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Review of ways to transport natural gas energy from countries which do not need the gas for domestic use

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Abstract

There are a number of options of exporting natural gas energy from oil and gas fields to market, including pipelines, liquefied natural gas (LNG), compressed natural gas (CNG), gas to solids (GtS), i.e. hydrates, gas to wire (GtW), i.e. electricity, gas to liquids (GtL), with a wide range of possible products including clean fuels, plastic precursors or methanol and gas to commodity (GtC), such as aluminium, glass, cement or iron. Any gas energy export route requires a huge investment in infrastructure, and long-term 'fail proof' contracts, covering perhaps 20 years or more. But which is the best way to monetise the gas? Gas rich countries, such as Trinidad and Qatar are currently in this challenging debate. There could be options for handling niche markets for gas reserves which are stranded (no market) and for associated gas (on- or off-shore) which cannot be flared or re-injected, or for small reservoirs which cannot otherwise be economically exploited. Transportation of natural gas as hydrate or CNG is believed feasible at costs less than for LNG and where pipelines are not possible. The competitive advantage of GtS or CNG over the other non-pipeline transport processes is that they are intrinsically simple, so should be much easier to implement at lower capital costs, provided economically attractive market opportunities can be negotiated to the gas seller. The transport options preferred by governments and companies must not only take the economic risks into account but also consider the negative effects of possible terrorist activity, political changes and trade embargos over long periods of time. In this paper, we cover many of the essential technical points and broad economic pointers needed to enter the discussion of gas rich states which do not need the gas for domestic use, but wish to monetise their reserves by export.

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1. Introduction

Natural gas is becoming a major energy commodity. Gas is used for power (electricity), heating energy and fuel for fixed engines or in motor transport (transport fuel), a chemical feedstock (plastic precursors and clean fuels) or an energy source for making a commodity which needs large energy requirements in its manufacture [1].

The real purpose of any gas producer is to monetise their gas. Monetising the gas can be selling the gas as a fuel to a buyer, or selling the energy within the gas by selling derived commodities, or selling to market the compounds that make up the gas as feedstock or as plastic precursors. But which method is most robust to ensure security of investment over the period of a project's life (perhaps over 20 years) against market fluctuations, trade embargos, terrorist activity, political changes or improved technical changes reducing unit product cost. One new development for a seller is the gas refinery [1]. Designs now exist where integrated complexes use gas in an optimised manner for making aluminium, iron, cement, glass, etc., for LNG, for conversion to other products such as polymers, methanol, ammonia, iron, etc., and where waste heat and by-products can be used in other associated processes [1–3]. Such refineries will enable lower costs, hence keeping the products competitive in the marketplace. But should gas be exported as natural gas or as a refined product (e.g. plastic) or a commodity (e.g. aluminium)? The governments of gas rich countries, e.g. Indonesia, Brunei, Qatar, Arab Emirates and Venezuela, etc., are having this challenging and important debate at the moment. The Republic of Trinidad and Tobago in the Caribbean, where current exploration and geological evidence suggests it has may be up to 100 trillion scf of gas reserves, are two small islands with an underemployed population that has a government which wants to increase its economy so is developing a gas master plan to best exploit its gas potential [4].

This paper examines some of the technical methods by which natural gas energy can be transported as a fuel, as an energy or as a commodity. It covers many of the essential points needed to enter the discussion. We mention some comparison of costs where they are important for our discussion but leave detailed economic analysis until the technologies have been tried at large scales.

2. Natural gas

Natural gas is seen as the premium fuel for electricity and heat generation, but only if the energy can be delivered to the customer cheaper per therm (excluding environmental premium costs) than the conventional fuels of diesel, fuel oil or coal. This is because burning gas produces less than half the CO_2 emissions per unit of generated electricity compared to the conventional fuels [1], which is an important factor as the emission of greenhouse gases, sulphur dioxide and dust are becoming increasingly unacceptable worldwide. Gas is also ideal for use in combined cycle power plants (gas plus steam), as the efficiency is much greater than conventional steam-cycle plants [1,2].

Gas is nowadays used in the manufacture of energy intensive commodities such as aluminium, glass, bricks, cement and iron bars. Here the gas is converted to thermal or electrical power, which is then used in the making of the commodity, and the commodity is then sold on the open market. Thus the gas energy is in essence converted to the commodity, i.e. gas to commodity, GtC, Section 8. The components in natural gas, methane, ethane, propane, *n*- and iso-butanes and pentanes are all useful in their own right, as discussed in Sections 6 and 7, for gas and gas to liquids, GtL, and for plastic precursors.

Unfortunately, natural gas is usually found in places where it cannot be used. Much gas is stranded, meaning that it has no current market, such as in the many on- or off-shore fields where there is no pipeline, or when flaring of associated gas is prohibited. These location difficulties have prevented gas from reaching market and in many countries, e.g. Trinidad and Qatar, have prevented development of gas reserves for many years until the 'dash for gas' created new markets and safe long-term contracts [1–3].

Gas is difficult to store or transport because of its physical nature and needs high pressures and/or low temperatures to increase the bulk density, whereas oil is readily stored in large, relatively simple and cheap tanks and then transported in huge tankers. Gas, as a result of the storage difficulties, needs to be transported immediately to its destination after production from a reservoir [2]. On the other hand, oil is often expensive to recover from reservoirs compared to gas, and oil is beginning to have a limited long-term life as reservoirs are being abandoned when they become uneconomic [1,2].

