Columbia Center on Sustainable Investment
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Manual for the Open LNG Regasification Model

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Terms & definitions

- **The LNG Sale and Purchase Agreement (SPA)** is the keystone of the LNG project and is the contract between the liquefaction plant and the receiving regasification terminal ("Regas plant"). The main terms of an LNG SPA include: Term (duration), Transportation arrangements, LNG Volume, Minimum Level of Commitment (based on Annual Contract Quantity and usually referred to as Take-or-Pay from Buyer and/or Send-or-Pay from Seller), Cargo Discharges, LNG Price.
- **The Natural Gas Sales Agreement (GSA)** for the sale of natural gas out of an LNG import project utilizes this type of agreement between the regasification entity and the buyer of the gas coming out of this regas plant. The key GSA terms to focus on are: the commitment of the buyer to purchase natural gas and whether there is a take-or-pay obligation; price and payment terms; ability of the buyer to withhold payment or dispute invoices; what constitutes force majeure for the buyer; liability for natural gas that is off-specification; and the LNG import project's liability for delivery shortfalls.
- **ACQ (Annual Contract Quantity)** is the volume of gas which the seller must deliver and the buyer must take in a given contract year.
- **TOP (Take or Pay)** is a common provision in LNG and in gas contracts under which, if the buyer's annual purchased volume is less than his purchase obligation (the Annual Contract Quantity minus any shortfall in the seller's deliveries, minus any Downward Quantity Tolerance to reflect plant maintenance and seasonal variations in demand), the buyer pays for such a shortfall as if the gas had been received. In some cases, this TOP payment can be reduced if the seller is able to find alternative customers for any gas not taken.
- **CF (Carry Forward)** is a provision within a long term Take or Pay Contract under which a buyer which takes more than its Annual Contract Quantity in any year is allowed, under conditions specified in the contract, to balance this against under taking in following years.
- **Terminal (or Facilities) Use Agreement -** In an LNG import project, depending on the project structure, the user of the terminal will enter into a terminal use agreement with the terminal owner. There are a wide variety of titles for this agreement, although they accomplish the same purpose - use of the terminal for a fee, often involving a minimum throughput obligation on the part of the users sometimes referred to as a capacity Reservation Fee.
- **Operations and Maintenance Agreement (O&M)** - should include: the services and scope of the services to be provided; the standard of performance; the term of the agreement; the responsibilities and liabilities of the operator and the terminal owner; budgets and necessary costs; payments and incentives to the operator; employees, including local employees, and services, including local services, to be used by operator; rights to suspend and terminate early; and owner's rights to monitor and inspect.
- **Port Use Agreement -** LNG import terminals often fall under the jurisdiction of a particular port and are subject to the port's port use agreement. Where the terminal is considered its own port, the terminal will adopt its own port use agreement. The port use agreement is a set of rules and requirements applicable to all vessels using the port and address a variety of operational and other topics, including responsibility for damages and other liabilities. The

LNG import terminal is then responsible for ensuring that each LNG vessel calling at the terminal agrees to comply with the port use agreement.

- **Gas Transportation Agreement** is the agreement with the Gas Pipeline owner addressing the services they provide to transport the natural gas to the user, often for a tariff fee per volume transported. It also typically includes a minimum throughput volume and a related Reservation Fee.
- **Power Purchase Agreement -** In many situations today, an LNG import project will be bundled with a power generation option. In such situations, the output of the LNG import project may include electricity. In these situations, a Power Purchase Agreement will be required
- **CCGT (Combined Cycle Gas Turbine)** A Combined Cycle Gas Turbine (CCGT) is a form of electricity generation plant in which the waste heat produced from combustion of gases is partially captured in the turbine exhaust and used to generate steam for production of additional electricity, significantly increasing the efficiency of the electricity generation.
- **LCOE (Levelized Cost of Electricity) -** LCOE is the net present value (NPV) of the power unit-cost of electricity ($/MWh) over the lifetime of the asset. It considers investment (incl. financing), operations and maintenance and fuel expenditures weighed by the operating conditions.

*Sources: Adapted from EIA and '**Understanding Natural Gas and LNG Options'** Handbook from Power Africa (US DOE) (https://www.energy.gov/ia/articles/understanding-natural-gas-and-lng-options-handbook)*

Abbreviations

$MM – Million dollars
BTU – British Thermal Unit
CAPEX – Capital Expenditures
CCGT – Combined Cycle Gas Turbine
CM – Cubic Meters
DES – Delivered ex ship
FID – Final Investment Decision
FOB – Free On Board
FRSU – Floating Regasification and Storage Unit
ICE – Intercontinental Exchange
JCC – Japan Customs-cleared Crude
LCOE – Levelized Cost of Electricity.
LNG – Liquefied Natural Gas
NBP – National Balancing Point
MCF – Thousands of Standard Cubic Feet
MCM – Thousands of Cubic Meters
MT – Million Metric Tons
Mtpa – Million tons per annum
MWh – Megawatt-hour
OPEX – Operation Expenditures
OTC – Over-the-Counter
PPA – Power Purchase Agreement
Regas – Regasification Unit (FSRU)
TOP – Take or Pay Clause

1. Introduction and purpose of this model

This model has been developed in collaboration with the Commercial Law Development Program (of the United States Department of Commerce) to be used for training purposes and to be adapted for countries that are looking at LNG regasification projects. It models the gas value chain: LNG market -> regasification -> pipeline -> power generation. LNG regasification is an emerging flexible energy sourcing arrangement that has resulted from improved liquefaction technologies and increasing trade of natural gas.

A financial/fiscal model provides forecast returns of a project to the investor and government, and can help identify the main risks associated of the project. These estimates are based on fiscal, market, technical and corporate input variables, many of which are averages and/or forward looking assumptions. A model is fundamental to help answer the following questions:

- What is the "fairness" of the current and potential deals?
- Who bears costs and risks associated with the project?
- What is the trade-off between government investments and private participation?
- What is the efficiency of tax incentives?
- How do changes in the ownership and commercial structure affect the financial flows to both parties?
- How do revenue flows alter if prices change?

Stakeholders tend to use financial/fiscal models for different purposes. Below is a list of purposes that this model can help with, listed by stakeholder type.

Investors in the Regasification Facility – Assess the economic viability of their investments under a range of operational and market risks on the gas supply and demand side.

Governments and Public Utilities – Ensure that projects are economically viable and attractive to investors without giving away unnecessary government revenues. For planning and budgeting purposes, governments can use the model to forecast how much costs and revenues can be expected from the project/sector, the timing of those expenses/receipts and their potential volatility over the life of the project. This is particularly important for countries with comparatively small budgets. Public utilities can use the model to evaluate whether their share of the project investment has sufficient returns to be financed by lenders.

Civil Society – Assess whether tax incentives such as income tax exemptions/tax holidays are needed to make the project viable and review appropriateness of investor returns. Civil society can also use the model to review government participation and budgetary impacts. The key challenge becomes gaining access to the assumptions that are necessary to perform such a modeling exercise.

Gas Buyers and Sellers - Assess the basic viability and reliability of the project under a variety of future market conditions.

To support project negotiations, it is crucial for governments to develop their own fiscal model to assess returns to the investor and the revenues to the government. Ideally the company and government then 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, demand, costs, feedstock sources to a plant, etc; which may lead to an impasse in negotiations given that the government and investor cash flows 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.

