Report

FLNG Tariff Analysis

to

Enemalta

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IPA
Energy + Water Economics

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to

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3. INTRODUCTION

Enemalta Corporation (“Enemalta” or “the Client”) hired IPA Energy + Water Economics (“IPA”) to undertake a study on the “Optimisation of Investment Options in Power Generation in Malta”. Whilst this study was undertaken, Enemalta requested that the scope of the study be extended to provide a Tariff Analysis of a Liquefied Natural Gas Floating Storage and Regasification Unit located 12 kilometres off the Maltese coast (“LNG FSRU”).

This paper sets out the analysis IPA has undertaken on the likely tariff that would be charged for gas via an LNG FSRU located 12km from the Maltese coast. The rest of this paper is set out in as follows.

Section 4 sets out LNG price projections;

Section 5 sets out the costs associated with shipping LNG approximately 1000miles;

Section 6 sets out expected regasification and storage costs;

Section 7 sets out the tariff associated with a 12km marine gas pipeline for the FLNG; and

Section 8 presents a summary of the analysis.

4. LIQUID NATURAL GAS PRICE PROJECTIONS

In the last couple of years the spot price of Liquid Natural Gas (LNG) has fallen significantly due to three main factors, namely:

- the world-wide economic recession;
- the discovery of a cost effective way to extract shale gas; and,
- the considerable increase in the supply of LNG that has come on stream.

The world-wide economic recession led to a significant reduction in the demand for gas, especially in the industrial and power sectors of Europe and North America. The discovery of how to extract shale gas in a cost-effective manner has changed the outlook regarding the potential volume of gas that could be produced globally, and especially in the USA and China The implication is that gas is no longer perceived as rare a commodity as it was thought a few years ago. In parallel the demand for LNG in the US has shrunk significantly. On the other hand, the increase in the supply of LNG that has come on stream is the result of numerous LNG projects that have been in production for years reaching completion over the last year.

Going forward, these factors will all play a role in determining future gas prices. While in the past, gas prices have been closely linked to oil prices, these recent developments in the gas market have resulted in unprecedented differences between spot market gas prices and long term oil linked contract prices for gas. This has led many buyers with long term contracts to ask for a decoupling of the gas and oil price.

Historically, gas prices were linked to oil prices because gas markets were generally not liquid enough to generate efficient pricing and since oil was seen as a substitute for gas and that gas was often produced as a by- product of the oil industry (associated gas), gas prices became indexed to the price of oil.

More recently however, the development of an increasingly global LNG market has started revealing the potential for increased competition and liquidity within the gas market and spot and long term gas prices that are determined by global demand and supply conditions rather than by oil-indexation. Europe in particular is increasingly becoming more dependent on LNG to meet its gas demand and therefore will increasingly be affected by global demand and supply for LNG in a way it has not been up until now.

While the gas price determined in regimes driven by market fundamentals would still be expected to correlate strongly with the oil price, the fact that increasing volumes of non-associated gas could be produced and transported globally should imply that significant and sustained deviations will be possible

Taking this into account, we have considered two broad LNG price scenarios:

- LNG contract prices **remain indexed to the oil price**, with LNG price projections based on crude oil price projections; and,
- LNG contract prices are **decoupled from oil prices** and instead are determined by international gas price projections and the relative global demand and supply of gas.

In the scenarios where LNG contract price remain indexed to oil prices, we look at three oil price projections: high, expected, low. In the scenarios where LNG contract prices are decoupled from oil prices, we look at price projections if the gas market remains loose and price projections if the global gas market tightens.

4.1. LNG price projections based on oil price projections

IPA's PowerView projections for Gasoil, HFO and Oil were used in the following formula to determine oil-indexed gas price projections:

