Manual for the
Open Upstream Gas and LNG Model

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1. Introduction and purpose of the model

a. Purpose of a model

A financial/fiscal model provides forecasted returns of a project to the investor and government. These estimates are based on fiscal, market, technical and corporate input variables, many of which are forward looking assumptions. Investors use financial models to determine whether to go ahead with a particular investment. Governments use models to compare their fiscal regimes with their peer countries and to assess how much revenue will flow into the state coffers from a particular project. A model is fundamental to help answer the following questions:

- What is the "fairness" of the current and potential deals?
- What is the equitability of the fiscal regime for investors and the government?
- What is the trade-off between "quick money" through front-loaded payments such as a signature bonus as compared to charging back-loaded payments such as a higher profit tax?
- What is the efficiency of tax incentives?
- What impact do tax regime changes have on the financial flows to both parties?
- How does the fiscal regime compare with others?
- How do changes in the ownership and commercial structure affect the financial flows to both parties?
- What are expected revenue flows from extractive industry projects and what long-term public investment policies can be funded and planned?
- How do revenue flows alter if market factors (for example, changes in prices or costs) or technical factors change?

To support project negotiations, it is crucial for governments to use fiscal models to assess the impact of the negotiated fiscal terms on the returns to the investor and the revenues to the government. Ideally the company and government share their respective models to ensure fiscal negotiations are undertaken on a common understanding. It may be, for example, that the parties use different assumptions regarding future prices, costs, new discoveries or feedstock sources to a plant, etc; which may lead to an impasse in negotiations given that the government revenues and investor returns are highly affected by these assumptions. By agreeing on the underlying assumptions and ways of calculating the financial flows, both parties can negotiate on the same basis.

We note however that in agreeing on assumptions, the government should recognize that the companies usually have more experience and information. So a comprehensive description and discussion of the assumptions is a vital step to assure a balanced understanding and identification of risks to the government.

Given that civil society groups normally do not have access to fiscal models, the use of an independent 'open' model such as this one may be the only alternative for assessing project returns and government revenues. They key challenge becomes gaining access to the main assumptions that are necessary in order to perform such a modeling exercise.

b. Purpose of this upstream and LNG model

This model has been developed for training purposes. It models the gas value chain from the upstream project to the use of gas under the form of LPG, LNG or as feedstock for local industrial or power generation uses. It allows users to assess different LNG structures that can be considered when producing LNG: the Tolling Structure, the Independent Plant Owner/Buyer Model, the Related Party Plant Owner/Buyer Model and the One Ring Fence model (see section 2 for an explanation of each structure). It provides various fiscal regime options for the upstream and mid-stream sectors to understand the impacts of changes on the government take and the private sector returns. It also allows for users to add upstream fields to the LNG project and understand what impact this has on the LNG economics when the processing facilities are shared. Furthermore, there is an option to test the impact of a National Oil Company (NOC)'s equity (on a paid equity or carry interest basis); and the impacts from granting fiscal incentives to finance the project can be assessed.

Different actors tend to use financial/fiscal models for different purposes – some of which can also be served by this model:

Upstream Investors – Usually international oil companies and national oil companies are investing in developing the upstream gas discoveries. They use models to assess if they will achieve an adequate return on their investments relative to the expected range of geologic, operational, and political and market risks that they take on. If they are required to "Carry" state oil company investments, they also want to assess the likelihood that those carries can be repaid under a variety of scenarios.

Investors in the LNG Plant – Usually these are international oil companies and national oil companies and often may include international gas buyers, construction companies or local utility companies. They are interested in assessing the economic viability of their investments under a range of operational and market risks and evaluating the reliability of gas supply.

Governments and National oil companies – Want to ensure the projects are economically viable and continue to attract investors, but at the same time achieve the maximum revenues for the country given that their natural resources are finite and are depleted over time.

For planning and budgeting purposes, governments also need to forecast how much revenue can be expected from the project/sector, the timing of those receipts and the potential volatility over the life of the project. This is particularly important for countries where the national budget is highly reliant on revenues from the sector or a particular project.

National oil companies may need to evaluate whether their share of the project investment has sufficient returns to be financed by lenders.

Financial sector – Private banks and multi-lateral agencies lending to the project investors utilize project economics to assess the underlying ability of the borrowers to repay their project loans and quantify the risk factors that could cause delays or defaults in payment.

Financial institutions making general purpose loans to the country or to local businesses will be interested in knowing how much additional revenues the government will be collecting, which may assist in repaying loans.

Credit rating agencies use economic models to forecast sources of government and country wealth to assist in their assessments and developing their ratings.

Civil Society – Want to know that the deal between the government and the private investors is reasonable and that it achieves the maximum returns for the country while still encouraging new investment. The model also serves as a means of independently evaluating what should be coming into the government treasury when and comparing that to actual reported revenues.

Gas Buyers – International LNG buyers or local utility companies want to assess the basic viability and reliability of the projects and whether they can continue to operate and supply them with gas under a variety of future market conditions.

2. Explanation of the different structures

a. Natural Gas compared to Crude Oil Projects

Natural gas projects are different than oil projects, because of the following factors:

- Natural gas cannot be easily stored and costs of transportation (pipeline and tankers) and treating (separation of liquids and liquefaction and regasification) are much higher than for oil. Each segment of transportation and treating of natural gas entails very different costs, technologies and risks compared to the upstream extraction.
- Greater economies of scale are often required for LNG plants to be economically and operationally viable; consequently the gas to be supplied to an LNG plant often comes from several blocks, each with different investors.
- Markets for gas are smaller and more segmented than for oil.

b. Gas Project Segments, Ownership Structures, Risks and Finances

Because of the above variations in risks and technical processes various segments of gas projects often take a different legal and ownership form. Activities and investments in the natural gas "value chain" are often split between different entities or groups of investors and not undertaken by the same group of investors. Commercial interests, tax and fiscal treatment may vary by segment.

Upstream – The ownership and legal structure is usually determined by the government that decides which parties are awarded the rights to explore and exploit the oil and gas reserves in a particular block. Usually this is a group of companies comprising an unincorporated joint venture (JV), oftentimes including the national oil company. There may be more than one block that produces gas in a region and each of those blocks will have a different set of owners/investors. Due to the high risks of not finding exploration success or reserves being uneconomic, **successful** upstream projects often earn higher rates of returns than the other segments of the value chain, e.g. 15% or higher.

***Gas Gathering Pipeline(*s)** – The gas produced in the upstream sector must be transported to shore to be processed. If only one block uses this pipeline, often the upstream block partners may also build and own the gas pipeline either through the same JV or via a different company that they form. If more than one block uses the gas pipeline, then there may be a separate company with the same or different ownership that charges a tariff to the upstream producers to use it (see line 96 in the 'Assumptions & Results' sheet in the model). Unless it is part of the upstream JV, the gas pipeline does not take ownership of the natural gas – it is considered to be a shipper only. It is common to have most of the upstream partners also be partners in the gas pipeline. But it is important to note that this pipeline is a strategic asset and has the potential to be monopolized because any one set of owners may decide to restrict its use or charge very high tariffs to any new blocks that want to use it. Consequently, many countries regulate these pipelines or take ownership[1] through the government to ensure that its capacity remains open and reasonably priced to any new producers. Since pipelines have relatively low technical and commercial risk, they often earn only medium level of return – typically in the range of 8-12%.

