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Fiscal Solutions for Gas Exploration & Production

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Background

Gas is clean, abundant and reliable. It is 30% less carbon intensive compared to oil, and 50% less carbon intensive compared to coal. The availability of gas resources is growing, as evidenced by the unconventional gas revolution in North America as well as new play discoveries in the Eastern Mediterranean & in East Africa. In addition to this, gas is a reliable source of energy –available when the sun doesn't shine and when the wind doesn't blow.

The good news is that gas will play an increasingly dominant role. In 2040, gas will be the second-largest fuel in the global energy mix, after oil[i]. Amidst this industry shift, sound policies and regulations are imperative. These will ensure that the resource is developed in a sustainable and efficient manner.

Aim

This paper explores policy and regulatory approaches that are key to successful upstream gas developments.

Methods

We cover this topic in 3 parts:

1-Getting the Basics Right: We first understand the bare essentials required of a successful gas development.

2-Designing Bespoke Incentives: We then explore variations tailored for different kinds of developments, namely unconventional gas and marginal gas.

3-Anticipating Future Challenges: Finally, some of the largest gas-prone areas lie in territorial dispute areas. To unlock these resources, we explore the framework for gas in a disputed area, a subject that is likely to be very relevant in the future.

Results

1 - Getting the Basics Right

First and foremost, we need to recognize that gas is different from oil and design specific mechanisms that address this. Two key distinctions differentiate gas from oil:

1. **Tradability**

   Relative to oil, gas is not as easily exchangeable between producer and end user. Gas producers need to secure a market and an evacuation route, which connects the seller and buyer. It makes little sense to develop a gas field if there are no means to monetize.

   Gas developments require highly specific infrastructure, so they are less flexible compared to oil developments. In 2012, 57% of globally traded gas was transported via pipeline. Gas producers need to lock in a target market. This decision cannot be reversed (one cannot re-route a pipeline to an alternative market) so it is imperative that a long-term contract is established. The remaining 43% of gas was delivered to gas consumers via LNG. LNG provides a bit more flexibility than pipelines. However LNG buyers still require regasification terminals and LNG sellers require liquefaction facilities.

   The provision of gas-friendly contract features is a mitigating solution.

   If a non-associated gas discovery is substantial, an E&P company can be allowed via a **Gas Holding Period** to hold a gas field for several years to identify a viable gas market. In Malaysia, there is a retention period of five years for a gas discovery from the end of the exploration period to the start of development for these purposes.

   The growth of the gas market requires predictable and bankable demand. Once a target market is identified, companies then lock in sales for a guaranteed number of years. E&P players require assurance that their specialized, irreversible investments can be efficiently utilized. This issue is addressed via long-term **Gas Sales Agreements** that remove the uncertainty associated with these investments. Pipelines of an optimal size are constructed because buyers have secured their demand requirements "up-front".

   Gas players typically need to construct significant midstream capacity. Hence a **longer development period** is allowed for gas projects (6 years) compared to the equivalent for oil projects (4 years). In Algeria, non-associated gas fields enjoy a longer exploitation period: 30 years vs. 25 years for conventional oil/ associated gas fields.

2. **Energy density**

Gas contains less heat content compared to oil. It is a "high-volume, low-value" commodity. Generally, crude oil contains 1.01 Million British Thermal Units (MMBtu) per cubic feet while gas contains 0.18 MMBtu per cubic feet. So to increase the temperature of one pound of water by one degree Fahrenheit, we would need 6 times more gas compared to oil.

Commercial terms, which are more attractive than those of oil projects, will incentivize E&P players to pursue gas developments. Some countries acknowledge this reality and offer different fiscal incentives for gas projects compared to oil. Examples include:

a) Lower tax rates or tax exemptions in Trinidad & Tobago, Nigeria, Tunisia, Vietnam, Papua New Guinea & Russia.
b) Higher cost-recovery ceilings or profit shares in Egypt, Indonesia & Malaysia. Higher cost recovery ceiling will allow contractor to recover costs earlier, shortening time to breakeven. Higher upfront cash flows improve the net present value.
c) Cross-flow in Nigeria & Malaysia. Gas-related capital expenditure can be recovered against crude oil income.

The industry must move away from **pricing models** in which companies are assigned prices by the government rather than paying customers. A study released by the IGU in 2014 revealed that 38% of global gas demand was priced based on non-market factors, primarily determined by a regulatory authority. Low, fixed natural gas prices for domestic consumers have long reduced the incentive for companies to produce gas over and above that associated with oil production. In addition, while consumer affordability is a key priority for many governments, it does little to incentivise the efficient utilisation of gas.