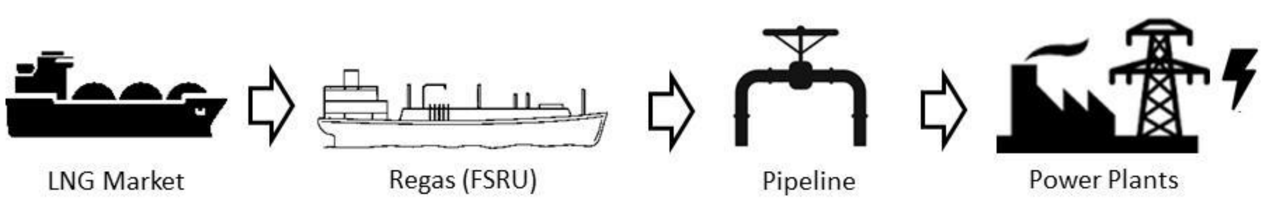
We note however that in agreeing on assumptions, the government should recognize that the companies usually have more experience and information. So a comprehensive description and discussion of the assumptions is a vital step to assure a balanced understanding and identification of risks to the government.

2. Background

a. LNG-to-power value chain

The natural gas value chain projects are complex, which requires a detailed assessment. This can be traced back to the following primary reasons: (1) neither natural gas nor power can be easily stored. Thus, in the natural gas segment, there are costs of transportation (pipeline and tankers) and treatment (separation of liquids, liquefaction and regasification) which might increase if there is a poor coordination between gas supply and demand. On the power component, interruptions to gas-fired power plants could lead to power outages having significant adverse impacts on the local economy. (2) Stable operations and economies of scale are often required for regasification facilities to be economically and operationally viable. Consequently, long term contracts with volumetric commitments and an agreed price mechanisms are needed to provide security to the investors. However, as gas markets evolve the spot LNG market is expected to take a bigger share of total gas supply in the near future.

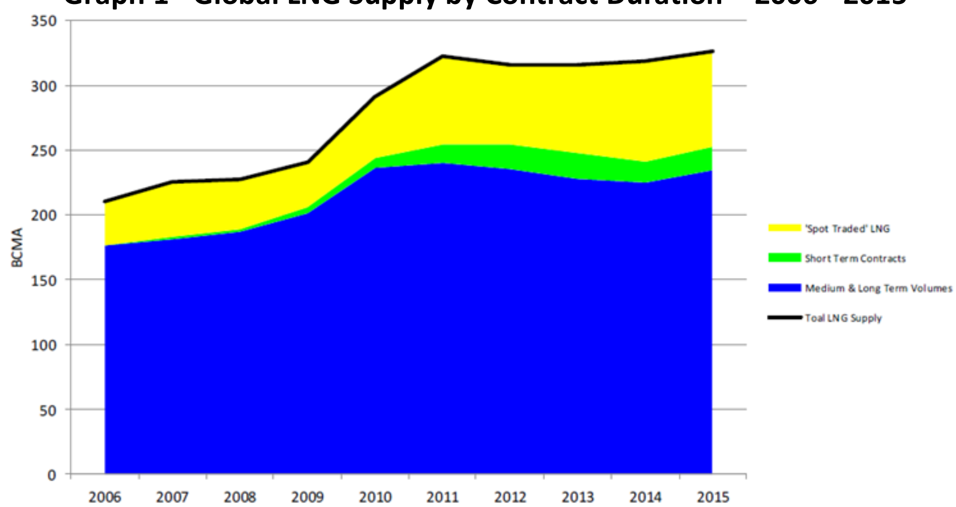
Because of the interdependence between gas segments, different business models or ownership structures can be considered to allocate costs, risks and returns to private and/or public agents. The figure below outlines the 4 main segments:



LNG Market – LNG markets are where buyers and sellers of LNG negotiate the contracts (long-term or spot). Long-term contracts have been traditionally the main option due the need to ensure stable revenues to remunerate large scale and capital intensive infrastructure projects (liquefaction and regasification plants). Traditionally, the buyers (often gas or power utilities) would contract LNG from liquefaction plants through contracts with minimum 'Take-or-Pay' obligations with destination constraints (no rights to re-sell/divert LNG cargoes) and price formulas linked to oil. As new gas capacity comes online and more players are involved, the spot market (ie: no volume commitment) is developing.

The figure below shows the development of the LNG market and the rising proportion that the spot market makes up.

Graph 1 - Global LNG Supply by Contract Duration – 2006 - 2015



Source: OIES (Rogers), 2017

Regasification – A regasification facility can be an onshore LNG terminal or an offshore Floating Storage and Regasification Unit (FSRU). The traditional approach was to build an onshore terminal to cool down the LNG and supply local gas systems. Onshore LNG terminals benefit from higher economies of scale and lower operating costs. Furthermore, capacity can be more easily expanded and local content tends to be higher. Offshore FSRU technology has become a fast growing alternative.[1] FRSUs are characterized by lower costs for smaller capacities, faster schedules[2] and commercial flexibility as the unit can be relocated after contract termination. As they are often leased, FSRUs require less upfront capital.[3] The lease is often a 10-12 year agreement which includes the facility plus operation and maintenance. For its operation FSRUs require investments in mooring and onshore receiving facilities.

Pipeline(s) – After re-gasification (changing the gas from its liquid form back into gaseous state)

[1] The FSRU business is relatively recent. In 2001, El Paso contracted with Excelerate Energy the first FSRU vessel for its project at the Gulf of Mexico.

[2]A new FSRU can cost around 50-60% of an onshore terminal and be delivered at half the time (OIES [Songhurst],2017).

[3] These leases still require credit support from the lessee that may be expensive to provide if not a credit worthy entity.

the gas must be transported to the consumers. This is done via pipeline. The pipeline must be designed and operated based on contractual volumetric commitments from both suppliers and customers. The pipeline may be owned by the same investor as the regasification terminal, or unbundled whereby another operator or the public utility owns the pipeline. Unbundling ownership from the regasification terminal can allow more competition for the use of pipelines' capacity (if there are other gas projects). As pipelines are strategic assets that can be monopolized, access rules might be required to prevent abuse of market power.

Power Plant(s) - Gas-based power plants vary widely in investment costs, efficiency and capacity. They can be designed for base-load capacity or just turned on during peak hours. The design will have a fundamental impact on the required gas feedstock and the plant's operation. Also electricity tariff and pricing structures vary significantly by country and whether only the utility or also private companies are allowed to feed the grid. All these specificities need to be reviewed and adapted to the gas value chain.

b. LNG-to-power structures

The model allows users to test the following four LNG-to-power structures:

Table 1 – Summary of LNG-to-Power Models

	Model 1 Tolling		Model 2 Merchant		Model 3 Partially Integrated		Model 4 Fully Integrated	
	Private	Public*	Private	Public*	Private	Public*	Private	Public
LNG Market	-	Purchases LNG	Purchases LNG	-	Purchases LNG	-	Purchases LNG	-
Regas	Owns/ leases & operates	Pays a toll to use the private regas.	Owns/ leases & operates, sells NG	Buys the gas from the regas -	Owns/ leases & operates	-	Owns/ leases & operates	-
Pipeline(s)	-	Builds, owns and operates		Builds, owns and operates	Builds, owns and operates, sells NG	Buys gas from pipeline-	Builds, owns and operates	-
Power Plant(s)	-	Builds, owns and operates, and sells power*	-	Builds, owns and operates, and sells power*		Builds, owns and operates, and sells power*	Builds, owns and operates, and sells power*	-

*Users can decide whether power plant is owned by a public utility or a third party.

