phase Methanol (LPMEOH™) Process Demonstration at Kingsport’, paper presented at the American Institute of Chemical Engineers, Spring 1997 Meeting, Houston, Tx, 9-13 March 1997.

Lange, J.-P. and Tijm, P.J.A., 'Methane Conversion Routes: Economic Screening Through Energy Management', paper presented at the ISCRE conference, Brugge, Belgium, 1996.,published in Chem.Eng Sci, 1996, 51,2379

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PETER J.A. TIJM

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Klein Nagelvoort, R and Tijm, P.J.A., 'Cost Reductions in LNG Export Facilities', paper presented at the 14th World Petroleum Congress, Stavanger, Norway, May 29-June 1, 1994.

Tijm, P.J.A., 'The Shell Middle Distillate Process, an update', paper presented at the American Chemical Society Conference, Clinton, N.Y., USA, May, 1994.

Tijm, P.J.A. and Stanton, E., 'Natural Gas Utilisation Processes', paper presented at the GPA South America Chapter conference, Caracas, Venezuela, May, 1994.

Booth, R and Tijm, P.J.A., 'Production of Hydrogen & Methanol', paper presented at the Cambridge Energy Symposium, Cambridge, UK, May 4, 1994.

Tijm, P.J.A., Marriott, J.M., Senden, M.M.G and Van Wechem, H.M.H., 'Shell Middle Distillate Synthesis: the Process, the Products, the Plant', paper presented at the Alternate Energy '94, La Quinta, Ca, USA, April 26-29, 1994.

Tijm, P.J.A., Van Wechem, H.M.H., and Senden, M.M.G., 'The Shell Middle Distillate Project. New opportunities for marketing natural gas', Proc. Of the Alternate Energy ’93 conference, Colorado Springs, April 27-30, 1993.

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Tijm, P.J.A., 'Shell's kolenvergassings technologie', presentation to the section Heat technology of the Royal Dutch Engineering Society, Utrecht, The Netherlands, March 10, 1992.

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Inventor or co-inventor of 11 patents series in the area of coal gasification, synthesis gas manufacture and hydrocarbon synthesis.