An example of gas reform to watch is that of China. The Middle Kingdom needs to address several issues in its pursuit to promote more gas consumption in its energy mix. Gas pricing is a major obstacle. Historically, domestic gas prices have remained low while China becomes increasingly dependent on expensive gas imports. This raises the average cost of gas supply to China in spite of there being cheaper alternatives available. It also fails to incentivize domestic gas development, particularly that of China's unconventional resources. The cost-plus approach is another problem: gas price is determined at individual development level based on cost per field plus an agreed margin negotiated between buyer & seller. In 2013, gas prices increased substantially as a result of a price reform. This reform takes a netback approach based on oil price indexation. Gas price is estimated to increase by more than 50% from US$ 8.1/MMBtu pre-2013 reform to US$ 12.8/Mmbtu in 2015[ii]. Other countries to watch are Russia and Iran, which have seen a gradual shift away from subsidized gas pricing below cost.

In summary, to promote gas developments, we acknowledge the unique characteristics of gas with regards to tradability and energy density. In view of this, we then design policy and regulations that address these intricacies. Contract features, commercial terms and gas prices form the basic building blocks to ensure a successful gas development.

2- Designing Bespoke Incentives

In the previous section, we addressed the basic building blocks we can put in place to incentivize gas developments. We now observe bespoke incentives, specifically tailored for different kinds of gas-related challenges.

1. **Unconventional Gas**
   Unconventional gas will account for 60% of new gas supply over the next 25 years[iii]. The pace and sustainability of this industry shift depends on policy and regulatory incentives designed specifically to address unconventional developments.

   Incentivize Frontier Area Development

   Gas players face huge risks in developing frontier unconventional plays. Looking to the US as an example, we see that fiscal incentives successfully promoted unconventional developments. Tax credits by the government for CBM and tight gas contributed to an increase from 8% to 30% of Lower 48 gas production from 1982 to 2001[iv].

   The unconventional gas industry remains relatively nascent outside the US. Several fiscal incentives have been put in place to progress this area:

   a) **Lower royalty rates for shale gas & CBM in Alberta, Canada**
      While conventional developments are subject to a maximum of 36% royalty, unconventional projects enjoy a flat 5% royalty.

   b) **Lower tax rates in the UK**
      The new Onshore Oil & Gas Allowance[v] was specifically formulated to improve commercial viability of unconventional developments by reducing the effective tax rate from 62% to 30%.

   c) **Subsidies for shale gas & CBM in China**
      Shale gas and CBM production will be subsidized by the government: RMB 0.4/ cubic meter for shale gas and RMB 0.2 / cubic meter for CBM will be awarded to upstream gas players.

   Provide Commercial Terms for Multi-Year Development Programs

   Unconventional wells produce less and experience rapid decline curves compared to conventional wells. An offshore well in Angola, for example, will produce about 4,000 barrels of oil equivalent per day (BOE/D), whereas a top-tier shale gas well will produce roughly 800 BOE/D[vi]. As a result, to maintain a stable level of production, an unconventional development requires a greater number of wells that are drilled throughout the life of the field[vii]. This results in multi-year development programs. For conventional developments, there is a clear hand over from development phase to production phase. For unconventional developments, both these phases overlap.

Gas players face the issue of longer life of field so it takes longer to recoup investments. To address this:

a) **Longer contract length in Argentina**
   - Exploration Period: 4 years initial + 4 years extension for Unconventional vs. 3 years initial + 3 years extension for Conventional Onshore
   - Development & Production Period: 35 years for Unconventional vs. 25 years for Conventional Onshore

b) **Longer Time Horizon for Losses Carried Forward in the UK**
   The Ring Fence Expenditure Supplement (RFES) allows carry forward losses to be offset against taxable profits for up to 6 years. There is proposed legislation to extend the period for unconventional developments to 10 years, recognizing longer payback for these types of developments[viii].

Adjust For Larger-scale Operations

Unconventional resources are less concentrated than conventional deposits, causing unconventional developments to extend across much larger geographic areas compared to conventional developments. While onshore conventional fields might require less than one well per ten square kilometres, unconventional fields might need more than one well per square kilometre (km2). The Marcellus Shale in the United States covers more than 250 000 km2, which is about ten times larger than the Hugoton Natural Gas Area in Kansas – the largest conventional gas-producing zone in the US[ix]. While there has been no real-life example of this to date, it is proposed that land tax can be minimized in light of the larger land size that entails from unconventional developments.

Address Social and Environmental Concerns

For unconventional developments to take off successfully, the needs and requirements of respective stakeholders must be considered. Apart from oil & gas companies, the other group of stakeholders is the local community.