There are a number of methods of exporting gas energy from an isolated field for use elsewhere, Fig. 1. Methods include:

- pipelines,
- liquefied natural gas (LNG),
- gas to liquids (GtL),
- gas to commodity (GtC),
- gas to wire (GtW), i.e. generate electricity at the producing field and transport the electricity by cable,
- compressed natural gas (CNG), and
- gas to solids (GtS), i.e. hydrates.

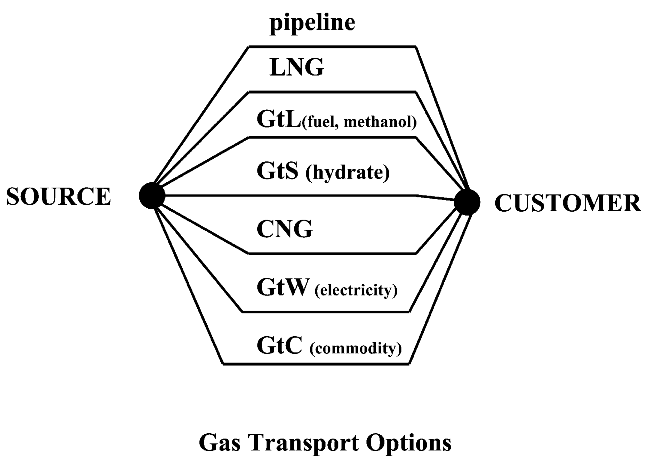

Fig. 1. Gas transport options.

The cost of transporting natural gas per unit of energy to distant markets is much higher compared to oil (perhaps 10 times [2,3]) because of its volume–pressure behaviour, and currently usually occurs by pipeline onland, or, increasingly, via liquefied natural gas (LNG) for overseas [1–3]. LNG production at present costs around US$ 15/bbl oil equivalent (i.e. $ 2.5/thousand scf of gas) but many importing countries do not have the capital to build the huge storage and regeneration facilities. Selling small volumes of LNG is not yet economically attractive to the LNG market. Likewise, intermittent gas is also not economically attractive to the major gas buyers for LNG facilities, pipelines or large scale commodity manufacturers. Thus for the smaller markets, e.g. islands where pipelines or LNG are not economical, and for smaller fields a different more flexible, cheaper, less massive, transport approach is needed for stranded gas where the quantities can be far better regulated and designed for the local needs, e.g. a power station.

Worldwide energy analysts have examined each method as a potential commercial export route and all are being developed, certainly to pilot stage [1,2]. The price of the gas can have a dominating influence on the viability of the development of a hydrocarbon reservoir, and on the success of a particular process, particularly GtL or GtC projects, because of market competitiveness.

2.1. Gas sources

Sources of gas may be non-associated gas reservoirs (i.e. only gas within the reservoir) or associated gas from oil reservoirs, which is gas produced along with oil as pressure drops [2]. Some associated gas is always produced when crude oil is produced.

Non-associated gas is directly controllable by the producer; one just turns the valves. Associated gas is dependent on the rate of oil production and the amount of gas dissolved in the oil when it is produced, thus supply can be unreliable. Non-associated gas is normally 95% or more methane; non-associated gas contains some quantity of ethane, propane, etc., which are valuable premium products in their own right, and are usually extracted for separate sale at source or primary processor.

Worldwide, governments are mandating that producers stop flaring associated gas, as their citizens perceive that it is a waste of a valuable non-renewable resource. There are often regulatory restrictions on when produced gas can be re-injected, or flared, with an understanding that any re-injected gas must eventually be produced. When such restrictions occur, oil production must be stopped until this associated gas can somehow be exported or re-injected.

The re-injection option can appear attractive at first sight, offering the added advantage of maintaining reservoir pressure, but the costs are high for the drilling and completion of the injection wells, the subsurface equipment, and the topsides equipment required to clean, pressurise, and inject the gas. The gas is basically making an expensive round trip from the production well to the topsides and back down the injection well. This is sunk cost, perhaps US$ 0.25–0.5/million scf, since no monetary value is gained from the gas until it is sold. Thus oil producers would like to have a robust cost effective way of disposing of ‘stranded’ gas, otherwise they could suffer shut down.

3. Current major methods for transporting gas energy as gas to market

3.1. Pipelines

Pipelines are a very convenient method of transport but are not flexible as the gas will leave the source and arrive at its (one) destination [3]. Once the pipeline diameter is decided the quantities of gas that can be delivered is fixed by the pressures, although an increase in the maximum quantity can be achieved by adding compressors along the line, extra pipe in the form of loops or by increasing the average pipeline pressure. However, if the pipeline has to be shut down the production and receiving facilities, be it gas reservoir, processor or refinery often also have to be shut down because gas cannot be readily stored, except perhaps by increasing the pipeline pressure by some percentage.

Pipeline pressures are normally 700–1100 psig (although 4000 psig lines are in operation) depending on the material of construction and the age of the pipe. Installation of pipeline costs currently, on average, US$ 1–5 million per mile, sometimes even higher, depending on the terrain (such as for onshore, mountains or for offshore, seabed flatness and depth) plus compressor stations, so that distance becomes a very large factor in the overall cost of the line; cost being approximately proportional to distance. Over, or at times, undercapacity has to be accommodated. Overland pipelines are vulnerable to sabotage in hostile counties, often have to cross several political boundaries, and are uneconomic for small reserves. Subsea lines over large marine distances and difficult marine environments such as deepwater (trenches), ice scouring or where fishermen are active can be difficult to maintain, and so be uneconomic. Nevertheless, novel construction methods including laser-welding techniques are at commercial status which should enable faster pipelaying. Drag-reducing agents and treatments of the inner pipe surface are being introduced to increase flow throughputs and new corrosion resistant materials are under development [1]. Naturally, safety and the environment have to be considered at all times and must not be compromised, particularly when trying to reduce costs.