1. ***Tolling Model*** – whereby the investor owns/leases and operates the regasification unit and charges a fee to regasify the LNG. The government utility purchases LNG and operates the gas pipeline and power plant. The model also allows for a third party to own the power plant.

2. ***Merchant Model-*** whereby the investor owns/leases and operates the regasification unit.

The investor purchases LNG and sells gas at the entrance of the pipeline which is run publicly.

3. ***Partially Integrated Model-*** whereby the investor owns/leases and operates the regasification unit and pipeline. The investor purchases LNG, regasifies it, and transports the gas to be sold to the power plant (government or third party-owned).

4. **Fully Integrated Model –** whereby the investor owns/leases and operates the regasification unit, gas pipeline and power plant. The investor purchases LNG, regasifies it, transports it to the power plant, converts it into electricity and then sells the electricity into the power grid.

The model allows users to choose whether the public utility or a third party owns and operates the power plant in all cases but model 4 (where the power plant is owned and operated by the private company buying the LNG as said above). When the public utility option is chosen, the model provides an overview of the resources needed by the utility to take on this investment and the returns it can expect. When a third party is chosen, the model does not calculate the economics for the portion of the value chain that this third party takes on.

c. Risks and mitigation mechanisms

Apart from estimating the returns and revenues from the various components of the LNG-to-power value chain, *the main benefit of this LNG regasification model is to help stakeholders identify risks under the various commercial structures and quantify impacts of unforeseen events.* Below is a list of key risks that stakeholders should be aware of. The model can be used to quantify potential impacts.

- **Project/infrastructure**
    - *Design capacity*: building the plant at overcapacity due to unrealistic demand forecasts;
    - *Construction*: construction delays or cost overruns;
    - *Complementary infrastructure availability*: lack of coordination between complementary infrastructure needed to make the project viable (e.g. port facilities, pipeline, transmission lines, etc.)
- **Operational**
    - *Operational schedules*: lack of alignment of repair and maintenance schedules leading to shut-ins;
    - *Operation between segments:* lack of coordination during operations resulting in below-capacity production;
- **Commercial/Market**
    - *Volumetric commitment:* lack of alignment between LNG sales to the regasification

plant and gas requirements by the end users;

- *Gas Prices*: volatile LNG prices can affect trade margins if the gas prices to end consumers are not indexed to LNG prices. However, if changes were passed through consumers, they would affect the level of competitiveness of final products (e.g. electricity prices);
- *Electricity sales:* Missing mechanism between US$ denominated LNG feedstock prices and electricity prices often denominated in local currency.

Each model structure allocates responsibilities and risks to private and public parties. For instance, without risk mitigation mechanisms in place, LNG price risk would be borne by the government in the Tolling structure while in the other structures the investor takes on this risk. The power price risk is always faced by the utility, which is run by the investor only in the fully integrated arrangement. Other risks, such as oversizing facilities and operative shut downs are risks that are shared among segments. A shut down of the power plant impacts the operation of the Regasification unit, the Pipeline and the LNG buyer. In turn, cost overruns primarily impact the investor of the relevant facility but might impact the final cost of delivering gas throughout the value chain.

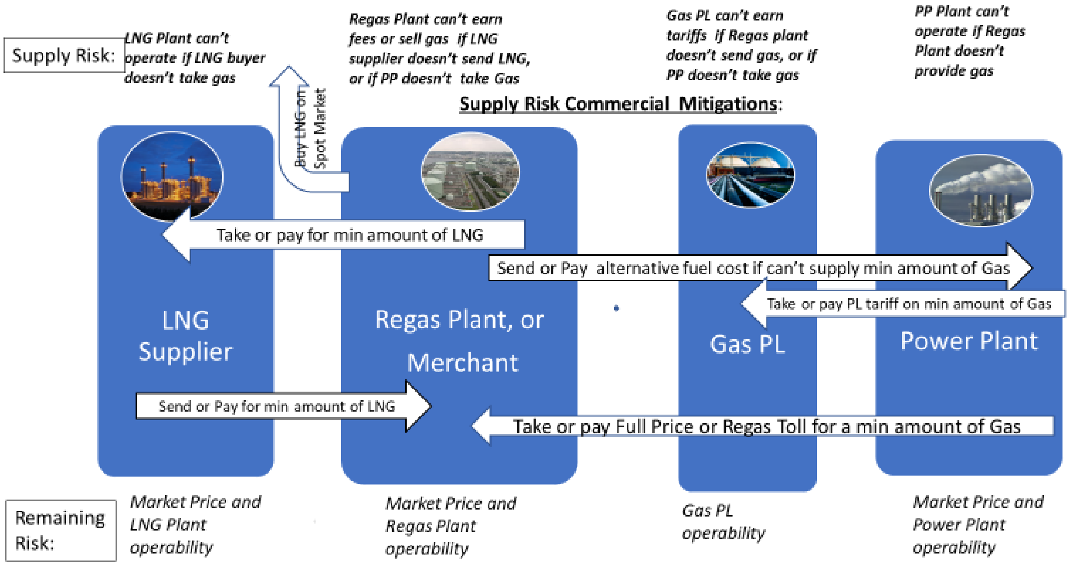
To address some of these risks, LNG agreements (other than spot sales) typically require buyers to commit to take a certain minimum volume of LNG or gas in order to avoid disruptions to operations. Those minimum volume commitments must be paid for even if they are not taken or at least require the buyer to compensate the seller for any losses from selling to an alternative source. Typically, the buyer of the LNG for regasification will also require similar minimum volume commitments from its own natural gas customers. These are termed “Take or Pay” obligations and can be especially burdensome in a situation where the ultimate customer (power plant) experiences variability in its level of operation.

Most long-term LNG sales contracts also require the LNG seller to always provide a minimum volume of LNG or else have to compensate the LNG Buyer. These are termed “send-or-pay” obligations.

A tolling basis regasification plant or a tariff-based gas pipeline may also require a minimum throughput. Failure of a user to provide such a minimum volume may require the payment not of the full value of the gas but of a tariff or toll based fee (usually intended to cover a pro-rata share of the operating and capital costs) for the shortfall, often termed a “reservation fee”.

In many long-term contracts, these take-or-pay obligations may only apply for the first X number of years and expire after that. The following chart represents a typical series of commercial arrangements and the resultant impacts on risks.

Figure 1 – Supply Risks and Commercial Mitigations



d. Risk allocation in different structures

It is important to understand how the model treats these risks. The model assumes:

1. LNG Supplier is always able to supply the minimum amount of LNG to the LNG Buyer. There is no provision for the impacts of a Send-or-Pay from the LNG Supplier.
2. LNG Buyer provides Take-or-Pay obligation to LNG Supplier due to risk of Power Plant not taking the gas.
3. Power Plant provides a Take-or-Pay obligation to LNG Buyer.
4. The LNG Buyer provides a Send-or-Pay obligation to Power Plant for minimum volume. But the risk of Regas Plant or Gas Pipeline having operability problems (other than Force Majeure) that would cause them to operate below minimum volume obligation for extended period of time was deemed to have very low probability due to the relatively simple technical nature of these operations; and even if it did occur, the T-O-P or S-O-P obligations are likely to be set up so as to allow some flexibility for make-up in subsequent periods. Consequently, even though the commercial structure might include such a requirement the model assumes that a minimum throughput obligation for the Regas or Gas Pipeline owner will have no impact.
5. In the Tolling case, LNG Buyer or Power Plant would pay a minimum throughput or Reservation Fee to Regas plant to compensate for operating and lease costs if the Power Plant cannot take above minimum volume.
6. No Reservation Fee (or Gas Pipeline tariff) is assumed to be paid to Gas Pipeline owner since in all cases the model assumes that the Gas Pipeline owner earns its profits from buying and selling natural gas, not merely acting as a pipeline operator or fee earning transporter.