LPG Extraction – Depending on the "richness" (carbon content) of the natural gas produced, it may be more economic to extract and separately sell the liquids from the natural gas stream as Liquefied Petroleum Gas (Butane, Propane, etc.) prior to the liquefaction process. The investment to extract liquids from the gas stream can be made by the upstream group or may be made by the LNG plant owners. This model (Cell C14 in the 'Assumptions & Results' sheet) provides the option of selecting the LPG seller, or no LPG extraction at all if the gas stream is not considered to be "wet". LPG extraction revenues typically would only be received by the LNG plant owners if the plant owners took title to the gas stream, which is not the case in a normal Tolling scenario (see Table 2).

LNG Plant – These plants often require production from several blocks in order to be economic and entail very different technical and commercial risks than upstream investments. In addition there can be clear commercial conflicts of interest between upstream suppliers of gas and the LNG plant as the buyer of gas and reseller of LNG. Because of these factors it is most common that the LNG investors are a separate group than the upstream investors, although it is not uncommon to include some of the upstream investors in the LNG group as well. Typically the LNG plant commercial structure is one of four options:

1. ***Tolling Plant Model*** – The LNG plant investors pay the capital and operating costs of the plant, but the ownership of the produced gas remains with the upstream producers. The LNG plant owners charge a negotiated fee per unit of gas processed as their source of revenues (Line 99 of the 'Assumptions & Results' sheet in the model). After paying for the processing of gas into LNG, the upstream owners market and sell the gas into the export market.

[1] Angola is a case in point: As part of the overall deal the upstream blocks were required to pay all capital costs of the gas pipelines, and could include them in their PSA cost recovery. Upon completion of construction, the full ownership was transferred to Sonangol, the State owned company. All of the LNG partners were part of the management of the pipeline and

2. ***Independent Plant Owner/Buyer Model*** - Separate LNG plant owners are the buyers of the unprocessed gas. Under this structure, a separate group of LNG plant investors pays the capital and operating costs of the LNG plant, and those LNG investors purchase and take title of the gas on an arms-length basis from the upstream owners as it enters the plant "gate" from the gas pipeline. The LNG investors then sell the LNG into the export market.

3. ***Related Party Plant Owner/Buyer Model*** - Upstream investors own and operate the LNG plant. This is similar to the model option above, but the ownership of the LNG plant is the same as the upstream ownership group. Due to separate tax regimes that typically treat upstream activities differently than an LNG plant, there is usually a requirement to establish a transfer price (Line 4 of the 'Assumptions & Results' sheet in the model) from the upstream to the related parties in LNG plant. The Government would normally be the arbiter of what constitutes a fair transfer price for tax purposes.

4. **One Ring Fence Model –** Upstream investors own and operate the pipeline and LNG plant. There is no separate fiscal regime for these and all elements of the value chain fall under the upstream fiscal regime. Revenues and costs are consolidated along the value chain.

The model permits the assessment of the four structures. The Independent Plant Owner/Buyer Model and the Related Party Plant Owner/Buyer Model structures are both evaluated in the worksheets called "LNG Equity" and "Consolidated LNG Equity". *The difference between these two structures is that one would use an arms-length market price and the other an agreed transfer price.*[2] Even though the ownership structure may be different, the fiscal and economic result should be the same. Users of the model can assess the impact on investor returns and government revenues under different transfer price scenarios (see the sensitivity analysis section of the 'Assumptions & Results' sheet).

The Tolling plant structure is evaluated in the worksheets called "LNG Tolling" and "Consolidated LNG Tolling" sheets.

The One Ring Fence structure is evaluated in the worksheet called "Consolidated One Ring Fence."

There can be variations in all of these forms, so the substance of the structure must be scrutinized to ensure the right option is selected in the model, not to mention in reviewing the actual proposals given by the investor.

[2] For the purpose of the model, no distinction is made between a sale to an unrelated or a related party. There is only 1) the final export price of the LNG, and 2) the price that the LNG plant owners pay to the upstream owners to acquire the gas ("transfer price"). The methods for determining either of those prices can vary considerably (depending on such factors as the cost and scope and number of trains of the LNG plant, whether the gas is wet or dry, the distance and cost to transport the gas to the plant, and what market the LNG is being sold into). To derive the transfer price, a simplistic percentage formula is used, irrespective of whether the LNG owners were related to the upstream owners. It would always be up to the government to continually review or try to adjust any prices proposed between related parties during the life of the plant.

LNG Tankers – There are several options for ownership and control of the high cost specialized refrigerated LNG tankers. In many cases LNG buyers own or charter hire and manage these LNG tankers (Line 8 of the 'Assumptions & Results' sheet in the model); and the LNG is sold on an free on board (FOB) basis from the LNG plant (Line 7 of the 'Assumptions & Results' sheet in the model). In other cases the LNG sellers themselves may own or charter hire the LNG vessels; and in those cases the LNG may be sold on a Delivered ex-Ship (DES) basis price as determined at market at the regasification receiving terminal country (Line 9 of the 'Assumptions & Results' sheet in the model). There are often variations whereby the LNG owners may own or charter hire some vessels and sell those cargoes on a DES basis, but will sell the remainder of the LNG to buyers on a FOB basis under an arrangement where the buyers arrange and pay the costs of their own LNG vessels. The model allows users to either choose the FOB or DES method.[3] If the project uses a mix of both methods, the user must compute the average price and average tanker costs outside the model before inputting in any one year.

c. Fiscal[4] Arrangements by Segment

- The upstream sector fiscal terms are determined by the Production Sharing Agreement (PSA) or legislation. These documents can be used to input the fiscal terms into the model.
- The gas pipeline costs usually are either considered part of the upstream costs for fiscal purposes, or if a separate entity, would typically be part of the country's corporate income tax regime.
- The LNG plant is usually part of the country's corporate income tax regime, but in many cases the plant owners negotiate fiscal terms that could include features such as:
    - Permitting some capital costs from LNG to be taken as deductions against the upstream fiscal regime. Typically, this would only be possible in situations where the LNG equity investors are the same as the upstream investors (in the One Ring Fence model all the capital costs would be allowed as deductions).
    - A specified period of tax holidays or tax exemptions
    - Special levy imposed if gas prices rise above a certain level and the LNG plant investors are the sellers of the LNG.
    - When the LNG plant is owned by the same group of investors as the upstream and the fiscal regime is not integrated (i.e not in the case of the One Ring Fence model), there is usually an "arms-length" type of transfer price required for the gas in order to determine the tax treatment and split between the upstream and downstream fiscal regime.

Tables 1, 2, 3 below, summarize the above explanations.