Export by pipeline onland is extensive throughout Europe, USA and soon South America [1]. Subsea lines over 2000 miles have, until recently, been regarded as uneconomic, because of the subsea terrain making pipeline installation and maintenance expensive and any recompression along the route difficult, but proposals are being announced and designs being asked for tender (e.g. Middle East to Pakistan and India, and Venezuela to the United States [4,5]).

3.2. Liquefied natural gas, LNG

Liquefied natural gas is the liquid form of natural gas. Gas cooled to around −162 °C liquefies, and has a volume ~1/600 that of gas at room temperature. Export by LNG to Japan, the United States and Europe from distant production fields has now become economic due to improvements in technology and thermodynamic efficiencies of LNG facilities [1,2] but it is still expensive, often equivalent to oil costing $ 15 per bbl ($ 2.5/thousand scf of natural gas) for its journey from the reservoir to being landed at the consumers' storage tanks. However, the incremental cost of transport per mile is less than for pipeline [3].

LNG facilities require complex machinery with moving parts and special refrigerated ships for transporting the LNG to market [1–3]. The costs of building LNG plant have lowered over the past 25 years because of greatly improved thermodynamic efficiencies so that LNG is becoming a major gas export method worldwide, with 15 billion scf/day (approximately tripled since 1990) and many plants being extended, or new ones built in the world, e.g. Nigeria, Angola, Qatar, Egypt and Trinidad [1]. But such projects require long-term committed chains (Fig. 2), perhaps over 20 years, which need extensive legal contract negotiations, and any link in the chain can suddenly become fragile.

Huge cryogenic tanks are needed to store the LNG; typically these may be 70 m diameter, 45 m high and hold over 100 000 m^3 of LNG. At the consumer end, an infrastructure for handling the reprocessing of vast quantities of natural gas from LNG is required, which is also very expensive and vulnerable to sabotage. Even though the cost of producing LNG has fallen by some 40% since 1985, LNG plants are large scale, long contract (~20 years or more) and require large >3 Tscf gas reserves and ~US$ 1 billion investment for a train processing around 500 million scf/day [3]. The current largest specially built refrigerated tankers can carry 135 000 m^3 LNG, equivalent to 3.2 Bscf of gas, but are very expensive [3,5]. This makes it difficult for LNG to use smaller isolated (offshore) reserves and to serve small markets commercially because it is this large capacity, continuous running that keeps thermodynamic efficiency and costs to a minimum. Thus small volumes of intermittent gas are not economically attractive to the major gas sellers for LNG facilities. However, small well-insulated LNG container trade is being investigated, and if successful small quantities of LNG may be able to be delivered from the LNG storage, just like the gasoline tankers of today. Even so, the LNG must be stored for periods of time (months) without significant boil-off losses, which is difficult. Additionally, there must be someone prepared to develop this market.

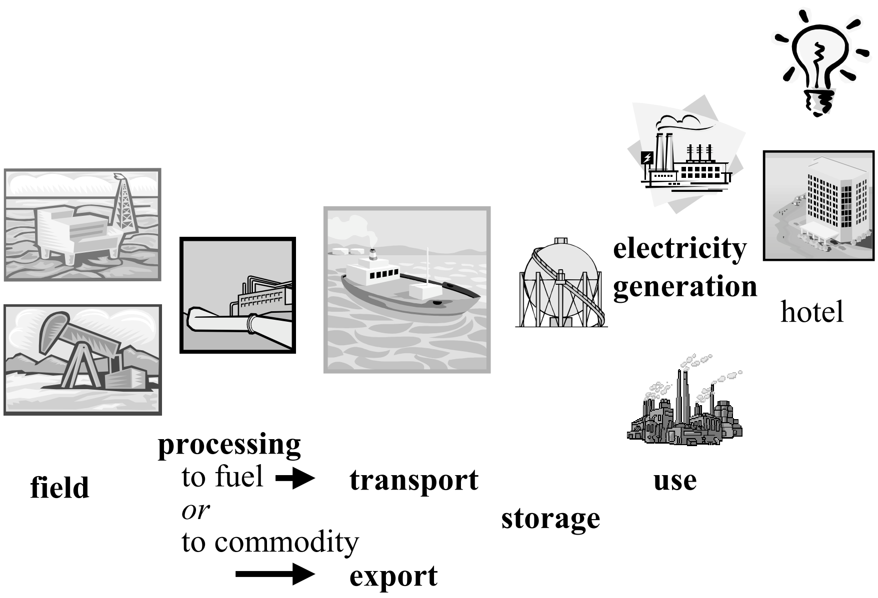

Fig. 2. The transport chain.

4. Other methods for transporting gas energy as gas

There are a number of other methods now being investigated for transporting gas for use elsewhere.

4.1. Compressed natural gas, CNG

Gas can be transported in containers at high pressures, typically 1800 psig for a rich gas (significant amounts of ethane, propane, etc.) to roughly 3600 psig for a lean gas (mainly methane). Gas at these pressures is termed 'compressed natural gas'—CNG. CNG is used in some countries for vehicular transport as an alternative to conventional fuels (gasoline or diesel). However, the time to fill a tank with 3000 psig gas can be slow and frustrating. The filling stations can be supplied by pipeline gas but the compressors needed to get the gas to 3000 psig can be large, noisy, multistage and expensive to purchase, maintain and operate. The thermodynamics of gas compression (heat generation), and gas expansion (significant cooling), have to be considered in any gas processing operation and appropriate heat exchangers used, which adds significant costs. A gas network is also needed.