7. Any impact of the LNG Buyer not being able to take full amount of LNG Take or Pay will be offset by a corresponding Take or Pay obligation from the Natural Gas Buyer, i.e. the Power Plant. The Regasification spreadsheet includes these impacts.

The model assumes that LNG transactions are long term transactions. If they were spot, the following implications would be considered:

- For a buyer of LNG more use of spot market will mean greater price fluctuations, but these may even out over the course of a year or a project. So there may not be much impact over the course of a long-term analysis, but certainly could have ramifications over any shorter term period.
- Also, greater use of the spot market will mean more flexibility to the buyer (the power plant) in avoiding take or pay penalties resulting from a power plant that does not operate at a consistent level of its capacity. The flip side of that situation is that for a smaller buyer they may not be able to easily obtain the volumes they need during upticks in power plant usage without paying a higher price.
- But probably the key risk is that more spot market participation will make it less likely that a financial institution will lend to the builder of a Regas facility or power plant. Currently most lenders look at term sales as a means of providing predictability on prices and volumes and often establishing a certain percentage of term contracts is a condition of the loan. The model does not provide a ready means of analyzing that risk other than perhaps suggesting that the interest rate on any financing analysis should be set slightly higher to compensate the bank for waiving that condition.

3. Using the model

a. Structure

The model is composed of 10 worksheets, which are linked by formulas. Table 2 provides an overview of the function of each worksheet. The worksheets are color coded, with the blue worksheet ('Inputs' sheet) being the place where users can input all variables and the white worksheet (‘Dashboard’ sheet) where they can observe the compiled results. Users are likely going to spend most of the time in these two worksheets.

Table 2: Worksheets of the model

Name of Worksheet	Description
Cover	Gives background information on how to operate the model.
Dashboard	Main results from analysis
Inputs	Assumptions are input
Regasification	Economics of the regasification facility
Pipeline	Economics of the gas pipeline
Power Plant	Economics of the Power Plant

Private Company Consolidated	Consolidation of the economics of segment owned by the investor (according to the commercial structure chosen)
Govt Utility Consolidated	Consolidation of the economics of segment owned by the Government Utility (according to the commercial structure chosen)
Govt Utility Financing	Computation of the debt schedule and cost from financing the Government utility
Project Consolidated	Economics of the entire project: Regas, Pipeline and Power Plant (according to the commercial structure chosen)

The cells in the model are also color coded to facilitate the navigation of the model. Table 3 explains each color coded cell used in the model.

Table 3: Color-coding of cells in the model

Color	Description
Light blue	Input variables that can be changed by the user. Price, production and cost should be all edited in the 'inputs' worksheet.
Light green	Section dividers
White	Fields that are linked by a formula in the model and should not be changed as it may result in malfunctioning of the model
Red font	Explanatory notes or highlighted assumptions within the model

The user can pick the model that should be calculated in Cell B5 in the 'Inputs' worksheet. When operating in the dashboard, the user can also make the model selection at the top of the page. *It should be noted that the 'switch' is not linked, therefore changing the model at the 'Dashboard' modifies the switch at 'Inputs' but not vice versa.* Moreover, the user can decide whether the power plant is publicly run or third party - run (Cell B9 in the 'Inputs' worksheet) and if the regasification unit is leased or treated as a capital cost (Cell 38 in the 'Inputs' worksheet).

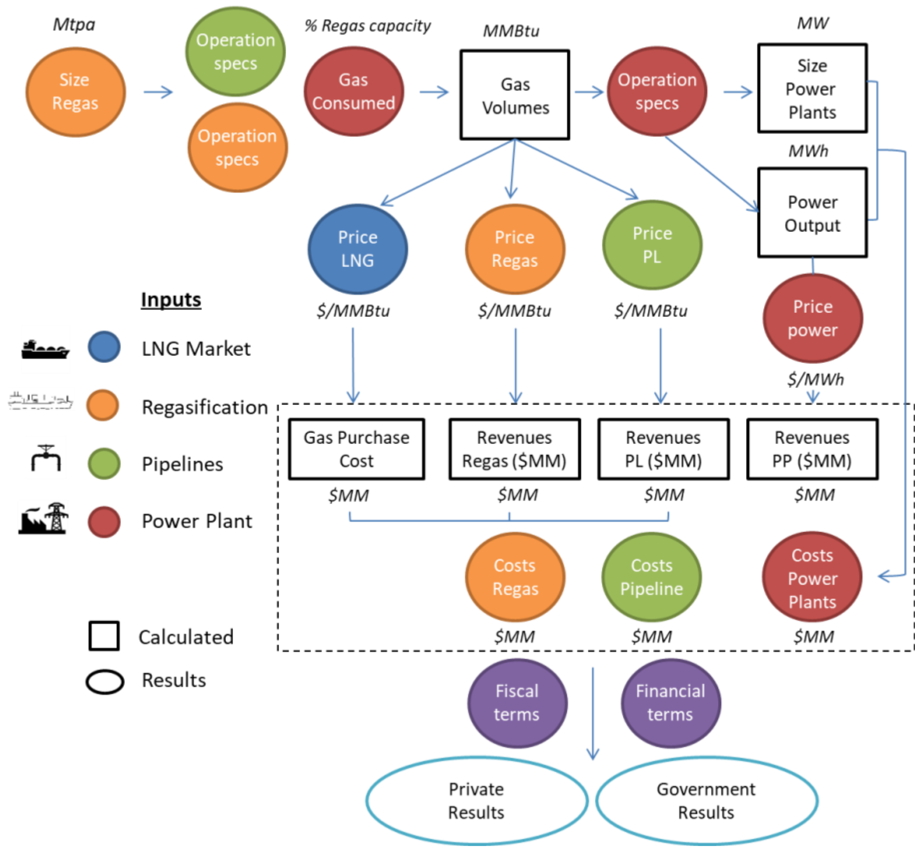
b. Calculations and Outputs

Understanding how the model works[4]

The model is built considering the LNG regasification arrangement as the centerpiece of its calculations. Figure 2 presents the main required inputs and how they are interlinked. First and foremost, the user will need to input the regasification unit capacity based on the ultimate expected demand from the power plant (in million tons per annum – Mtpa). A small proportion of the gas will be used to operate the regasification plant and pipeline facilities (see also figure 3 below). The other inputs for each component along the chain include the capital costs, operating costs and prices.

[4] 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.

