Small-scale GTL: back on the agenda

Small-scale GTL has a bright near-term future, if it is applied to associated gas from “stranded” oil deposits, argues Iain Baxter, director of Business Development, at CompactGTL.

Gas-to-liquids (GTL) has begun to re-emerge as a prominent topic in the oil and gas community. The commissioning of Shell’s giant Pearl Qatar plant, plans by Sasol for large plants in North America and Uzbekistan, a record arbitrage between liquids and gas commodity prices and the emergence of recoverable shale-gas resources, many of them remote, have contributed to the debate.

Implementation of further large-scale GTL plants in the near future seems almost certain. At capacities of 30-100 million barrels a day (b/d) and upwards, projects exhibit economies of scale which de-sensitise them to commodity price and project cost uncertainties. But what about small-scale GTL?

A number of small-scale GTL technologies have been conceptualised with varying degrees of success. However, none has yet been converted into a commercial project. One reason is the inherently high capital cost and complexity of GTL. High costs derive from exotic construction materials, high design temperatures, aggressive or corrosive environments and the use of specialised catalysts at all stages of the process. In the absence of economies of scale, small GTL attracts higher capital cost estimates per barrel of capacity. This can depress project internal rate of return (IRR) and increase sensitivity to market changes, making it difficult to realise attractive project proposals.

When CompactGTL was established in 2006, the company soon concluded that the first commercial opportunities for small-scale GTL were likely to be for conversion of associated natural gas at remote and offshore oilfield locations – so-called “stranded oil”. Many oilfield development scenarios generate compelling economic projects for small-scale GTL, where the process is able to convert small volumes of otherwise problematic associated gas.

Understandably, small-scale GTL is often linked to monetising stranded gas. Unfortunately, this still seems a fair way from becoming a reality. Disproportionately high costs for small plants provide one reason, but there are other factors that are rarely discussed. One is the investment required for the stranded-gas field development itself. It is not just the GTL plant costs that need to be recovered by GTL liquids production, but also the costs associated with the drilling, establishment and operation of a field in a remote location with no infrastructure. Another factor is production decline, which is difficult to mitigate in a remote field. Gas processing equipment rarely accommodates more than 50% turn-down. Even if production at 50% capacity is maintained for several years of field life, the capital employed for the GTL plant reflects its nameplate capacity.

Associated gas issues frustrating oilfield development have been independently researched and verified by Wood Mackenzie and Fugro Robertson, following studies commissioned by CompactGTL (Figure 1). There are over 800 oilfields worldwide, mainly with a low gas-to-oil ratio (GOR), giving gas flow rates less than 50 million cubic feet a day (cf/d), which represents a huge market.

Dealing with associated gas at remote locations poses fundamental challenges to the oil company, where there is no commercially viable or technically feasible market for the gas or other disposal methods. Historically, this is why large quantities of gas have been flared. However, with the right technology, small-scale GTL can be used to convert associated gas into synthetic crude oil (syncrude) at the point of production, eliminating flaring. The syncrude is then mixed with the naturally produced crude at the oilfield and exported to market. This transforms oilfield economics and the GTL solution becomes a project enabler, allowing the oil company to proceed with development and unlock oilfield value. This also reduces reliance on third parties and third-party infrastructure. The oil company unilaterally regains control over its own project and converts what was a liability into an asset, since the associated gas volumes can be booked as reserves.

In contrast to traditional gas disposal routes, small-scale GTL deployed in this way represents a paradigm shift and offers the oil company additional crude oil revenue whilst addressing flaring legislation. It requires no fixed external infrastructure development, no additional product transportation or market access needs and poses no risk of reservoir damage through re-injection. The national government and/or national oil companies benefit through increased oil tax revenues or production sharing and its natural resources are better utilised.

Other gas processing technologies, such as liquefied natural gas (LNG), compressed natural gas (CNG) or methanol should not be regarded as comparable to small-scale GTL: they do not address the same market. The high investment and infrastructure required for LNG and CNG require high flow rates of gas (typically more than 200 million cf/d) to provide positive economics. CNG costs rise dramatically with distance to market, and, in common with LNG and methanol conversion, it is dependent on establishing separate storage and transportation infrastructure to access markets for the product.

With small-scale GTL, because the end product is crude oil (a mixture of crude with a small quantity of miscible syncrude), the oil company has a single, easily accessible market for the product, requiring no separate storage or transportation, irrespective of the oilfield location. Alternatives to gas flaring at these volumes are (i) pipeline export, (ii) electricity generation, or (iii) gas re-injection into the reservoir. These still attract significant capital expenditure and entail logistical and operational difficulties, yet deliver little or no value in return. Where gas is exported by pipeline, or electricity by transmission cable, negligible value is obtained at the point of delivery in regions such as Russia and Africa, and protracted commercial negotiations are often required with the buyer, depressing project net present value (NPV).