Originally, the transport containers were heavy-walled (and hence heavy in weight) pressure vessels, but recently new lighter designs have been proposed. One design uses relatively long lengths of thin-walled tubing (6.25 in. outside diameter with a wall thickness of 0.25 in.) coiled into large diameter reels, termed by the inventors as a Coselle, 'a coil in a carousel' [6,7]. The carousel structure is important since it not only protects the pipe from damage, even against total break, but it permits stacking 6–8 units high. The inventors initially proposed a Coselle of length 9.6 miles which would stand some 11 ft high with a 50 ft outside diameter and 10 ft inside diameter and contain approximately 3 million scf of gas at 3000 psig. The Coselle would have many vertical girders around the outside so that it would be a large safe pressurised gas containment system. The long-term viability of the coiled tubing under repeated loading/unloading is being tested, but no serious difficulties are anticipated. The total weight of pipe and associated structures (perhaps 500 tonnes) has to be transported along with the gas, but the inventors claim that the lower fabrication costs for the gas containers makes this design attractive. They have also now designed Coselles for smaller markets [7].

An alternative approach, Votrans™ [8,9], has dedicated transport ships carrying straight long, large diameter pipes in an insulated cold storage cargo package. The gas has to be dried, compressed and chilled for storage onboard. By careful control of temperature, more gas should be transported in any ship of a given payload capacity, subject to volume limitation and amount and weight of material of the pipe (pressure and safety considerations). Suitable compressors and chillers are needed, but would be much less expensive than a LNG liquefier, and would be standard, so that costs could be further minimised. According to the proposers, the terminal facilities would also be simple and hence would be of low cost.

These CNG systems would make transport possible either for stranded gas (i.e. in places where there is no current market or no export pipeline) or for smaller quantities of associated gas which cannot be flared or re-injected. The number and size of Coselles or Votrans ships can be scaled to fit demand and would depend on daily production rates from the reservoirs (whether variable or not), and weight restrictions of transporters. Case studies by the inventors [7,9] have shown that large quantities of natural gas (~500 million scf) can be transported to markets at costs substantially below LNG costs over short distances, and probably over longer distance when the largest ships are employed. Ships capable of carrying Coselles up to 1 Bscf each and Votrans capable of carrying up to 2 Bscf have been proposed [6–9]. However, further consideration suggests that it may be a misconception to try to make the CNG ship as large as a LNG ship. LNG ships must tie up to a wharf and deliver liquid into a storage tank for re-gasification over several days. Also, a potential problem could be that ships are required to be fully safety inspected every 5 years and this is difficult for ships too heavy/large to dry dock.

An ideal CNG transport facility for this trade might be in fact a fleet of smaller ships perhaps delivering gas daily directly into the distribution pipeline, with as many ships as the distance requires, or perhaps into a system with some backup storage in case a ship is delayed in transit. Such CNG transport systems would be more flexible and cope with variable gas supplies such as associated gas. This could be an attractive challenge to the LNG transport facilities. CNG transport for the intermittent and stranded gas market could be envisioned where the produced gas is cleaned, compressed and stored, in say a Coselle, until full enough for the Coselle to be taken to market.

4.2. Gas to solid, GtS, natural gas hydrate

Gas can be transported as a solid, with the solid being gas hydrate. Natural gas hydrate (NGH) is the product of mixing natural gas with liquid water to form a stable water crystalline ice-like substance. NGH transport is believed to be a viable alternative to LNG or pipelines for the transportation of natural gas from source to demand [10–12].

GtS involves three stages: production, transportation and re-gasification, e.g. Fig. 2. NGH is created when certain small molecules, particularly methane, ethane and propane, stabilise the hydrogen bonds within water to form a three-dimensional cage-like structure with the gas molecule trapped within the cages. A cage is made up of several water molecules held together by hydrogen bonds. These types of structures, known as clathrates, have been well studied and are complex [10,11]. The thermodynamics and phase diagrams of water, hydrate and various gases have all been researched and documented [10]. Hydrates are formed from natural gas in the presence of liquid water provided the pressure is above and the temperature is below the equilibrium line of the phase diagram of the gas and liquid water. The solid has a snow-like appearance.

Mostly in the oil/gas industry, NGH is a pipeline nuisance and safety hazard, and require considerable care by the operators to ensure that they do not form as they can block pipelines if precautions, such as methanol injection, are not taken [3,10]. On the other hand, vast quantities of gas hydrate have been found in permafrost and at the seabed in depths below 500 m (1500 ft), and if properly exploited could become the major energy source in the next 30 years. However, extraction at the moment is only at an early research stage and much more work is needed before production is safe and commercial [2,10,13].

For gas transport, NGH can be deliberately formed by mixing natural gas and water at 80–100 bar and 2–10 °C. One research process group has described the process simply as 'just add water and stir' [12]. It has been found that if this slurry is refrigerated to around −15 °C, it decomposes very slowly at atmospheric pressure, so that the hydrate can be transported by ship to market in simple insulated (inexpensive compared to LNG carriers) bulk carriers, i.e. a large 'thermos flask' under near adiabatic conditions.