Figure 2 – Model's main inputs and calculations



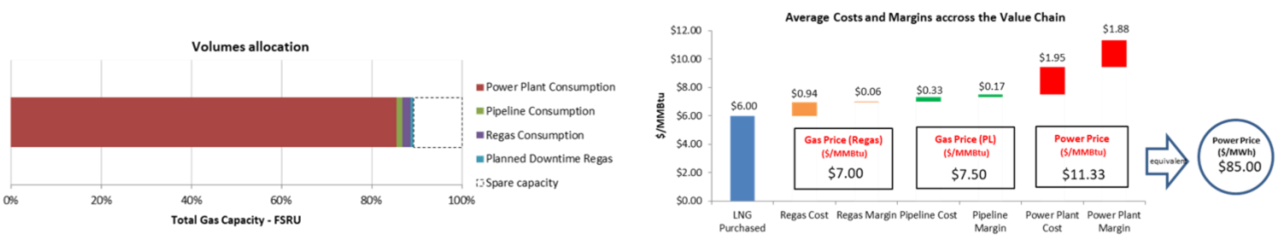
In regard to prices, the model assumes that prices along the value chain are separate independent inputs: (i) LNG purchase price DES at Regas import terminal; (ii) Gas price at exit from Regas into gas pipeline; (iii) Gas price as sold at entrance of Power Plant; (iv) Electricity price at entrance of the Grid. Therefore, users must input or change them accordingly to ensure that each segment remains viable. In practice, as discussed before, prices are agreed through contracts and set according to negotiated formulas. In many cases the transfer price between segments or parties may be partially linked by a formula in the sale and purchase agreements as a means of reducing risks. In any case, gas prices are set by world market factors but power prices are further influenced by Government utility consumer pricing policies.

Fiscal and financial terms need to be input to determine the project economics. Incentives such as a tax holiday or tax reductions can be input on an annual basis. Finally, the model presents the project results, the results for the investor ("private") and for the government. The allocation of economic costs and benefits will be fully dependent on what commercial structure was chosen.

Understanding the results

• **Understanding the volumes, costs and margins along the value chain:** The first two figures in the 'Dashboard' worksheet (figure 3 below) show the interaction among the various sections of the LNG-to-power value chain. The volume allocation graphic shows users where the gas is allocated, which is mostly to the power plant as explained above. <u>*It is important to not include the gas used or lost along the value chain in the financial analysis as this would result in too optimistic results*</u>. The second graphic shows the costs and margins that have been converted into $/MMBtu for comparability purposes (eg: the final power price (85 $/MWh) is equivalent to $11.33 per MMBtu). The largest expenditure is the purchased LNG ($6 per MMBtu) followed by the power plant ($1.95 per MMBtu). These estimates consider the cost/revenues in each segment divided by total gas volumes from the Regas unit. The cost of gas used and lost through the value chain is allocated to end users.

Figure 3 – Allocation of gas volumes, costs and margins



• **Assessing the different LNG-to-power structures:** When assessing the commercial and legal ownership structures for the project it is important to understand how each structure allocates costs, revenues and risks. The tables in the 'Dashboard' summarize the calculations of the model. The consolidated tables copied out below, highlight the project returns, expenditures and taxes paid under the different models; and allocates these to the investor and the government utility. It should be noted that the model does not take into account the risks outlined in section 2. The results need to be viewed keeping the risk allocation in mind given that if the investor is taking on higher risks, he/she will require higher returns.

From a government perspective these tables can provide answers to the following questions:

- Are the returns of the project high enough to attract investors?
- How much revenues can the government expect from the project?
- How much money does the utility need to finance the capital expenditures if it takes on one or several components of the power-to-LNG value chain?
- How much money does the utility need to calculate for operating expenses on an annual basis if it takes on one or several components of the power-to-LNG value?

Table 5 - Summary table: Regasification plant is built

Consolidated												
	NPV[1] ($MM)		IRR[1] (%)		CAPEX[2] ($MM)		OPEX[2] ($MM/yr)		Net Cashflow ($MM)		Taxes Paid[3] ($MM)	
Project	**1,204.8**		**10.7%**		**4,288.8**		**230.2**		**10,130.2**		**3,376.4**	
Model	Private	Gov	Private	Gov	Private	Gov	Private	Gov	Private	Gov	Private	Gov
1	*(6.3)*	*1,211.1*	*7.4%*	*11.2%*	*611.0*	*3,677.8*	*81.7*	*148.5*	*838.7*	*9,291.6*	*276.2*	*3,100.2*
2	*(20.7)*	*1,229.1*	*7.0%*	*11.2%*	*611.0*	*3,677.8*	*86.7*	*143.5*	*795.7*	*9,348.9*	*287.1*	*3,075.0*
3	*58.3*	*1,150.1*	*8.3%*	*11.2%*	*932.1*	*3,356.7*	*108.8*	*121.4*	*1,483.8*	*8,660.8*	*514.0*	*2,848.1*
4	*1,208.4*	*N.A.*	*10.7%*	*N.A.*	*4,288.8*	*N.A.*	*230.2*	*N.A.*	*10,144.6*	*N.A.*	*3,362.1*	*N.A.*

Overall Project's Results

Results by Model

Allocation by Private and Government

Table 6 - Summary table: Regasification plant is leased

Consolidated												
	NPV[1] ($MM)		IRR[1] (%)		CAPEX[2] ($MM)		OPEX[2] ($MM/yr)		Net Cashflow ($MM)		Taxes Paid[3] ($MM)	
Project	**1,339.4**		**11.0%**		**3,677.8**		**279.5**		**9,493.2**		**3,147.3**	
Model	Private	Gov	Private	Gov	Private	Gov	Private	Gov	Private	Gov	Private	Gov
1	*128.3*	*1,211.1*	*10.1%*	*11.2%*	*0.0*	*3,677.8*	*130.9*	*148.5*	*201.6*	*9,291.6*	*47.1*	*3,100.2*
2	*113.6*	*1,229.1*	*9.8%*	*11.2%*	*0.0*	*3,677.8*	*136.0*	*143.5*	*157.4*	*9,348.9*	*59.3*	*3,075.0*
3	*192.6*	*1,150.1*	*10.1%*	*11.2%*	*321.1*	*3,356.7*	*158.1*	*121.4*	*845.5*	*8,660.8*	*286.1*	*2,848.1*
4	*1,342.7*	*N.A.*	*11.0%*	*N.A.*	*3,677.8*	*N.A.*	*279.5*	*N.A.*	*9,506.3*	*N.A.*	*3,134.2*	*N.A.*

- *Net Present Value (NPV)*: to achieve a return greater than the discount rate this figure must be positive. The more integrated, more opportunities for returns may be required by investors in exchange for taking on more risks. Conversely, the more risks taken on by the Government Utility the greater the returns they might expect, or at least less profit/fees having to be paid to private investors. 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).

- *Internal Rate of Return (IRR)*: The IRR is the discount rate at which NPV=0. This must be higher than the cost of capital and aligned with the amount of risk the investor takes on. The higher the IRR, the more attractive the project. Notice that, the power plant project is significantly larger than the other components along the gas-to-power plant value chain. Moreover, the results for the FSRU lease option cannot be compared to the other figures, given that this result includes the financing of the project.

- *Capital Expenditures (CAPEX)*: this is the investment needed for fixed assets such as land, buildings and machinery. A large proportion of this spending will occur up-front. In the table above, under models 1 and 2 the investor takes on the capital cost for the regasification unit and the government utility for the pipeline and power plant project. Under model 3 the capital expenditure for the pipeline is shifted from the utility to the investor. Under model 4 all capital costs are born by the investor.

- *Operating Expenditures (OPEX)*: this figure shows the annual operating and maintenance cost (excluding the gas purchase cost). This figure is expressed in nominal terms. The explanation for the different OPEX figures is the same as for the CAPEX figures, with the exception of the small difference between models 1 and 2. This is because in the merchant model (model 2) the government does not pay the administrative and marketing costs (which is paid by the LNG buyer). Note that, if the regasification unit is leased, its costs shift from CAPEX to OPEX. Additionally, a lease entails that financing costs are added to the payments to the FSRU owner which would increase the costs. A capital/financing lease of the FSRU means that cash flows are "leveraged" which means that NPV and IRR are not as meaningful. Consequently, an "unleveraged" NPV and IRR are also computed in those cases.