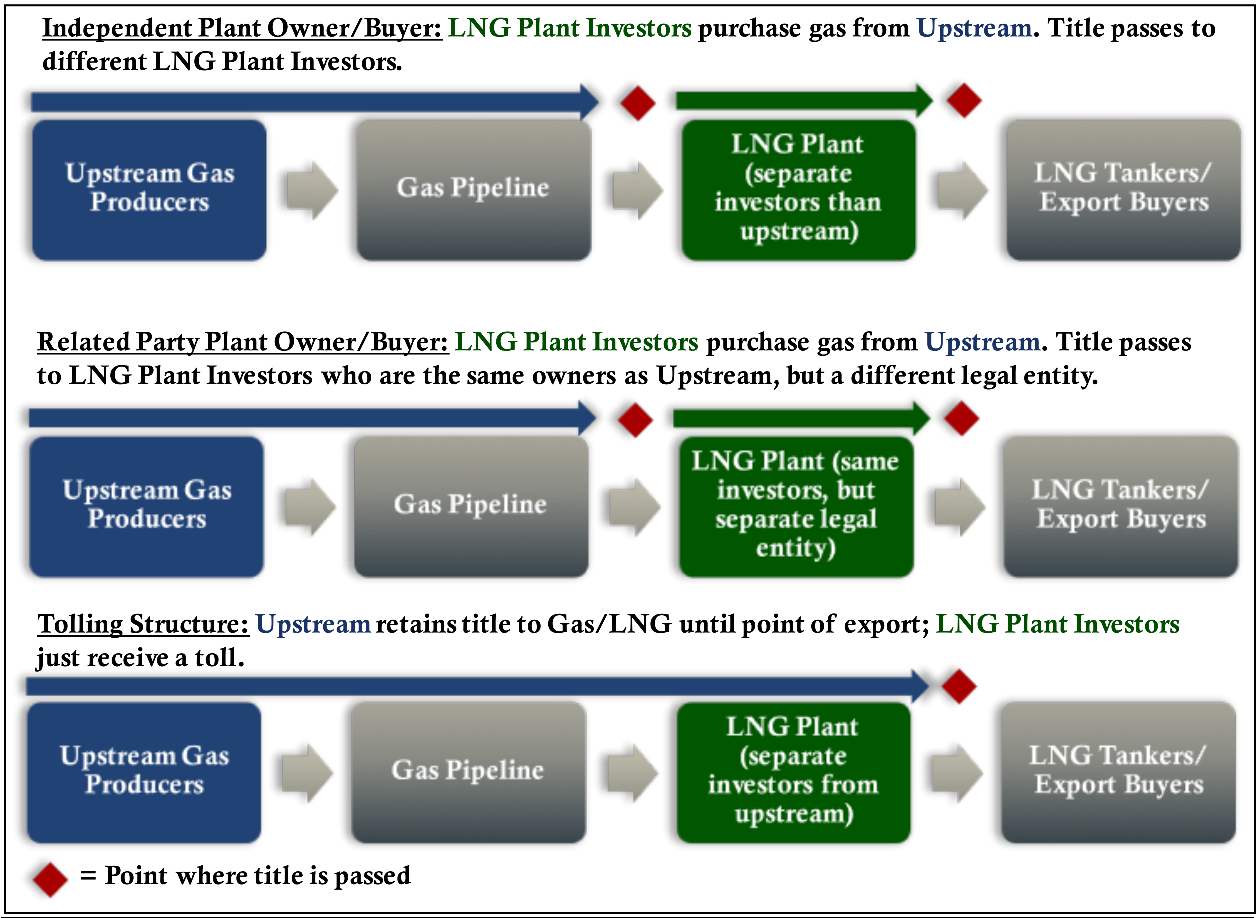
[3] The model only provides the DES option for the LNG equity case where the LNG plant owners purchase the gas from the upstream sector. This is because the upstream gas owners are unlikely to manage tanker charters and marine logistics; and they are unlikely to want to risk complicated tax authority reviews related to upstream transfer prices that would need to be calculated if they sold on a DES basis.

[4] Note that the model allows to use two types of profit sharing arrangements – R-Factor based and production-based

Table 1: General characteristics of the different segments of an LNG project

Gas Projects - Aspects by Segment	Upstream	Gas Pipeline	LNG Plant
Ownership	Granted by license award by government	Can be part of upstream, or different	Can be part of upstream, or different
Participation by NOC	Commonly the case	Varies	Varies
Legal Form	Typically unincorporated JV	Part of upstream JV, or Investors purchases shares in a separate company	Shares company (Investors that can be the same as in the upstream purchase shares in a separate LNG company)
Source of Revenues	Sales of natural gas to LNG plant, or sales of LNG to export buyers	Tariffs from upstream, or part of upstream Costs	Tolls from upstream, or sale of LNG to export buyers
Main Risks	Geologic, market (gas prices) successful exploration, completion, and operational	Completion, and operational only (maintaining full capacity)	Completion, operational (maintaining full capacity), and market (gas prices) (if not a Tolling plant)
Fiscal Regime	PSA, or upstream royalty/petroleum tax regime	Part of upstream fiscal regime, or corporate tax	Corporate tax, often with special incentives or taxes
Rates of Return (typical range)	15% +	7-13%	11-16%

Table 2: Overview of where the title to gas and LNG passes under the different ownership structures



In the case of the One Ring Fence model, the interpretation of the passage of the title is similar as with the Tolling structure (i.e. the title is passed at the point of export after the LNG plant). However, while in theory, all the activities from exploration through LNG are carried out by one single company that files one tax return, in practice there will likely be separate companies set up for each component of the value chain (i.e. upstream company, pipeline company and an LNG company). This is oftentimes due to national tax systems (such as that of the United States), which require a formal splitting of foreign income between extractive and non-extractive businesses. Then there would either be a consolidation into a single parent company that files the tax return, or simply some sort of allocation of costs and revenues between the entities depending on the tax set-up to achieve the same net effect of a single ring fence tax return. In such case the gas title transfer may actually take place between the related companies in the country.

Table 3: Overview of which segment is bearing the risk factor according to the commercial structure

Risk Factor:	Tolling Structure	Equity Structure – LNG Plant owners are same as upstream	Equity Structure – LNG Plant owners are separate
LNG market price risks	Upstream bears full risk	LNG plant investors bear full risk	LNG plant investors bear full risk unless transfer price from upstream is linked to market price
Gas transfer price to plant	Not applicable since gas is not sold to plant	Upstream owners want as low as possible	Upstream owners want as high as possible and plant owners as low possible – which will get the parties to a true arm's length price
Upstream production and reserves risks	Both upstream and LNG investors bear risk unless there is a send-or-pay clause to protect plant investors	Both upstream and LNG investors bear risk, but could entail a shift due to different fiscal regimes.	Both upstream and LNG investors bear risk unless there is a send-or-pay clause to protect plant investors
LNG plant operability and downtime risks	Both upstream and LNG investors bear risk unless there is a take-or-pay clause to protect upstream investors	Both upstream and LNG investors bear risk	Both upstream and LNG investors bear risk unless there is a take-or-pay clause to protect upstream investors
LNG plant capital cost risks	LNG plant investors take full risk, unless tolling tariff formula is linked to costs	LNG plant investors bear full risk	LNG plant investors bear full risk
LNG evaporation product loss	Upstream bears full cost	LNG plant investors bear full cost	LNG plant investors bear full cost
Upstream capital cost risks	Upstream bears full risk	Upstream bears full risk	Upstream bears full risk

In a One Ring Fence model, all the companies (or the single company) would share these risks and the allocation of the risk would not be relevant since all the investors and their equity shares would be the same and the cost or benefit of the risk would have the same tax impact irrespective.