At the market, the slurry is melted back to gas and water by controlled warming for use after appropriate drying in electricity power generation stations or other requirements. The hydrate yields up to 160 sm^3 of natural gas per tonne of hydrate, depending on the manufacture process [12,14–16]. The manufacture of the hydrate could be carried out using mobile equipment for onshore and ship for offshore using a floating production, storage and offloading vessel (FPSO) with minimal gas processing (cleaning, etc.) prior to hydrate formation, which is attractive commercially. The water can be used at the destination if there is water shortage, or returned as ballast to the hydrate generator and, since it is saturated with gas, will not take more gas into solution. Process operability of continuous production of hydrate in a large scale reactor, long-term hydrate storage and controlled regeneration of gas from storage have all been demonstrated. Reactor and process data have been obtained and equipment design for full-scale process development outlined [12,14–16]. A pilot plant producing 1 tonne of hydrate (transporting around 5000 scf gas) has been recently demonstrated [12].

The hydrate can be stored at normal temperatures (0 to -10 °C) and pressures (10 to 1 atmosphere) where 1 m^3 of hydrate should contain about 160 sm^3 gas per m^3 of water. This 'concentration' of gas is attractive as it is easier to produce, safer and cheaper to store compared to the 200 sm^3 per 1 m^3 of compressed gas (high pressure >3000 psig) or the 637 sm^3 gas per 1 m^3 of LNG (low temperatures of -162 °C). This efficient storing of gas in the hydrate state is due to the molar ratio of gas to water and to the exceptionally high density of gas in the hydrate state, and in fact the relative density of the gas in the hydrate lattice exceeds its liquid state density. Gas storage in hydrate form becomes especially efficient at relatively low pressures where substantially more gas per unit volume is contained in the hydrate than in the free state or in CNG when the pressure has dropped. When compared to the transportation of natural gas by pipeline or LNG, the hydrate concept has lower capital and operating costs for the movement of quantities of natural gas over adverse conditions. The lower cost difference is significant and the simplicity and flexibility of the process should make GtS worth the development required.

In summary, hydrate is very effective for gas storage and transport as it eliminates low temperatures <162 °C, and the necessity of compressing the gas to high pressures (>3000 psig). Dry hydrate pellets yield about 160 (ideally 180) m^3 of gas at standard conditions from 1 m^3 of hydrate [12], compared to the 637 sm^3 per 1 m^3 of LNG. Although, this is a considerable volume penalty (and hence transport cost) if considered in isolation, with the cheaper ships for hydrate transport the process could be economic [12].

5. Transporting the gas energy as power, GtW

Currently, much of the transported gas's destination is fuel for electricity generation, but electricity can be generated anywhere, particularly at or near the reservoir source and transported by cable to the destination(s) (gas-to-wire, GtW). Thus for instance offshore or isolated gas could be used to fuel an offshore power plant (may be sited in less hostile waters), which would generate electricity for sale onshore or to other offshore customers. Unfortunately, installing high-power lines to reach the shoreline appear to be almost as expensive as pipelines [2], so that GtW could be viewed as defeating the purpose of an alternative cheaper solution for transporting gas. There is significant energy loss from the cables along the long distance transmission lines, more so if the power is AC rather than DC; additionally, losses also occur when the power is converted to DC from AC and when it converted from the high voltages used in the transmission to the lower values needed by the consumers [2]. Some consider having the energy as gas at the consumers' end gives greater flexibility and better thermal efficiencies, because the waste heat can be used for local heating and desalination. This view is strengthened by the economics as power generation uses approximately 1 million scf/day of gas for every 10 MW of power generated, so that even large generation capacity would not consume much of the gas from larger fields, and thus not generate large revenues for the gas producers. Nevertheless, GtW has been an option much considered in the US for getting energy from the Alaskan gas and oil fields to the populated areas, particularly California.

There are other practical considerations to note such as if the gas is associated gas, then if there is generator shutdown and no other gas outlet, the whole oil production facility might also have to be shut down, or the gas released to flare. Also, if there are operational problems within the generation plant the generators must be able to shut down quickly (in around 60 s) to keep a small incident from escalating. Additionally, the shutdown system itself must be safe so that any plant that has complicated processes that requires a purge cycle or a cool-down cycle before it can shut down is clearly unsuitable. Finally, if the plant cannot shut down easily and/or be able to start up again quickly (perhaps in an hour), operators will be hesitant to ever shut down the process, for fear of financial retribution from the power distributors.

There is a new GtW proposal in the UK; suggestions have been made to North Sea operators that gas could be piped ashore, power generated onshore at much higher levels of efficiency and then sent by cable to the operating platforms. It could replace on-board power generation using diesel or lower efficiency gas turbines. The overall benefits could include reduced greenhouse gas emissions, health hazard reductions by eliminating a significant source of noise, safety improvement by not burning gas onboard, freeing space on the platforms for other equipment and less offshore operating staff; thus platform costs would be reduced. These reduced operating costs could enable the field life to be extended deferring decommissioning costs. Schemes like this may well be considered for other oil/gas provinces if the pilot proves successful.

6. Transporting the gas as a liquid, GtL

In gas to liquids (GtL) transport processes, the natural gas is converted to a liquid, such as syncrude methanol, ammonia, etc., and transported as such. Methane is first mixed with steam and converted to syngas ($CO + H_2$) by one of a number of routes using suitable new catalyst technology (all heavily patented) [1,2]. The syngas is then converted into a liquid using a Fischer Tropsch process (originally in the presence of an iron or cobalt catalyst) or an oxygenation method (mixing syngas with oxygen in the presence of a suitable catalyst). The produced liquid can be a fuel, usually a clean burning motor fuel (syncrude) or lubricant, or ammonia or methanol or some precursor for plastics manufacture (e.g. urea, dimethylether (DME)—which itself is also used as a transportation fuel, LPG substitute or power generation fuel as well as a chemical feedstock) [1,2]. The liquid is shipped in a suitable tanker.