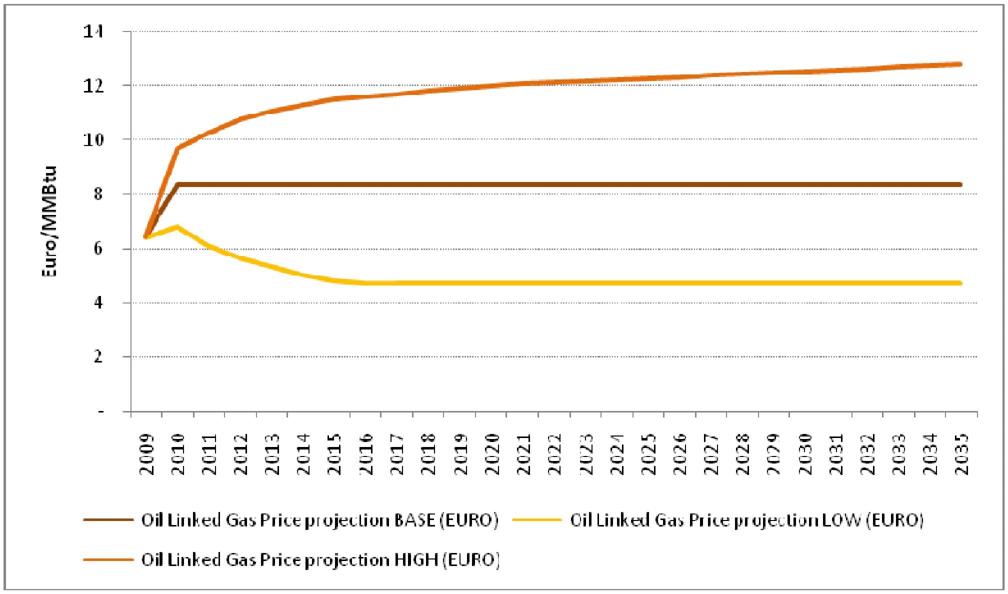
$$Pgas(\$/MMBtu) = \$9 * 0.5 * \left(\frac{CurrentGasoil\,Price(\$/t)}{Gasoil\,Reference\,Price(\$/t)} \right) + 0.3 * \frac{CurrentHFO\,Price(\$/t)}{HFO\,Reference\,Price(\$/t)} + 0.2 * \frac{CurrentOil\,Price(\$/bbl)}{ReferenceOil\,Price(\$/bbl)}$$

This formula was actually used by one of the bidders in 2008 to supply gas for Enemalta. It adopts a fairly common pricing principle, based on an initial price level determined in the beginning of the contract and adjusted by the (weighted) changes in prices of liquid fuels within the period considered, with respect to their value at the beginning of the contract. The references prices used in the formula were the delivered fuel prices in 2009 that Enemalta provided to IPA. The current prices were IPA's PowerView projections that were calibrated based on the delivered fuel prices provided to IPA. A flat rate of 1.4 € / $ exchange rate was assumed to convert the gas price to € / MMBtu terms.

Three different crude oil price cases were considered for scenario analysis: the base case where crude oil is priced at $80 a barrel; a low case scenario where oil is priced at $65 per barrel falling to $45 per barrel; and a high scenario where oil is priced at $92.50 rising to $122.50 a barrel. All these price projections are inclusive of insurance and freight costs and are in 2010 prices[1].

Exhibit 1. Gas Price Projections based on oil linked formula (Euro/MMBtu)

[1] For the purposes of this pricing study, we did not consider volume restrictions on the imported gas, such as Take-or-Pay constraints. In a contractual setting, there may be such constraints, but we do not think it is appropriate to include them in pricing scenarios, since volume constraints will be specific to each supplier and could vary significantly across suppliers.



Source: IPA

4.2. LNG price projections decoupled from oil prices

Over 2010-2012 it is estimated that there will be approximately 100 bcm of uncommitted LNG produced. If global demand for gas does not increase to meet this supply, such an uncommitted volume of gas will put significant downward pressure on spot gas prices and will increase pressure for gas prices to be decoupled from oil prices.

Under such a scenario, it would be expected that LNG prices would tend towards the generally lower global price for gas, the US Henry Hub gas price. This could be viewed as a "lower bound" LNG price Free on Board (FOB) projection. PowerView projects the gas price at the Henry Hub to be around $5.35/MMBtu (€3.82/MMBtu) when crude prices are $80/bbl.

In contrast, if global gas market conditions tighten, the LNG price could actually increase above an oil indexed gas price, if the oil market doesn't face the same market conditions.