3. Using the model

a. Structure

The model is composed of 21 worksheets, which are linked by formulas. Table 4 provides an overview of the function of each worksheet. The worksheets are color coded, with the blue worksheet ('Assumptions & Results' sheet) being the place where users can input all variables and can observe the compiled results. This is also where the sensitivity analysis is presented. Users will spend most of the time in this worksheet. The red worksheets provide the user with the upstream project economics and government revenues for 3 fields. The green worksheet provides the user with the pipeline project economics and government revenues. The orange worksheets provide the user with the LNG project economics and government revenues under the four structures explained in section 2b. The black worksheets consolidate the upstream, pipeline and LNG project economics under the four structures. The grey sheets show the calculations for the One Ring Fence model. The yellow sheet calculates the impact of debt financing on government payments, and the purple sheet the returns to the national oil company (NOC) and international oil companies (IOCs).

Table 4: Worksheets of the model

Name of worksheet	Description of variables in worksheet
Assumptions & Results	Assumptions are inputted and key results are presented graphically
Field 1 Depr	Depreciation schedule of the capital expenditure of Field 1
Field 1 Fiscal	Computation of the fiscal terms paid by upstream gas investors of Field 1
Field 1 Investor	Calculation of the financial return of the investor and of the government take for Field 1
Field 2 Depr	Depreciation schedule of the capital expenditure of Field 2
Field 2 Fiscal	Computation of the fiscal terms paid upstream gas investor of Field 2
Field 2 Investor	Calculation of the financial return of the investor and of the government take for Field 2
Field 3 Depr	Depreciation schedule of the capital expenditure of Field 3
Field 3 Fiscal	Computation of the fiscal terms paid by upstream gas investor in Field 3
Field 3 Investor	Calculation of the financial return of the investor and of the government take for Field 3
Gas PL	Economics, financial returns and government take of the gas pipeline
LNG Equity	Computation of LNG project economics of Equity/buyer structure, whereby LNG owners take title to gas from upstream and sell to 3rd parties

	(irrespective of whether the LNG plant owners are the upstream operators)
LNG Tolling	Computation of LNG project economics of Tolling structure, whereby the LNG plant does not take title to gas and the gas owners pay a toll (i.e: a fee) for processing purposes
Consolidated LNG Equity	Consolidation of the economics of all 3 elements of the projects (upstream, pipeline and LNG facility) under the LNG Equity model
Consolidated LNG Tolling	Consolidation of the economics of all 3 elements of the projects (upstream, pipeline and LNG facility) under the LNG-Tolling structure
One Ring Fence Depr	Depreciation schedule for the consolidated model
One Ring Fence Fiscal	Fiscal computations for the consolidated model
Consolidated One Ring Fence	Consolidation of the economics of all 3 elements of the projects (upstream, pipeline and LNG facility) under the consolidated – One Ring Fence model
Financing for Fiscal Terms only	Computation of the debt schedule to calculate the financial incentive resulting from leveraging the project
NOC and IOC shares plus carry	Computation of the National Oil Company (NOC's) and International Oil Company (IOC's) shares when the NOC has an equity

The cells in the model are also color coded to facilitate the navigation of the model. Table 5 explains each color coded cell used in the model.

Table 5: Color-coding of cells in the model

Color	**Description of color coding**
Light blue	Input variables that can be changed by the user. Price, production, cost and fiscal inputs should all be edited in the 'Assumptions and Results' worksheet. The structure to be analyzed can be chosen in cell C172 of that tab.
Light green	Section dividers
Yellow	Checks that allow the user to see whether errors have occurred in the model. This color has also been used to highlight which model structure is activated and therefore which results are valid and invalid
Red	Key results
White	Fields that are linked by a formula in the model and should not be changed by inexperienced modelers, as changing them may result in the model not functioning properly
Red font	Explanatory notes within the model

It is important to note that the user needs to pick the commercial structure that he/she wants to analyze in Cell C172 in the 'Assumptions and Results' worksheet. If the user wants to assess the

Tolling structure, then "1" should be inserted. If the user wants to assess the Equity structures, "2" should be inserted (in case the LNG plant owners are the same as the upstream owners, governments should be involved in approving the transfer price to avoid the company shifting profits into the less onerous tax regime). If the user wants to assess the One Ring Fence structure whereby all segments are consolidated under one tax regime, "3" should be inserted.

b. Calculations and Outputs

Understanding how the model is linked

As explained above, the white fields (the majority of the fields in the model) are linked by formulas and should only be edited by more experienced modelers, given that changing the formulas might break the model and lead to wrong results. To understand how a particular field is linked within the model, the "trace precedents" and "trace dependents" functions in Excel can be used. These will provide insights into what cells are calculating the field and what other cells are affected by the field.

Checking for errors

As explained above, the yellow background cells provide the user with feedback on whether there are mistakes in the model and which results are valid and invalid based on the structure that has been chosen. This should help the user to make sure that the correct worksheets are used for the structure that is being analyzed. For example, if the user selects the Tolling structure in the assumptions page, then only the 'LNG Tolling' and the 'LNG Tolling Consolidation' worksheets are VALID and the 'LNG Equity' and 'LNG Equity Consolidation' worksheets INVALID. This will be flagged in the top left corner of these four worksheets. There are several other cross-checks in the model. If the word INVALID appears in any spreadsheet the user should check for structure chosen in cell C172 and/or any errors in the input data or formulas.

Checking and understanding the results

- **Checking that project and investor returns are reasonable** – Users should check the net present value (NPV) and internal rate of return (IRR) for each of the segment of the project.[5] Both the NPV and IRR indicators take into account the time-value of money. A higher discount rate used for the NPV calculation means that later cash flows are discounted at a higher rate (i.e. that later cash flows are worth less). The IRR is the discount rate at which NPV=0. Table 1 of this guide provides a rough reference as to what range of returns (IRR) are required for each segment (these rates are only ballpark figures and need to be risk adjusted). All of the segments need to be commercially viable in order for the whole project to go ahead and attract investors. If the results show that the individual segments are earning much lower or much higher rates of return, it may be a sign that the assumptions need to be reviewed, that the project is not economic and/or that the fiscal system is too onerous. If the rates of return are

[5] Cells C39 and C40 of the 'investor' worksheets for field 1,2,3; cells C39 and C40 of the 'Gas PL' worksheet; cells C49 and C50 of the 'LNG equity' worksheet, cells C39 and C40 of the 'LNG Tolling' worksheet; cells C31 and C32 of the 'Consolidated LNG equity' worksheet'; cells C29 and C30 of the 'Consolidated Tolling' worksheet; and cells C29 and C30 of the 'Consolidated One Ring Fence' worksheet.

high, the commercial terms may be unduly skewed to the investors with the government being able to increase taxes and still attracting investors.