Methanol is a GtL option that has been in commission since the mid 1940s. Trinidad is a major world contributor, with some 5 plants, and 3 to come on stream, currently producing around 8500 tonnes of methanol per day and using 290 million scf/day of natural gas [4]. While methanol produced from gas was originally a relatively inefficient conversion process, optimised technology has improved the efficiency to 30–35 million Btu per tonne methanol (from over 50) so that there is now a larger output per unit of capital invested. Methanol can be used in internal combustion engines as a fuel, but the current market for methanol as a fuel is limited, although the development of fuel cells for motor vehicles may change this. Methanol is best used as a basic chemical feedstock for the manufacture of plastics [1].

Other GtL processes are being developed to produce clean fuels, e.g. syncrude, diesel, or many other products including lubricants and waxes, from gas but require complex (expensive) chemical plant with novel catalyst technology [1,2]. Most of these processes are currently only in their pilot stage, although Malaysia has had a commercial plant producing 12 000 bbl/day of clean middle distillate fuel since 1996 [2], and the State of Qatar may soon be producing clean fuels commercially this way [5], and Trinidad and undoubtedly others are deep in negotiation [4]. At the moment such premium fuels are expensive compared to normal fuel oil, but are environmentally much cleaner due to the absence of sulphur components, because these components are removed during the initial processing stage of the recovery of natural gas from the reservoir. Clean fuels may become mandatory in some downtown parts of cities to reduce poisonous pollution problems. The investment and size of plants to replace all gasoline by gas-oil produced by GtL would be currently prohibitive, even if the technology had been fully developed, but if a new process (including novel catalysts) could be found this gas transport energy scenario could rapidly expand.

7. Transporting the gas energy as a chemical commodity

The components in natural gas, methane, ethane, propane, *n*- and iso-butanes and pentanes are all useful in their own right. The higher paraffins are particularly valuable for a wealth of chemicals and polymer precursors such as acetic acid, formaldehyde, olefins, polyethylene, polypropylene, acrylonitrile, ethylene glycol, etc., as well as portable premium fuels, e.g. Calor gas (propane) [1]. As discussed in Section 6, methane can be converted via syngas to methanol, ammonia, syncrude, lubricant, or some precursor for chemicals manufacture, e.g. dimethylether (DME), urea, etc., and then used to make chemicals for export. The technology to manufacture these molecules from gas, particularly from methane, is still developing and requires novel research into catalytic processes and then large scale development with huge investment, but commercial advancements are expected in the next decade [1].

8. Transporting the gas energy as a commodity, gas to commodity (GtC)

Commodities such as aluminium, glass, bricks, cement and iron bars all require large quantities of energy in their making. With GtC, the gas is converted to thermal or electrical power, which is then used in the production of the commodity, which is then sold, on the open market. It is the energy from the gas, heat via electricity or direct combustion, and not the components, as discussed in Section 6 for the GtL and Section 7 for the polymers and plastics, that is used. The gas energy is, in essence, transported via the commodity, but there are many market risks as discussed below.

9. Market risks for transport of gas

9.1. GtL and GtC risks

The cost of GtL and GtC plants is very high (possibly muti-billion US$) and raw materials for conversion to commodities, e.g. bauxite, silica sand, limestone, etc., may be difficult to import to site with reliability. Therefore, much thought has to be given before embarking on the project(s) and monetising the gas by these routes. Planning for GtL and GtC has to consider many aspects and there are many difficult questions needing answers:

- are there market opportunities? Can the commodity be able to capture a market share and be cost competitive? Are there other countries planning similar projects, and if so would the demand worldwide for the commodity be saturated? Is the selling price of the commodity volatile? Can the commodity price fluctuations be carried?
- what are the operating, raw material, electricity and labour costs and thus, the cost of producing the commodity as compared to the selling price? i.e. what is the margin?
- can long-term contracts be negotiated, or will there always be uncertainty in getting sales?
- what gas price is economical to the commodity producer? Is this the best way to sell the gas for the producer?
- what is the real total cost of the investment in the plant, e.g. cost of new smelters?
- is selling the commodity, which is essentially selling energy, getting a satisfactory rate of return for the energy sold this way—are the benefits greater than simply selling the gas?
- is there a downstream local industry capable of adding value to the commodity, e.g. manufacture of car components using aluminium, aluminium cans, kitchen utensils, glass bottles, reinforced concrete members, etc?
- could there be increased local employment, particularly downstream, or is there insufficient population? Is there unemployment in the country? Downstream development using the commodity locally by the local population might be very helpful in relieving unemployment. (It has to be remembered that the upstream development to monetise the gas will not help reduce unemployment as it is a small employer, and the number of employees being continually optimised (usually reduced) to keep the unit production cost to a minimum and competitive, particularly if the oil price drops.)
- is this a good way of industrialising the country, or is the country just acting as the heavy industrial site for the more developed countries?
- what is the real environmental impact of the project?
- and finally, 'Is the investment in the upstream part of the chain giving benefit to the country, and if so in what way, e.g. increased employment, revenue, etc?'

Until these questions have been fully assessed by a nation no progress can be made. The problems of global market stability after September 11th 2001, and product redundancy (e.g. the MTBE bans in the State of California) or WTO rulings (e.g. steel quotas) reduce confidence in going ahead with GtC technology. Trade embargos, product dumping, terrorist actions, war and political instabilities can very quickly make a good project which should create wealth and jobs for the gas rich country become a failure.