Unconventional developments generally impose a larger environmental footprint compared to their conventional equivalents. Unconventional developments involve an intensive industrial process with major implications to land use. In addition, hydraulic fracturing activities pose the risk of groundwater contamination.

The UK ensures the local community shares the value created from unconventional developments. Local communities will receive £100,000/ site where hydraulic fracturing activities exist and are entitled to 1% of future revenues, worth up to £ 10 million / site[x].

2. **Marginal fields**

Marginal fields are a critical part of future gas production but are uneconomic to develop due to their low reserve size. For oil, industry benchmarks consider fields less than 30 MMSTB in size as marginal. For gas, the equivalent refers to fields less than 500 BSCF in size. On a barrel of oil equivalent (boe) basis, this is equivalent to almost triple the volume of a marginal oil field. So marginal gas fields are not only difficult to develop due to their size. The problem is exacerbated because the energy density of a gas field is much less compared to oil.

Attracting Niche Players by Sharing Risk

Large oil & gas companies are unlikely to invest in marginal field development. To encourage development of marginal discoveries and increase overall recovery of national hydrocarbon resources, policymakers must incentivize smaller companies to invest. Policymakers can target niche players who are too small to compete with their larger counterparts on high-CAPEX, technologically complex projects.

Malaysia has introduced Risk Service Contracts (RSCs), where costs of exploration and development are shared with the government. The Berantai RSC was the first contract of its kind in Malaysia. The Berantai field is located in the Malay Basin, offshore Peninsular Malaysia. It was discovered in 1978 but remained undeveloped due to marginal economics. Under the terms of the RSC, PETRONAS as regulator, retains ownership of the field, while RSC partners are responsible for development and operation. This way, most of the risk is still borne by PETRONAS, incentivizing the small players, SapuraKencana Petroleum and Petrofac to participate in E&P.

Improve Financial Attractiveness

In addition, PETRONAS sought the government's endorsement of tax incentives to be incorporated in the Petroleum Income Tax Act (PITA) to incentivize development of this type resource:

- Reduced tax rate from 38 percent to 25 percent for marginal field development to improve commerciality of the developments.
- Accelerated Capital Allowance to 5 years from 10 years for marginal field development where full utilization of capital cost deducted could improve project viability.

As a result of these initiatives, natural gas production from the Berantai Field was successfully brought on stream on 20 October 2012. The gas is currently being exported at a rate of 50 mmscfd from the field's first three wells and is expected to achieve 80 mmscfd this year.

3- Anticipating Future Challenges

We end our study with an unusual but important challenge. What happens when a gas field spans different contract areas? While conventional unitization methods apply, the situation can be further complicated if the gas field cuts across 2 or more different countries.

Looking ahead, development of some of the largest remaining gas-prone areas in the world are likely (if not already) to be affected by disputed border issues. Successful resolution of these areas will shift global gas dynamics significantly. This includes:

a) The Levantine Basin that extends across the territories of Lebanon, Israel, Palestine and Cyprus. This area holds probable undiscovered natural gas resources of 122 Tcf.
b) The Arctic Circle that encompasses 5 countries: Greenland, Canada, the US, Russia & Norway. This areas is estimated to hold 412 Bboe of in-place volumes, 67% of which is gas.

Achieving resolution is likely to be more difficult when gas is the primary resource. This is due to the absence of a global pricing standard, the complex inter-relationships between the production and marketing elements in the gas value chain, and the strategic need to provide security of domestic energy supply.

Development of the supply fields in this instance requires the simultaneous development of gas markets and infrastructure in both countries. The often nascent development of gas markets in one or both countries can provide quite perceptions of value, which can affect expectations of overall revenue sharing.

While there are several examples, we study the example of the Malaysia Thailand Joint Development Area (MTJDA). Despite taking 30 years of negotiation and discussion, the MTJDA is proof that the complex issues of sovereignty, political, economic and cultural differences can be overcome. The production-sharing model successfully reconciled 2 different fiscal systems: the Production Sharing Contract (PSC) in Malaysia and the Concession in Thailand. Of course, this could not have materialized without the political will amongst country leaders to resolve various sovereignty and political issues.

Conclusions

For gas developments to take off, an enabling environment must exist: contract features, commercial terms & price must be conducive for gas. Challenging gas projects may require additional special treatment, as seen in the examples for marginal or unconventional gas. Over and above all this, government intervention may be necessary to resolve delicate situations, as demonstrated in the final example. All enablers must be aligned -governments, regulators & upstream producers working in tandem to ensure success.

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