- **Checking that the Government Take (GT) is reasonable** - Another factor to look at is the GT, which is defined as all payments going to the government (royalties, Government's share of production under a PSA, income taxes, etc) divided by the pre-tax project cash flows. Given the higher returns on the upstream segment, GT tends to be higher there than for the pipeline and LNG segment. Apart from reviewing the GT for the individual projects, the consolidated GT should also be reviewed to assess whether subsidies, incentives or fiscal reliefs granted in one or more segments (necessary to reach the NPV and IRR to make those segments attractive for investors) are worth it on a consolidated basis.

- **Checking the interpretation of the fiscal terms, assessing the impacts of different structures and potential for profit shifting** - When deciding on the commercial and legal ownership structure for the project it is important to understand how the fiscal terms are interpreted, as different interpretations may have a large impact on the revenue flows. For instance, when considering a Tolling structure the upstream investors may find that treating the tolling costs as simple operating cost subject to cost recovery may create a disadvantage by displacing or deferring recovery of costs from the other upstream operations and capital spending. When compared to other commercial or legal structures, such as the One Ring Fence option or Equity option of selling the gas to the LNG plant, the investor economics are negatively affected. In this type of case, the upstream operators may seek an interpretation of the PSA that would allow them equivalency with the other ownership options. In this example, a means of achieving that parity would be to "netback" the final LNG FOB price by netting out the tolling costs.[6] These interpretations can be very technical and not easy to follow, but can be critical to the financial returns to investors and to the Government.

  Another interpretation example comes from countries where the government allows the investors to interpret the PSA in such a way to permit some of the LNG capital costs to be considered "upstream" in nature and thereby become part of PSA Cost Recovery. Since effective Government Take is generally higher in the upstream, this has the impact of improving the investor's rate of return by reducing profit gas and taxes. This can be a legitimate means of incentivizing LNG investment, but must be recognized as being, in effect, a subsidy by the government. This latter type of interpretation would normally *not* be considered unless the project structure was the Related Party Plant Owner/Buyer Model where the upstream investors were the same as the LNG plan investors. The model provides options to allow for the pipeline and LNG expenditures to be deducted from the upstream project.[7] In the One Ring Fence structure, this situation is taken to the extreme since all capital costs and revenues across the value chain are consolidated under the upstream fiscal regime.

[6] This is what this model does in Lines 6-7 of the 'Field 1, 2 & 3 Fiscal' sheets.
[7] The model gives this possibility in lines 62-65 and 76-83 of the 'Assumptions & Results' sheet.

Furthermore, the model also allows for the transfer price from the upstream to the LNG project to be adjusted. If the transfer price is reduced, the upstream project will appear less economic, while the LNG project appears more economic. This impact should be viewed with caution as a reduction of the transfer price will also result in a fall in overall government revenues given that the LNG segment is taxed at a lower rate than the upstream segment. If upstream owners also own the LNG plant they will have a natural benefit and incentive to shift revenues to a lower tax regime, which means less for the government.

- **Understanding the timing of government revenues**. As noted above, early returns to the investor will increase the IRR and NPV of the project. Given the high levels of capital expenditure required for oil and gas projects, it is common for countries to allow for cost recovery and depreciation in the fiscal terms. This will result in government revenue flows being delayed. The consolidated worksheets provide the government and civil society with an indication of when revenues from the various segments should be expected, which may help governments in fiscal planning and manage expectations of civil society.

- **Checking the competitiveness of the fiscal terms.** In order to test the competitiveness of the fiscal terms, it may be worthwhile running a "benchmarking" evaluation of similar projects in the same country or in another country (See sources of data and assumptions section of where data for similar projects may be found).

- **Checking the impact of financing incentives:** Borrowing and financing can have an impact on the investors' returns if fiscal incentives allow for interest deductions or cost recovery. The model does provide the option for evaluating the impact of such incentive on investor returns.[8] But since investors will borrow or pay returns to shareholder capital irrespective of the tax treatment of interest, it would be an analytical mistake to focus on leveraged economics. So it is recommended that financing effects are not considered to assess the basic viability of projects. Financing is of course a huge issue in mega-projects such as LNG, especially if the government has a paid up equity share or for smaller independent companies; but it must be clearly segregated as a separate type of analysis. If interest costs on loans from affiliated parties are permitted as tax deductions, great care must be taken to ensure they are not excessive.[9]

- **Checking the impact of leasing a floating LNG plant (if there is one) rather than building it:** In lines 85-87 of the Assumptions sheet, the model provides the option to

[8] See line 128 of the 'Assumptions & Results' sheet.

[9] See for example: http://www.afr.com/business/energy/gas/chevron-claimed-gorgon-bonanza-would-pay-for-tax-for-cuts-for-everyone-20151116-gl0jo1

assess the implications of a leased floating LNG plant.[10] Leasing an LNG plant would diminish the capital expenditure available for depreciation. However, the annual leasing fees are generally tax deductible.[11] Often the investor's tax position improves as a result of offsetting the taxable income with annual leasing fees over the years rather than with capital expenditure depreciation (which would be the case if the investor owns the LNG plant). Investors may also argue that leasing is cheaper and faster than building an LNG facility. For the national oil company this may also prove beneficial, as it will not have to mobilize such large up-front expenditures if it has a paid up equity. The downside of such arrangement for the government may include 1) loss of taxes, 2) it is difficult and expensive to add capacity at a later date if there are new discoveries, 3) it involves less local content, and 4) offshore facilities are harder to inspect and audit.

- **Checking the investment requirements and returns to the National Oil Company:** The model allows the user to test the impacts of varying government equity shares and the capital costs that would have to be financed (either by the government or from lenders). The model assumes the same equity percentage share throughout all phases of the value chain (upstream, gas pipeline, and LNG Plant). There is an option for the IOC's to carry the NOC's share of upstream capital costs, which is an option typically established under the terms of Production Sharing Agreements. The model assumes that any carry would be limited to upstream capital costs only, and additionally assumes repayment of the carry is limited to the NOC's share of Cost Recovery gas. The interest on this carry will alter the return to both the IOCs and the NOC. The terms of these carries must be carefully analyzed and modeled to determine their impact on the Government under a variety of assumptions and cost conditions. Leveraged financing is not typically considered in the model as explained above, but an NOC carry can be an exception in that it is a requirement under the PSA that affects entitlement to gas, and the carry repayment risks assumed by the IOCs are to be factored in in a project decision.