- *Net Cashflow*: shows how much cash is available after expenses and taxes over the lifetime of the project. Investors, government and lenders may want to know how strong the cash generation is compared to costs. This figure is expressed in nominal terms.

- *Taxes Paid*: revenues that the government will receive from the project. The government may want to compare these with subsidies provided, or disbursements made from its utility participation. Taxes reflect mainly revenues from income tax. Note that, if the option of a third party private owner for Power Plant is chosen (cell B9 in the Inputs tab), tax payments by the third party are not expressed at consolidated tables.

• **Checking that project and investor returns are reasonable by segment:[5]** As highlighted above, users should check the NPV and internal rate of return IRR of the project as a whole. Users should also check each segment. This can be done in 'Dashboard' worksheet by expanding the 'regas', 'pipeline' and 'power plant' sections as outlined in the figure below. If the results show that the individual segments are earning much lower or much higher rates of return than expected, it may be a sign that the assumptions need to be reviewed or that the project is not economic. For the most part the more risks that a particular segment or commercial structure takes on, the higher the returns expected by its investors. For example, if a buyer of LNG or gas must agree to a Take-or-Pay arrangement it takes on more risk than if it did not. Also, if a commercial structure includes taking on price and volume risk in addition to purely operational and completion risk, the investors in that type of arrangement would expect a higher return.

[5] All economics are expressed in unleveraged terms (excluding financing) with the exception of the regas unit when it is leased.

Figure 3 – Breakdown of summary tables

Click to ungroup

17	Consolidated												
18		NPV[1] ($MM)		IRR[1] (%)		CAPEX[2] ($MM)		OPEX[2] ($MM/yr)		Net Cashflow ($MM)		Taxes Paid[3] ($MM)	
19	Project	1,339.4		11.0%		3,677.8		279.5		9,493.2		3,147.3	
20	Model	Private	Gov	Private	Gov	Private	Gov	Private	Gov	Private	Gov	Private	Gov
21	1	128.3	1,211.1	10.1%	11.2%	0.0	3,677.8	130.9	148.5	201.6	9,291.6	47.1	3,100.2
22	2	113.6	1,229.1	9.8%	11.2%	0.0	3,677.8	136.0	143.5	157.4	9,348.9	59.3	3,075.0
23	3	192.6	1,150.1	10.1%	11.2%	321.1	3,356.7	158.1	121.4	845.5	8,660.8	286.1	2,848.1
24	4	1,342.7	NA	11.0%	NA	3,677.8	NA	279.5	NA	9,506.3	NA	3,134.2	NA
25	[1]Unleaveraged, [2]Incl. FSRU capital cost to CAPEX, otherwise FSRU lease cost to OPEX, [3]Excl. Taxes paid by Power Plants when "No" Gov. Utility												
26													
27	Regas												
36	Pipeline												
45	Power Plant												
46		NPV ($MM)		IRR (%)		CAPEX ($MM)		OPEX ($MM/yr)		Net Cashflow ($MM)		Taxes Paid[3] ($MM)	
47	Project	1,150.1		11.2%		3,356.7		121.4		8,660.8		2,848.1	
48	Model	Private	Gov	Private	Gov	Private	Gov	Private	Gov	Private	Gov	Private	Gov
49	1	0.0	1,150.1	NA	11.2%	0.0	3,356.7	0.0	121.4	0.0	8,660.8	0.0	2,848.1
50	2	0.0	1,150.1	NA	11.2%	0.0	3,356.7	0.0	121.4	0.0	8,660.8	0.0	2,848.1
51	3	0.0	1,150.1	NA	11.2%	0.0	3,356.7	0.0	121.4	0.0	8,660.8	0.0	2,848.1
52	4	1,150.1	NA	11.2%	NA	3,356.7	NA	121.4	NA	8,660.8	NA	2,848.1	NA
53	[3]Excl. Taxes paid by Power Plants when "No" Gov. Utility												

• **Interest born by the government utility:** given that one of the primary model choice considerations will be the utility's ability and interest to take on one or several components of the LNG-to-power components, the 'Dashboard' separates out the financing component for the utility. The figure copied out below shows the financing cost that the utility would incur under the various models with the debt structure assumptions shown to the left of the table. The financing costs for the utility should follow a similar pattern as the capital cost results for the government in the consolidated table. The graphic on the right of the table below shows the total payments required to pay off the debt. The way that this figure should be interpreted in our example is that if the government would choose model 1, it would have to take on the capital investment of $3.68 billion (see consolidated table above). If the utility were to finance this capital investment from 70% debt, it would have to have to set aside equity worth $1.1 billion (30% of total capex) and would then have to pay back the principal of $2.57 billion (70% of total capex) plus the financing cost of $1.172 billion (see below in Figure 4).

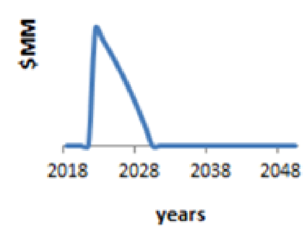
Figure 4 – Financial costs for government utility

Interest Costs borne by the Gov Utility:

Debt structure:

Debt to (Debt+Equity) Ratio	70%
Debt maturity in years	8
Debt interest	8%

Model	$MM
1	1,171.9
2	1,171.9
3	1,074.7
4	0.0



• **Checking the impact of incentives:** Accelerated depreciation, tax holidays or tax deductions can be used to improve the project economics. To test these incentives, users can change tax assumptions in lines 102-112 in the ‘Inputs’ worksheet. For example, if the user wants to test accelerated depreciation incentive, he/she can reduce the depreciation life of assets in cell C103. For a corporate tax deduction or holiday, users can change income taxes in cell C104 and 105.

c. 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 or power prices fall. If it is the case, there will likely be pressures for the contract to be renegotiated.

Project/infrastructure

- **Design capacity**

  - *Impact of oversizing the regasification plant:* This may occur due to unrealistic demand forecasts. Users can test the economic impact by increasing the capital cost and gas output of the regasification unit and/or decreasing the volume taken by Power Plant. Users must not forget to adjust minimum throughput obligations to comply with new assumptions.

- **Construction/ complementary infrastructure**

  - *Impact of construction delays or cost overruns:* delays can be tested by changing the LNG import starting date (‘Inputs’ cell C19). The impact of a lack of complementary infrastructure (e.g. port facilities, pipeline, transmission lines) can be tested in the same way as this will delay the start of operations.

    Cost overruns can be analyzed by changing capital costs of Regasification unit (change cost overrun index - ‘Inputs’ cell C47), Pipeline (change cost overrun index - ‘Inputs’ cell C58) or Power Plant (change capital cost ratio - ‘Inputs’ cell C61).

Operational

- **Operational schedules**

  - *Impact of changes in operations:* users can estimate impacts from more frequent or higher impact maintenance schedules by increasing the figures in line 23 or lowering the percentage in cells C29 in the ‘Inputs’ worksheet. In turn, to test changes in the Power Plant’s operation (for instance, due an increase of renewables dispatch and then a decrease in thermal generation) users must change its capacity factor (cell C30), which represents the power actually generated over the maximum that the power plant can generate.