CompactGTL’s solution

Following an extensive commercialisation programme, CompactGTL’s solution to the problem of associated gas at remote oilfields, both onshore and offshore, can now be applied to projects around the globe that are delayed, constrained or prevented by operational matters, logistical issues or gas flaring legislation.

As an integral part of the commercialisation process, to meet demand for multiple projects, the company has forged strategic partnerships with world-class groups to form a robust supply chain. Partners include Sumitomo Corporation, SBM Offshore and Fluor Corporation. Advanced commercial plant
designs have been completed including full integration with floating production, storage and offloading (FPSO) systems. A crucial feature of the CompactGTL system, unlike other gas conversion technologies, is its modular nature, which allows the matching of the equipment to the quantity of associated gas and gives effective “turn down” of the process if gas flow declines over time. The modular design, with mass-produced and containerised reactor modules, enables rail car transportation and installation at remote sites with poor infrastructure.

CompactGTL is the only company to have successfully demonstrated and operated a complete, modular GTL technology that is suitable for deployment at remote locations. Uniquely, the CompactGTL process has been publicly approved and qualified, in January 2012, by Brazilian state-controlled oil company Petrobras. This followed an extensive joint testing programme in Brazil where the reliability, stability and robustness of the process were all proven on a commercial demonstration plant (see top image). The plant incorporates all aspects of the commercial CompactGTL process, including gas pre-treatment package, process steam generation, syngas compression and tail-gas recycling.

The key steps in the CompactGTL process are similar to conventional GTL. The feed gas is first conditioned to remove contaminants such as chlorides and sulphur. A pre-reformer then reacts the higher hydrocarbons to give methane, hydrogen and carbon monoxide. Proprietary steam methane reforming (SMR) modules, operating at 650-770°C, at 4 bar, convert the methane-rich stream, producing hot syngas (H₂ and CO). A waste-heat boiler cools the syngas, generating the steam required for the SMR process. The syngas is then compressed to 25 bar to feed the Fischer-Tropsch (FT) process. Pressurised water maintains the proprietary FT reactor modules at a highly uniform temperature of typically 225°C. FT by-products include carbon-rich and hydrogen-rich tail gas streams. The carbon-rich stream can be recycled back to the pre-reformer to boost the overall carbon-conversion efficiency and hence the syncrude yield. The extent of this recycle is a key plant design variable that is optimised depending on project specific drivers such as plant footprint constraints and alternative tail gas utilisation opportunities. The hydrogen-rich stream is mixed with fuel gas for ancillary gas turbines. A further benefit of the CompactGTL SMR process is the ability to handle up to 35% carbon dioxide (CO₂) in the feed gas, without additional treatment, as associated gas sometimes contains high CO₂.

Reactor module size and weight are key to making this process workable in remote or offshore oilfields. For a given throughput, the CompactGTL SMR and FT reactor modules, due to exceptionally high heat-transfer characteristics, are approximately one tenth of the size of their conventional GTL counterparts. This is achieved using brazed plate and fin heat exchanger construction, which benefits from established high-volume manufacturing techniques.

Fugro Robertson independently conducted economic case studies looking at sample oilfield projects. Figure 2 shows the summary results for an onshore oilfield, where crude production would otherwise be shut-in by an inability to flare or export gas. It should be stressed that the cash flow shown is the result of an incremental analysis – that is production with, versus production without, GTL implementation. This gives rise to the unusual look of the cash-flow chart. This is in a Nigerian setting, with a typical tax regime of 15% royalties and an 85% tax rate. The novel feature of this scenario is how the GTL plant not only generates extra revenue from the syncrude derived from the associated gas, but also “liberates” additional conventional crude production. This brings forward oil production from the reservoir. The GOR in this case is 1,000 with an initial associated gas flow rate of 12 million cf/d. The GTL plant converts associated gas into 1,000 b/d of syncrude, which augments oil production. The economic return here derives mainly from the brought-forward natural crude and the ability of the oilfield operation to continue, despite flaring restrictions. An incremental NPV10 of $81 million is achieved with cash payback within three years. The economics are not particularly sensitive to GTL capital expenditure (capex) or operating expenditure (opex). In this example, some GTL capex has been converted to opex by modelling the long-term lease finance of the SMR and FT reactor modules, thereby improving cash flow.

Examining a potential offshore development for a deep-water discovery, within the Australian fiscal regime, also yields positive economics. Reserves are estimated at 150 million barrels of oil with a peak production rate of 45 million b/d. With a GOR of 500, 12 million cf/d of associated gas is produced after deducting FPSO fuel demand. Without GTL, gas disposal would be achieved by re-injection at a capex of $75 million for well completion, $40 million subsea costs and $40 million for compression, giving a total of $155 million. If this capital spend is instead directed at a GTL facility integrated with the FPSO, then additional oil production (syncrude) of 1,000 b/d is achieved for little incremental cost. The resulting project economics are attractive, with an IRR of over 90% on the incremental capex and a maximum exposure of $33 million. Again, lease finance of the reactor modules is assumed.