- **Understanding the sensitivity analysis.** It is important to test the resilience of the results under a range of circumstances. This exercise is called "sensitivity analysis". While the results for the investors and for the government may look reasonable in the base case, it is important to ensure that these results hold under modified assumptions. For example, it should be tested that the investor IRR and NPV indicators do not collapse when gas prices fall slightly and that government take falls with a rising gas prices. If either is the case, there will likely be pressures for the contract to be

[10] The interest rate for the FLNG lease is assumed to be 8%

[11] The model assumes that if there was a deductible capital lease allowed there would be no deductions allowed for financing costs inasmuch as the lease itself is a form of financing and the lease costs themselves would be deductible. There may be circumstances where a tax authority might allow interest on the non-leased portion of the LNG investment or some other combination, but the model couldn't anticipate this complexity.

renegotiated when commodity prices change. This model provides for sensitivity analyses from line 225 in the ‘Assumptions and Results’ worksheet. Apart from price changes, the sensitivity analysis tests the impacts of varying assumptions regarding the production, capital expenditure, tolling fees and delay in production start.

- The sensitivity analyses are calculated using the ‘data table’ function in Excel, which cannot be traced by the ‘trace precedents’ function. If a particular result in the sensitivity analysis is surprising and the user is unfamiliar with the ‘data table’ function, it is recommended to re-run the model with the revised assumptions to better understand the results.
- To test the sensitivity of lower production volumes and production start delays, the model includes additional input variables for the upstream gas field 1, which have not been replicated for fields 2 and 3. This is for illustrative purposes. The same sensitivities should be performed for these two other fields once more information is available.
- We included the same sensitivity percentages for all factors to help identify which factor has the biggest impact. Users can adapt these percentages to his/her needs.

4. Assumptions and input variables

Input assumptions have a significant impact on the modeled results. If the input assumptions are wrong, the results will also be wrong. Therefore a careful review needs to be undertaken of the available information. The most significant input assumptions and data are as follows:

Forecast prices – LNG prices typically are agreed with individual buyers under a contract formula. These formulae can vary, but typical methods include:

- Directly linked to a published natural gas index price at a large natural gas market, e.g. Henry Hub (see further explanation below).
- Directly linked to a published crude oil index price for a widely traded crude type, e.g. Brent. This type of price would also require an adjustment to recognize the different energy content, processing requirements and standard of measurement of oil versus natural gas.
- An agreed blended mix of the above two basic methods.

These prices are usually on a DES basis (at the market) and may be further adjusted to an FOB basis to recognize transportation costs to reach such reference markets, energy or BTU content of the gas, and whether the contract is short or longer term in nature.

Generally LNG and natural gas that is produced and sold from any country is priced based on international markets. Those markets are divided into three regional markets: 1) North America, where the pricing point is called "Henry Hub" and is the primary price for natural gas futures contracts traded on the New York Mercantile Exchange and the over-the-counter (OTC) swaps traded on the Intercontinental Exchange (ICE); 2) Asia where the pricing benchmark is called Japan Customs –cleared Crude (JCC), which is the average price of crude of the second largest Asian importer and is a commonly used index in long term LNG contracts in Japan, Korea and Taiwan; and 3) Europe where the trading point is called the National Balancing Point, which is the virtual trading location for the sale and purchase and exchange of UK natural gas and is the pricing and delivery point for the ICE Futures Europe natural gas contract.

LNG pricing references and benchmarks are still evolving.For instance, the crude-price linked methodology was widely used in older long term LNG contracts and still influences how LNG is priced. Newer sales contracts are more frequently referencing natural gas or LNG price hub indices as benchmarks.

Markets are affected by general growth in energy consuming economies and its effect on demand for energy, ease of substitution of one type of fuel for another, and competing LNG projects in other parts of the world. Often it may be best to use as a base case a generally recognized forecast of prices, such as those from the World Bank (see http://www.worldbank.org/en/research/commodity-markets). All that we know about any price forecast is that it will be wrong, so testing a range of sensitivity cases for prices is essential to better understand the risks and upsides and how they may affect the key results.

Production forecasts – Not only are upstream production rates and reserves needed to run the model, it is also important to note that for natural gas projects there is always a certain amount of "product loss" as the natural gas may be used as a fuel in running machinery or equipment, plus in the process of being cooled to a liquid form or being warmed back into a gaseous form and stored usually entails a certain amount of evaporation. Keep in mind that full upstream production capacity will always constrained by the LNG plant designed capacity to take the gas and by any LNG plant downtime for maintenance or emergency shut-ins. Consequently, upstream production forecasts must take this into account. The model includes input for these factors.[12]

With respect to product loss due to evaporation or running machinery, in the Tolling model the upstream gas owners bear the impact of any product loss or evaporation during the LNG plant processing as they would still pay the toll based on product going into the plant and still retain ownership of the gas.[13] In the Equity model the LNG plant owners bear the economic impact of the product loss since they took title to the gas at the LNG plant gate[14] (see Table 3).

Domestic supply of gas – Since natural gas and LPG can be used relatively cheaply and easily domestically for electrical power generation or direct industrial or consumer purposes, most LNG projects contain some requirement for natural gas or LPG to be supplied to local markets. The negotiation of the volumes to be dedicated for this purpose, the determination of the sales price and the tax treatment can become critical issues to investors and the government. The challenge is that the amount actually utilized in the domestic market may build or vary annually as the gas markets are being developed whereas investors are locked-in in long-term gas contracts with gas buyers. The model permits a range of assumptions to be incorporated.[15]

Capital costs forecasts – Since capital costs occur in the very beginning of a project they have a much greater impact on discounted value indicators. In addition, cost overruns have a disproportionate impact on host governments due to the interplay of government take factors and the more restricted options for financing typically available to government. Also, several studies indicate that most companies tend to greatly underestimate the capital costs on megaprojects. These factors taken together mean that testing capital cost sensitivity analyses, especially testing for large overruns, are especially important for any host government or national oil company (the model allows this in the sensitivity analysis section of the 'Assumptions & Results' sheet). For more information on why such analysis is crucial, see:

http://www.spe.org/ogf/print/archives/2012/02/02_12_08_Feat_Cost_Est.pdf
http://www.costandvalue.org/download/?id=2047
http://www.ogdeestimating.com/services/field-development/type-of-estimate
http://www.ey.com/GL/en/Industries/Oil---Gas/EY-spotlight-on-oil-and-gas-megaprojects#.VhlIRexViko

[12] See 'Assumptions & Results' sheet, lines 24 and 25
[13] See 'Field 1,2 & 3 Investor' sheet, line 12
[14] See 'LNG Equity' sheet, line 13
[15] See 'Assumptions & Results' sheet, lines 10-11 and 26-28

Fiscal terms and taxes – As explained above, this information should be available from published petroleum and tax laws of the country, plus any agreements, such as Production Sharing Agreements,[16] between the government and the upstream investors. Oftentimes, the details of the LNG fiscal terms are not agreed until right before the Final Investment Decision is made.