9.2. Competition with large scale LNG

The current large LNG projects have contracts typically for up to 20 years and, once they have been carefully planned, marketed and built, are expected to provide stable revenues over this time period, and would cushion shorter term fluctuations in other parts of an oil field development (e.g. oil price variations). As much has already been invested in LNG, if LNG has been established competition by GtS or CNG with LNG for expansion of gas sales to the same destination is unlikely. For green site developments and smaller niche markets, GtS or CNG could be strong contenders, e.g. Indonesian islands, or where portable process equipment can be brought onto site, e.g. associated gas, and then used until either pipeline facilities or other infrastructure are built, or where the gas production rate is too variable or drops below a certain value to be economic for LNG. Clearly, if hostile government or terrorist activity could occur, a project that is less costly, with less vulnerable plant would be favoured from an insurance point of view, particularly in terms of equipment loss. Clearly, very detailed site and route specific analysis would be needed.

Economic models have been developed for the entire supply chain for bulk gas transportation of CNG, GtS, GtL for both on- and off-shore production facilities and comparisons made with large scale LNG projects [17,18]. The GtS hydrate plant is often quoted to have capital costs much lower than for LNG perhaps half [12,14–16] and CNG even less [6,17]. Consequently, the payback period will be shorter for the same gas throughput. GtL technology is currently under rapid development, but likely to be as costly as LNG although the true costs will depend on the volumes of gas being processed and particularly the premium value of the product [1].

Calculations of which is the better (cheaper and cost effective) transport scheme are fraught with danger of not always comparing like with like, ignoring the risks of higher capital borrowing for a more complicated process, differences in technical difficulty and maintenance costs as well as local idiosyncrasies. Although projects are location specific, the process vendors of large scale CNG and GtS demonstrate that their particular process is cheaper than LNG for similar duties for a green site plant of, currently, 500 million scf/day of gas [7,9,12,16]. Other comparisons can be made on the capital cost of the whole plant, the risks of exposure to the investors or payback time but sometimes not much mention is made of increased operating costs and general mechanical complications of ageing plant, plant upgrades during the lifetime of the project, improved technical advances making the plant redundant or the product cheaper elsewhere or political difficulties. Thus contract negotiators have to be very wary when preparing the long-term contracts!

It must be remembered that 1 bbl oil contains approximately the same amount of energy as 6000 scf (170 m^3) of gas, so that if the oil price is $ 15/bbl then at equivalent energy rates, gas should sell at approximately $ 2.5/million scf if the gas is just energy for power generation. Calculations need to be made on the costs per bbl oil equivalent for delivery from reservoir to the customers' jetty. For example, the first train in the State of Qatar these costs were estimated to be equivalent to $ 15.6/bbl oil, or $ 2.7/thousand scf gas (consisting of upstream costs $ 2.2/bbl, liquefaction costs, $ 7.6/bbl, transport costs $ 5.8/bbl) [19]. Thus when the oil price is at $ 20/bbl LNG is a cheaper energy source, but when at $ 10/bbl oil is cheaper. Transport and liquefaction costs for LNG account for ~85% of the supply cost of delivered LNG to the customer's jetty. Additional costs occur to get the gas from the jetty via gasification to the burner tip. In Qatar's case condensate (ethane–pentane) sales from the gas lowered the overall train costs, but not all natural gas contains such significant quantities of condensates. Thus the costs, even for LNG, are site and gas composition specific.

9.2.1. Effects of reduced manufacturing complexity

The hydrate and CNG processes do not involve extreme temperature, either high or low, do not require an oxidant or a catalyst, nor feature any complex unit operations other than standard process equipment. In addition, the technology is able to cope with an intermittent and variable profile of gas production with time, as is usually the case with associated gas.

9.2.2. Niche markets

Although it is believed [4,7,9,12,16] that the delivered cost of gas by GtS or CNG can compete in the energy market at any scale compared to LNG, by focusing on a niche, for instance offshore associated gas, remote reservoirs, smaller reservoirs or stranded onshore gas, they may create markets. The actual economics of gas transportation can become one element of a much bigger scenario with the extreme example being where an oil development may not proceed if there is no means to dispose the associated gas and flaring is prohibited. Selling, and hence exporting, the gas by GtS or CNG may ensure that an oil project can be commercially successful.

9.3. Small scale gas fuel application, e.g. tourist industry and hotels

We have not yet considered the small volume needs of, for instance, the Caribbean, Black Sea, Indonesian and Mediterranean tourist industries. This industry is using increasing quantities of electricity but will have only a 'small' energy demand on the world scale. A large five-star hotel which may use perhaps 11 million-kW h of electricity per year, would need only some 70 million scf/year of gas (~200 thousand scf/day) (remembering that 10 MW of electricity generating capacity continuously running requires ~1 million scf/day of gas). If generated continuously, the hotel would need only a ~1.2 MW generator (30 000 kW h/day of electricity) although because the demand is variable during the day, the generating capacity would be larger and not always on 100% output, which is an inefficient use of equipment, although an insurance for a reliable supply.

The quantity of 100 thousand scf/day is 45 million scf/year, and is only 10% of input to one 500 million scf/day train of LNG for 1 day, i.e. a very small volume. (It is equivalent to about 7500 bbl fuel oil per year.) This gas sale would only generate an income of perhaps $ 0.1 million US at $ 2.5/thousand scf—a very small income generator for any major gas transporter. However, such small volumes of gas are available as stranded gas, or possibly from flaring prohibition of associated gas in fields not connected to a major LNG facility, and may be transported profitably if acceptable prices can be negotiated if the 'right' technology is available.