Commercial/Market

• Volumetric commitments

In a scenario where the Power Plant is not able to take the minimum obligation volumes due to plant operability issues or insufficient customer demand, the model will estimate that:

i. Regas Plant (in the tolling case) – Receives Reservation Fee on shortfall from the Power Plant under the Tolling model option.
ii. Gas Pipeline – Receives no Reservation Fee on shortfall since in all cases it is assumed to make its profits from trading not from acting as a pipeline transporter for a fee.
iii. LNG Buyer – is paid Take-or-Pay amount by Power Plant, but usually must turn around and pay similar amount to LNG Seller under their own Take-or-Pay agreement.

The net effect on entities considered in fiscal model:

i. Merchant or Integrated Option: None for Regas Plant since TOP from Power Plant is assumed to equal TOP to LNG Seller.
ii. In the tolling option the Power Plant will pay reservation fee to Regas owner, and will also process less volumes on which to earn a margin.
iii. Gas pipeline: None, other than fewer volumes of natural gas to trade.
iv. Power plant: Pays TOP amount due for shortfall, or pays Regas owner reservation fee (if tolling).

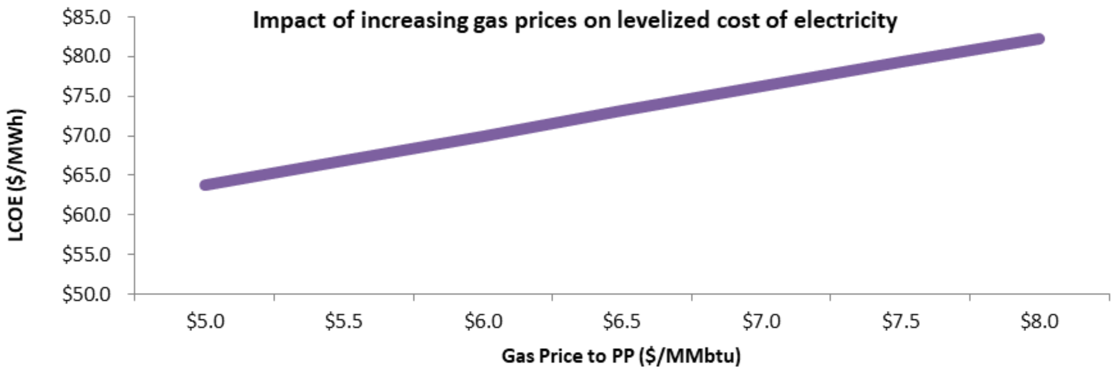
NOTE: Some of these impacts on the Power Plant might be offset if under the Merchant, Partially and Fully integrated options there are other industrial customers who could take the extra supplies of gas when the Power Plant takes less than the required minimum.

- *Shut down effect*: to test shut down effects due to technical problems or changes in market conditions, users can decrease the % of gas taken by Power Plant ('Inputs' cell C27) to see what happens in the project economics. Notice that if the percentage decrease is large enough, TOP effect and some OPEX savings (as it correlates with gas volumes) might occur as complementary effects.

• Gas Prices

- *Impact of increasing gas prices on levelized cost of electricity (LCOE)*: this table presents how gas prices can influence the level of competitiveness of the gas-powered power plant. Countries have different levels of electricity prices, depending on their power generating portfolio. Therefore, as the LCOE is a measure of price level that makes the power plant viable (*break-even*), it reflects if the power plant is a feasible option. The discount rate assumption is 7.5% and it can be modified in 'Inputs' cell120.

Graph 4 – Impact of increasing gas prices on LCOE



- **Electricity Sales**

▪ *Impact of exchange rates*: there is a risk of price volatility due to exchange rate fluctuation. This risk is very common in developing countries. LNG is commonly denominated in American dollars, while electricity in local currency. To test such risk, users can emulate currency volatility/shocks or devaluation over time, by changing power prices in 'Inputs' line 13 and checking the impact in the summary tables in 'Dashboard'. As an example, supposing that Power Plant takes all the risk, if we test a 1% consistent devaluation each year, other things being equal, from a baseline project IRR of 11%, the project would present a 6.8% IRR (where Power Plant go from an IRR of 11.5% to 5.6%).

Table 7 - Summary table: Baseline – Flat Power Prices ($85/MWh)

Consolidated												
	NPV[1] ($MM)		IRR[1] (%)		CAPEX[2] ($MM)		OPEX[2] ($MM/yr)		Net Cashflow ($MM)		Taxes Paid[3] ($MM)	
Project	**1,339.4**		**11.0%**		**3,677.8**		**279.5**		**9,493.2**		**3,147.3**	
Model	Private	Gov	Private	Gov	Private	Gov	Private	Gov	Private	Gov	Private	Gov
1	*128.3*	*1,211.1*	*10.1%*	*11.2%*	*0.0*	*3,677.8*	*130.9*	*148.5*	*201.6*	*9,291.6*	*47.1*	*3,100.2*
2	*113.6*	*1,229.1*	*9.8%*	*11.2%*	*0.0*	*3,677.8*	*136.0*	*143.5*	*157.4*	*9,348.9*	*59.3*	*3,075.0*
3	*192.6*	*1,150.1*	*10.1%*	*11.2%*	*321.1*	*3,356.7*	*158.1*	*121.4*	*845.5*	*8,660.8*	*286.1*	*2,848.1*
4	*1,342.7*	*0.0*	*11.0%*	*N.A.*	*3,677.8*	*0.0*	*279.5*	*0.0*	*9,506.3*	*0.0*	*3,134.2*	*0.0*

Table 8 - Summary table: Decreasing Power Prices (1% per year)

Consolidated												
	NPV[1] ($MM)		IRR[1] (%)		CAPEX[2] ($MM)		OPEX[2] ($MM/yr)		Net Cashflow ($MM)		Taxes Paid[3] ($MM)	
Project	**-191.0**		**6.8%**		**3,677.8**		**279.5**		**2,974.7**		**1,013.3**	
Model	Private	Gov	Private	Gov	Private	Gov	Private	Gov	Private	Gov	Private	Gov
1	*128.3*	*(319.3)*	*10.1%*	*6.1%*	*0.0*	*3,677.8*	*130.9*	*148.5*	*201.6*	*2,773.0*	*47.1*	*966.2*
2	*113.6*	*(301.3)*	*9.8%*	*6.2%*	*0.0*	*3,677.8*	*136.0*	*143.5*	*157.4*	*2,830.4*	*59.3*	*941.0*
3	*192.6*	*(380.3)*	*10.1%*	*5.6%*	*321.1*	*3,356.7*	*158.1*	*121.4*	*845.5*	*2,142.2*	*286.1*	*714.1*
4	*(187.8)*	*0.0*	*6.8%*	*N.A.*	*3,677.8*	*0.0*	*279.5*	*0.0*	*2,987.8*	*0.0*	*1,000.2*	*0.0*

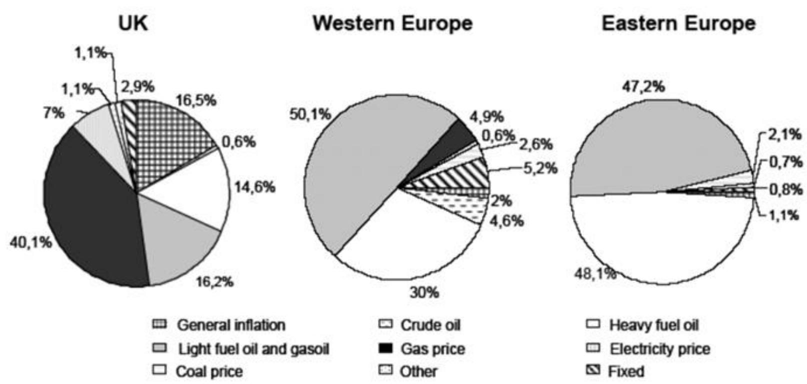
4. Assumptions and input variables

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:

LNG and Gas prices: They are typically agreed with individual buyers under a contract formula. These formulas 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), petroleum products (e.g. heating oil), to a lesser extent other energy products (e.g. coal, power) and inflation indexes (see Graph 3). 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.