Units of measurement – Extreme care must be taken when entering data into an economics model to ensure that the units of measure are known and are made consistent within the model, and that conversions are performed where necessary. The following industry convention should be taken into account:

1. Natural gas production, gas reserves and pipeline capacity are typically measured in units of volume, such as Thousands of Standard Cubic Feet (MCF) or Thousands of Cubic Meters (MCM). When referring to gas reserves it is common to use a measurement of Trillion of Cubic Feet (TCF).
2. LNG Plant capacity is commonly measured in units of weight, typically in Millions of Metric Tons (MT) since they are producing gas in a liquid form.
3. LNG Tanker capacity often is often stated in Cubic Metres (CM), a measurement of size.
4. Condensate (liquids present in wet gas fields) is commonly measured in Barrels, while LPG may be measured in Barrels or Metric Tons.
5. In many cases capacity is measured as an amount PER DAY while in other situations volumes are referred to as an amount PER ANNUM.
6. In some cases where there is a high liquids content in the natural gas stream the gas may be measured or referenced in units relating to its energy content, typically Thousands of British Thermal Units (MBTU) or in some cases as Gigajoule**s.**
7. Most natural gas and LNG sales prices are quoted and paid in U.S. Dollars. A commonly referenced unit in price quotes for natural gas is Dollars per MCF and may be converted to a price per MT for LNG.
8. Most tariffs or tolls are referenced in U.S. dollars. Pipeline tariffs are usually a price per MCF. LNG Tolling tariffs may be a price per MCF or in many cases a price per MT.
9. Also, attention must be paid to the “thousands” conventions. In the petroleum industry, “M” typically is used to refer to one-thousand and “MM” refers to one-million (or a thousand thousands). The economics model itself usually refers to input and output amounts expressed in millions, or MM.

The below tables can help users with conversions where necessary:

[16] See resourcecontracts.org for a database of publicly available contracts.

Table 6: General Conversion Factors for Energy

To:	TJ	Gcal	Mtoe	MBtu	GWh
From:	*multiply by:*				
TJ	1	238.8	2.388×10^{-5}	947.8	0.2778
Gcal	4.1868×10^{-3}	1	10^{-7}	3.968	1.163×10^{-3}
Mtoe	4.1868×10^{4}	10^{7}	1	3.968×10^{7}	11630
MBtu	1.0551×10^{-3}	0.252	2.52×10^{-8}	1	2.931×10^{-4}
GWh	3.6	860	8.6×10^{-5}	3412	1

Source: IEA

Table 7: Additional Useful Conversion Factors

1 SCM (Standard Cubic Meter)	**= 1 cubic metre @ 1 atmosphere pressure and 15.56 ° C**	
1 Cubic Metre	= 35.31 Cubic feet	
1 BCM(Billion Cubic Metre) / Year of gas (consumption or production)	= 2.74 MMSCMD	365 Days a Year
1 TCF (Trillion Cubic Feet) of Gas Reserve	= 3.88 MMSCMD	100% Recoverable for 20 years @ 365 days / Annum)
1 MMTPA of LNG	=3.60 MMSCMD	Mol.Weight of 18 @ 365 days/Annum)
1 MT of LNG	=1314 SCM	Mol.Weight of 18
Gross Calorific Value (GCV)	10000 Kcal/ SCM	
Net Calorific Value (NCV)	90% of GCV	
1 Million BTU (MMBTU)	= 25.2 SCM	@10000 Kcal/SCM; 1 MMBTU= 252,000 Kcal)
Specific Gravity of Gas	=0.62	Molecular Weight of Dry Air=28.964 gm/mole)
Density of Gas	=0.76 Kg/SCM	Mol.Weight of Gas 18 gm/mol
Gas required for 1 MW of Power generation	=4541 SCM per Day	Station Heat Rate (SHR); ~ 1720 Kcal/Kwh-NCV (50% Thermal Efficiency); N.Gas GCV-@10000 Kcal/SCM
Power Generation from 1 MMSCMD Gas	=220 MWH	Station Heat Rate (SHR); ~ 1720 Kcal/Kwh-NCV (50% Thermal Efficiency); N.Gas GCV-@10000 Kcal/SCM

Source: GAIL[17]

[17] http://www.gailonline.com/final_site/energyconversionmatrix.html

When using conversion tables to convert from gas volume measures (such as CF or CM) to gas energy measures (such as BTU or gigajoules) it must be recognized that the degree of liquid content in the gas stream can affect those conversion factors. In the same way when converting from liquid volume measures (such as barrels or MCF) to weight measures (such as metric tons) the specific gravity of the liquids will affect that conversion. These ranges are usually relatively small, but can create differences from the conversions used by a company or government in their models

5. Application of the model

For illustrative purposes, this section runs through a hypothetical case based on the inputs presented below.

a. Assumptions and references

Fiscal Terms

- The PSA is based on an R-Factor.
- A $1 Billion unrecovered exploration cost is included. It was assumed that some of that amount is not recoverable as they would be outside the ring fence.
- For the gas pipeline segment the standard corporate income tax of 32% with no tax relief or investment uplift.
- For the LNG segment the standard corporate income tax of 32% with no tax relief or investment uplift is used.
- Interest on debt is not deductible
- NOC has an equity share of 10% and is carried by the investor at an 8% interest rate.

Technical and Commercial Inputs

- The LNG production volumes are estimated based on four LNG trains at 6 million tonnes per annum each. This is equivalent to a total LNG plant output of approximately 1,062 million cubic feet per day (MMCFD). The upstream production is assumed to be 1650 MMCFD per field before taking account for LNG production losses of LNG plant downtime.
- It is assumed that two upstream projects are supplying the LNG plant. Figures for both fields are the same.
- The pipeline construction has been scheduled to conclude one year before start of operations to allow for line testing, inspections and potential modification prior operation.
- The model uses the Tolling structure as the base case.
- The capital cost and timing of expenditure figures are based on educated guesses and adapted to provide reasonable return rates for the different segments of the project.
- No LPG or Condensate production is assumed.
- 2% domestic gas sales are assumed.
- Under the LNG Tolling arrangement it is assumed that the gas price to be used under the PSA terms are to be interpreted as the FOB Export price less the LNG toll itself. This impacts the cost recovery cap. It may be argued that a "Wellhead" type of price for gas is really NET of the toll that would need to be incurred prior to be able to sell the gas (even though the wellhead concept is not used in the PSA per se). A commercial reason

is that companies may not be willing to agree to an interpretation of the PSA whereby paying a toll to a third party to process/liquefy the gas would put them in a worse situation than selling the gas directly to a plant owner at the same netback price strictly due to the mechanics of how the Cost Recovery cap functions.

b. Asking the right questions regarding the assumptions and interpreting the results

Fiscal Terms

When you based your model assumptions on a contract and the law, some questions that might be asked are:

- Will these terms continue for 30+ years even if costs and markets and production vary?
- Are there any other "interpretations" that end up being agreed (or not agreed) with the government that were not modeled that might create a different result?

Commercial Assumptions

- Is a constant FOB export price of $8.75 per MCF realistic in today's market, or what is anticipated for the life of the project? If price assumptions are changed, what impact might that have on costs, tariffs or other input assumptions?
- Is an assumed domestic gas price of $2.50 consistent with other terms and assumptions?
- Does a LNG toll of $4.50 reasonable and commercially viable to all parties? Will it change over time if world markets change or new projects come into the plant as feedstock?
- Does this LNG toll option yield significantly different results than utilizing an LNG Equity option? If so, what caused the difference and does that cause any concern?
- Does the project include a floating LNG facility, and if so, is it leased?