Transporting these sorts of small quantities of gas are trivial compared with the large LNG trains, and in principle should be relatively easy for GtS or CNG and not need the huge expensive specially-built ships. But there will be significant development initialising costs. The manufacturing of hydrate could be carried out using mobile equipment for onshore and ship for offshore, or for CNG with a mobile compressor, so that the equipment can be moved on if the field ceases production. If standard equipment and procedures could be developed worldwide then a profitable and successful small volume gas transport market could be developed. Development costs would have been adsorbed in the initial projects. Even so the market would be small and localised, but would give the hotels a 'green' benefit. May be too, if the gas being transported is associated gas, it would give an operating capability to the oil producer (oil production is allowed), rather than closed in by a gas flaring restriction.

The real margins to the transporter will be small because of the small volume sales, and would currently be unlikely to be economically attractive to any major gas seller/transporter unless it is part of a larger project, such as disposing of associated gas as mentioned above, and the field not be allowed to produce without gas export. But it could appeal to a local entrepreneur. The competitive advantage of the GtS or CNG processes over other non-pipeline gas technologies, particularly GtL, is that they are intrinsically simpler processes and, as a concept, far easier to implement. These processes are feasible at lower capital costs, and hence require smaller investments and payback times for equivalent gas sales. Another commercial advantage that GtS or CNG has over LNG is that to implement a project a much smaller lead-time is needed, which means that GtS or CNG are producing revenue whilst the LNG needs more years of investing (larger) capital before any return. They are also smaller insurance risks.

9.4. Environmental considerations

Fuel oil produces more CO_2 for the same energy output than gas, and the environmental costs is higher per tonne of CO_2 emitted. Thus from this point of view, electricity generated by gas transported by CNG, hydrate or even LNG in small containers, could possibly be cheaper than fuel oil at say, \$ 30/bbl, i.e. \$ 5/thousand scf gas, particularly if there are extra costs for exhaust clean-up and increased boiler corrosion and environmental carbon tax.

9.5. Alternative energy

Finally, there is the ultimate solution where an 'alternative' energy of solar, wind or wave power conversion is used. This is totally green. Gas would be used only for commodity production or chemical needs for exporting globally via GtL and GtC. This must surely happen one day, but in the meantime perhaps power via gas transported by GtS or CNG is the answer, particularly for stranded gas.

10. Conclusions

- Gas needs to be sold to monetise it. At present, only pipelines and LNG are the 'gas as fuel' transport routes. Pipeline costs are approximately proportional to distance. LNG transportation costs also increase proportionately with distance to market, but at a less steep rate, but have heavy initial investment needs and large volume quantum jumps of LNG when a new train is brought into the market. GtW, GtL and particularly GtC have potential, but there are huge plant investment costs, commodity price fluctuations and marketing implications which hinder development progress. GtW can have large energy losses.

- Gas energy movement, methods and quantities will depend on market demands and distance to market. What will sell and what contracts can be negotiated for long-term gas reservoir and infrastructure development, including the necessary manufacturing and processing plant is critical. Pipelines, LNG and probably to some extent GtL, have a large economy of scale, so that they are proportionately expensive for developing small gas reserves. LNG production is expensive (around US$ 15/bbl oil equivalent—$ 2.5/thousand scf) and many exporters do not have the quantities of gas to export, or importers do not have the need nor the capital to build the storage and regeneration facilities for importing such large quantities.
- Small volumes of intermittent gas are not economically attractive to the major gas sellers, particularly for LNG facilities or pipelines. For the smaller markets, e.g. islands where pipelines or LNG are not feasible, GtS and CNG can be economic potential transport methods. The quantities can be far better regulated and designed for the needs of a particular power station. There could be options for handling niche markets for gas reserves which are stranded (no market) and for associated gas (on- or off-shore) which cannot be flared or re-injected, or for small reservoirs which cannot otherwise be economically exploited.
- Transportation of natural gas as hydrate or CNG is believed feasible at costs less than for LNG and where pipelines are not possible. The competitive advantage of GtS or CNG over the other non-pipeline transport processes is that they are intrinsically simple, so should be much easier to implement at lower capital costs, provided economically attractive market opportunities can be negotiated to the gas seller.
- Ultimately though, it will be the cost per therm of the gas and the profit margin between the cost of gas and the sold product. This may be tempered when there are obligations of an energy richer country towards its poorer neighbours (for example Trinidad and the other Caribbean nations, or the various non-energy producing Indonesian islands).
- Finally, governments and companies have to take not only the economic risks into account, but also terrorist activity, political changes and trade embargos over long periods of time before deciding on any of these expensive, but possibly very rewarding gas transport projects.

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Appendix A. Units

The energy industry uses a variety of units. Conversion from one unit to another is often necessary. The major definitions and conversions useful for this paper are: thousand = 10^3; million = 10^6; billion (B) = 10^9; trillion (T) = 10^{12}.

Gas volumes: 1000 scf = 28.30 sm^3, with standard conditions represented by scf and sm^3, and are 60 F and 14.7 psia and 15 °C and 1 bar, respectively; 35.3 scf gas = 6.29 sbbl≡1 sm^3; 10^6 scf gas / day≡10×10^6 sm^3 gas / year≅7500 metric tonnes LNG / year. Also, 6000 scf gas contains approximately the same energy as 1 bbl oil, and when gas costs $ 1.00/thousand scf, the oil cost energy equivalent is $ 6.00/bbl (boe barrel of oil equivalent); and 7.5 bbl oil ~1 metric tonne oil.

Power: MW = megawatt = 10^6 W; 1000 W h = 3412 Btu; 100 000 Btu≅100 scf of gas≅1 therm. Electricity generating capacity continuously running requires ~1 million scf gas/day for 10 MW.

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