Graph 5 – LNG contracts indexation at different places in Europe



Source: Energy Sector Inquiry 2005/2006[6]

LNG prices are usually set on a DES basis 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.[7]

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

[6] European Commission, "DG competition report on energy sector inquiry," Competition DG, (January 2017), available at: http://ec.europa.eu/competition/sectors/energy/2005_inquiry/full_report_part1.pdf

[7] In some cases, FOB prices are quoted where the buyer charters LNG tankers as a means of taking advantage of the spot market prices.

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 (NBP), 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. For the spot market developments, the World Bank commodity price projections can be a good source of reference. However, a range of price sensitivities need to be tested given that projections most likely will not be fulfilled.

Power prices: The setting of power prices is very country specific.

Traditionally, vertically integrated monopolies (from generation to distribution) set tariffs to remunerate the utilities' asset portfolio while providing price stability and affordability to consumers. Tariffs for end-users vary depending on the customer profile, the commercial practices, and often policy objectives. As electricity is viewed as a basic good, governments often subsidize tariffs.

In liberalized and unbundled energy markets power is set through a spot price or by long term purchasing power agreements. At the spot market, price formation occurs when sellers (generators) bid their marginal costs and buyers (utilities, big consumers, traders) present their willingness to buy power. The market sets the price for that moment (often hourly). This process can occur one day before (day ahead markets) or instantaneously.

A useful indicator to assess and compare costs from different power sources is the levelized cost of electricity (LCOE).

Production forecasts - The user will have to adapt the purchase and regasification of LNG volumes to the demand from the power plant guaranteeing a forecast level of power generation. Small product loss due to evaporation and running machinery needs to be taken into account when inputting production figures.

Capital costs forecasts - Since capital costs occur in the very beginning of a project, they have a much greater impact on discounted value indicators. Several studies indicate that companies tend to underestimate the capital costs on megaprojects and therefore sensitivity analyses need to be undertaken on these inputs.

Fiscal terms and taxes - this information should be available from published petroleum and tax laws of the country, plus any agreements, between the government and the regasification investors. Oftentimes, the details of the fiscal terms are not agreed to until right before the Final Investment Decision (FID) 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 volumes, regasification and pipeline capacity are typically measured in units of volume, such as Thousands of Standard Cubic Feet (MCF) or Thousands of Cubic Meters (MCM).
2. LNG Regas Plant capacity is commonly measured in units of weight, typically in Millions of Metric Tons (MT) since they are converting liquid to a gas form.
3. LNG Tanker capacity often is often stated in Cubic Meters (CM), a measurement of size.
4. In many cases capacity is measured as an amount PER DAY while in other situations volumes are referred to as an amount PER ANNUM.
5. For energy consumption the gas may be measured or referenced in units relating to its energy content, typically Millions of British Thermal Units (MMBTU)**.**
6. 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 MMBtu.
7. Electricity prices are commonly set at local currency per unit of electricity such as Megawatt-hours (MWh). In this model, all monetary units are set in U.S. Dollars, but users can assess currency risk by changing relative prices (LNG or power prices) as explained above.
8. 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.

Conversion factors can be found in the Annex (Tables 8 and 9).

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.

Asking the right questions about the assumptions

Commercial Assumptions

- Is a constant DES LNG import price of $6 per MMBtu 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, margins or other input assumptions?
- Is an assumed domestic power price of $85 per MWh consistent with other terms and assumptions?

- Is the gas price sold to the power plants ($7.5 per MMBtu) enough to remunerate the backward value chain (pipeline and regasification)?
- Do the regasification tolls (operating and minimum throughput) compensate the costs to operate under different conditions?
- Are the costs of the regasification unit realistic? What are the advantages of chartering it vs. capital expenditure?

Technical Assumptions

- Is there sufficient gas demand from the power plants to purchase the quantity of natural gas? Is this demand stable over time? Is there enough transport capacity through the pipelines to deliver the gas to the power plants?
- Are investors and the government relying too much on the hope that additional reserves will be discovered in the future?

Total capital costs are estimated at $3.6 billion, with over 90% being made up from the power plant.

- Are estimated capital costs too high/low? Demand forecast plays a crucial role in determining the installed capacity of power plants. Their efficiency (heat rate) and capacity factors defines the amount of gas required, allowing the sizing of the pipeline and regasification unit to be leased.
- Have the appropriate range of sensitivity analyses been run and evaluated?

5. What the model does not include

1. **Technical Input Data** - The model does not create forecasts of 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. **Decommissioning Costs** - Decommissioning costs are not considered in this model, but can be relevant for the end of life of the pipeline, power plants and the regasification unit when the FSRU is acquired.
3. **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 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

Annex

Table 9 – List of references for parameters used in the model

SEGMENT	Type	Parameter	Range
REGAS	SIZE	FSRU capacity	1.7 – 8.3 mtpa (send out)
	CAPEX	FSRU cost (new build)	295-450 $MM
		FSRU cost (converted vessel)	~200-270 $MM
	TIME	FSRU construction (new build)	27-36 months
		FSRU conversion (converted vessel)	18 months
	OPEX	FSRU annual operating expenses	1-3% of CAPEX or $ 20k-45k or 0.5 $/MMBtu
	OPEX	FSRU leasing	$110k-160k (dayrate)
	TECHNICAL	FSRU gas consumption	1.5-2.5%
POWER PLANT	SIZE	CCGT installed capacity (per unit)	60-430 MW
	CAPEX	CCGT overnight cost*	596-1687 $/kW
	TIME	CCGT construction	24-30 months
	OPEX	CCGT fixed O&M	11.1-48.1 $/kW
		CCGT variable O&M	0.2-4.3 $/MWh
	TECHNICAL	CCGT Heat Rate	6,300-7,700 Btu/kWh
	TECHNICAL	CCGT capacity factor	35%-93%

*Overnight cost - includes pre-construction (owner's), construction (engineering, procurement and construction) and contingency costs, but not interest during construction.

Source: OIES (Brian Songhurst), 2017; USAID (2013); IEA (2015); US EIA (2018); IEA-ETSAP (2010)

Table 10: General Conversion Factors for Energy

To: From:	TJ	Gcal	Mtoe	MBtu	GWh
TJ	**1**	**238.8**	**2.388×10^5**	**947.8**	**0.278**
Gcal	**4.187×10^3**	**1**	**10^{-7}**	**3.968**	**1.163×10^3**
Mtoe	**4.187×10^{-4}**	**10^7**	**1**	**3.968×10^7**	**11,630**
MBtu	**1.055×10^3**	**0.252**	**2.52×10^{-8}**	**1**	**2.931×10^4**
GWh	**3.6**	**859.8**	**8.6×10^{-5}**	**3,412**	**1**

Source: IEA

Table 11: Additional Useful Conversion Factors

1SCM (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[8]

[8] Gail (India) Limited, "Natural Gas," available at: http://www.gailonline.com/BV-NarutalGas.html, (last accessed November 2018).

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