Technical Assumptions

The economics assume recoverable reserves of 34 TCF.

- Are there sufficient reserves already discovered in this area to provide this level of production to constantly feed into the LNG plan on an uninterruptable basis, that is, more than 34 TCF in reserves in order to cover unexpected shut-ins or some fields performing at less than expectations? Are the investors and the government relying too much on the hope that additional reserves will be discovered in the future?
- Are reserves so high that it indicates that it might be less than efficient to build only a 4-Train LNG plant?

Total capital costs for all project sectors were $28.5 billion, including $16.8 billion for the LNG plant.

- Are estimated capital costs too low? Some single train LNG plants have costs more than what was assumed for this 4-Train plant. A high proportion of energy sector "megaprojects" overrun their original budgets by a sizable percentage.
- Are costs too high and consequently understate the real returns to investors?
- Are there any benchmarks to compare costs?
- Have the appropriate range of sensitivity analyses been run and evaluated?

No Condensate or LPG has been included.

- If indeed there would be some condensate or LPG extracted from the gas stream both the capital costs and the resultant net revenues would be higher and project economic results would likely improve.[18] What would these look like and what fiscal terms (upstream or LNG) would be applied?

Analyzing and Evaluating the Results

Below are a few selected key indicators from the base case:

Selected Item	Upstream	Gas Pipeline	LNG Plant	Consolidated
Capital Costs, $Millions	5,290 * 2	1190	16,768	28,538
Gas Production	34 TCF			
NPV at 10%, $Millions	3,655	-83.4 [19]	4,472	7,745
IRR	19%	9%	14%	15%
Total Government revenues undiscounted, $Millions	28,216 * 2	1119.6	26,030	83,582
Government Take, undiscounted	50%	32%	31%	50%
First Year that Govt revenues exceed $2 Billion p.a.				2026
First Year that Investor Net Cash Flows exceed $2 Billion p.a.				2022

Some questions that might arise from these results:

- Are the relative IRRs for each project sector (e.g. upstream 19%, gas pipeline 9%, LNG plant 14%) reasonable compared to their risks and to other similar investments around the world or the region?
- Do the NPVs at 10% seem reasonable for each project sector relative to the size of the investment and the risk? Are these sufficient to attract the investment but at the same time not yielding too much of the rent?
- How do these IRRs or NPVs change using different assumptions? Check the sensitivity analysis to see whether these indicators collapse due to changes in the assumptions.
- The timing of cash flows is critical in determining NPV and IRR. Check the impact of a production delay of field 1 in the sensitivity analysis.
- Timing of cash flows is also important to the government in terms of the government treasury's overall budgeting for inflows and spending or managing of sovereign wealth

[18] Part of the liquids can be sold on the same price terms as oil and be processed by the same facilities as oil. Some other liquids need additional processing that is a little more expensive in order to be sold. However they can still be relatively easily exported as liquids using a range of widely available vessels into quite a few open markets. Therefore high liquids content in a natural gas project significantly enhances its profitability and can enable producers to charge a lower price for gas. This can make the difference between a gas project being economically viable or not. When the liquids are liable to a high tax rate (e.g. oil tax rates), this economic benefit can be minimized for investors. Therefore, it is important to consider how condensate is treated under differentiated fiscal terms, as this can influence the pace of development of the gas industry (See: http://ccsi.columbia.edu/files/2014/03/Overview-APG-Utilization-Study-May-2014-CCSI1.pdf)

[19] The NPV of the pipeline is negative because we set a discount rate of 10% above the IRR of the project (9%). Pipelines generally make a lower return given limited operational and market risks. When pipelines are owned by the same investors as the upstream or the LNG facility, they might even be a cost center making a lower return.

funds. It can also be instructive in evaluating the distribution between the government and the investors. Looking at the base case the first year of significant NET cash flows to investors is 2022 when they earn over $2 billion net, whereas the government does not reach $2 billion a year until 2026. The reality is that the Government does not receive much of their inflows until the second half of the project life, whereas the investors reach their net inflows right after production start.

- Overall percentage split of government take is another important indicator. In the upstream sector the government take is 50% of the total net cash flows, but is only 31-32% for the gas pipeline and LNG sector. This is a reflection of the fiscal and tax terms which are typically much higher in the upstream. But when these are compared to other similar projects with similar risks in other countries to evaluate, do they look to be competitive and consistent?

6. What the model does not include

1. Technical Input Data - The model does not create forecasts of production, costs or prices. These must be obtained from a reliable source such as one of the companies that are investing in the projects, the government or an assessment from an independent party such as an engineering firm, a consultant, a bank, or an international organization. If such detailed data is not available, it becomes even more important to test the economic results by running scenarios with wide variation in the input data.

2. Exploration costs – This model focuses on the decisions to be made after a discovery has been made, so exploration costs are not included (only some of it as recoverable costs under the PSA are included). However, fiscal treatment of exploration costs could become a factor if past "sunk" exploration costs are permitted to break the "ring fence" to be used in cost recovery. At some point this may become a negotiating point in projects going forward and have an impact on the economics.

3. Full Decommissioning Costs Functionality – Decommissioning costs have been included as an upstream input item. However, this can be complex for a couple of reasons. One is that these costs are often required to be pre-funded by the upstream partners accordingly to a complex and sometimes arbitrary formula, and the related cost recovery or tax deductibility treatment can vary significantly. If the costs take place at the end of the field life then loss carryback provisions must be considered, which creates an added complexity. And decommissioning is not straightforward for fields that are feeding into an LNG plant. Oftentimes an individual field may stop producing, yet its infrastructure may end up being used or leased for many years by other suppliers to the LNG plant as processing, compression stations, transportation, treating or even gas storage. This means the ultimate decommissioning from any one field may be delayed by years. Consequently, the model only includes provision for a very simple pay as you go cash basis funding and no loss carryback provisions for tax or production sharing.

4. Differentiation of investor equity shares – With the exception of the NOC, the model does not differentiate between the respective investor equity shares in the various segments. They are treated as one group for each segment.

5. Withholding Tax on Dividends – No provision has been made in the model since withholding tax in many cases is really just a minor timing difference on payment of corporate taxes. In other cases with tax treaties the companies get a full relief or credit for withholding taxes. In the event that the WHT in any place does not have these types of "relief" features and it becomes a real final tax, the model can cover this through utilizing the other tax components (surcharge or special tax) that have been set up in the model.

6. Non Quantifiable Financial Results – Economic models typically focus only on quantifiable financial results of a project. Most agreement and regulatory provisions do have financial impacts and these can be reflected. However, many other project agreements and petroleum regulations have consequences that cannot be easily modeled. Some of those include:

- Control of project decisions, such as: approving projects going ahead, moving into the development phase, relinquishment, sales of interest, contracting and procurement.
- Local content and local employment requirements and policies
- Environmental regulations and standards,
- Community engagement and consultation
- Control and compliance of oilfield services contractors and their impact
- The Sale and Purchase Agreement itself may protect the upstream and the LNG plant investors from a variety of market and operations disruptions through send-or-pay or take-or-pay clause.