There are a number of factors that could result in such a tightening of the gas market. Firstly, a surge in demand for gas could end up consuming all the surplus gas. While such a surge in demand is not very likely in Europe due to the relative maturity of the existing markets and the long-run effects of the recession, it is likely in Asia. In particular, gas demand growth in China and India is potentially huge and the currently depressed prices of gas could attract new buyers to the market. On the supply side, the expected surge in LNG supply might just not happen because of technical or political problems. Similarly, LNG producing countries may elect to consume more of their gas domestically rather than exporting it while the production of shale gas may not be as extensive as thought, resulting in higher demand for LNG in the US.

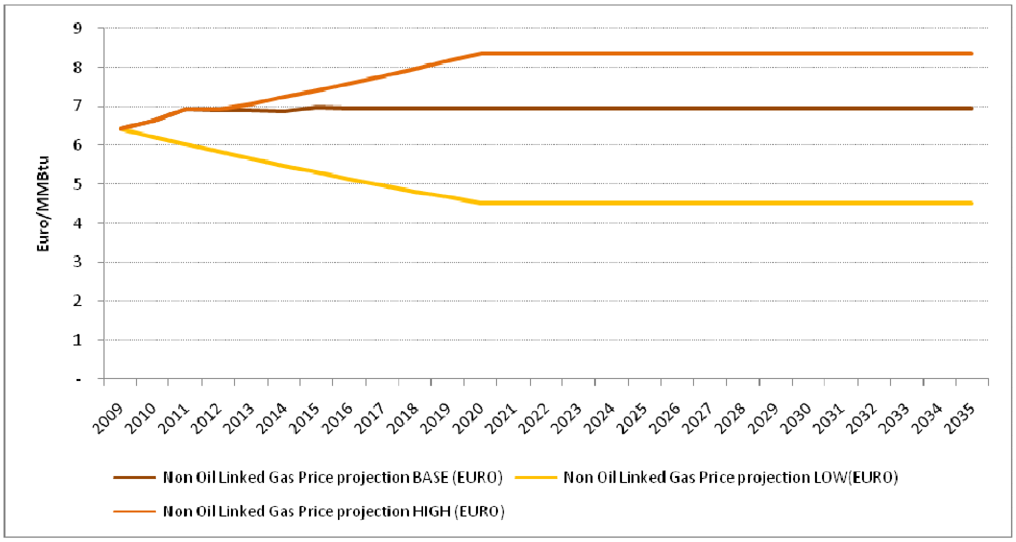
With Europe's increased reliance on LNG supplies, in a tight market European LNG buyers will have to compete against Asian LNG buyers who traditionally are willing to pay a premium of between 20-30% over European buyers for their gas supplies[2]. Therefore, it would be

[2] There are a number of reasons why the Japanese have usually paid a higher price for their supplies. The first is that they do not have access to any other source of natural gas; they are completely dependent on LNG imports unlike most buyers in Europe who can access piped natural gas at lower costs. The second reason is that their prices are indexed to Japanese Oil prices (Japanese Crude Cocktail) which are generally higher than European oil prices. The third reason is the higher cost of shipping to relatively remote areas while the fourth

reasonable to expect LNG prices to rise to levels projected in Japan, as an upper bound[3] in tight gas market conditions.

The following chart sets out some LNG price projections that move away from those implied by oil-linked formulas. The higher price projection is based on the European gas price increasing towards a Japanese price level by 2020, which was assumed to be 20% higher than PowerView's European BAFA power price projection[4]. The base projection is PowerView's European BAFA power price projection. The low projection is based on the European gas price heading towards the PowerView's Henry Hub gas price projection plus freight and insurance costs of $1/MMBtu by 2020. All of these gas price projections include insurance and freight and are in 2010 prices.

Exhibit 2. Gas Price Projections (Euro/MMBtu)



Source: IPA

reason is that security of supply has often been more important to traditional Asian LNG buyers (Japan, Korea, Taiwan) than price with the result that they were willing to pay a considerable security of supply premium.

[3] Note, in contrast to the traditional Asian LNG buyers, the Chinese and Indians, are considerably more sensitive to gas prices. As a result, if it is Chinese and Indian demand that leads to a tightening of market conditions it does not seem likely that they would be as willing to pay such high prices as the traditional Asian LNG buyers, exerting downward pressure on the global market prices.

[4] Over the last ten years the Japanese LNG price has been 20% higher than the European price (since 1984 the average difference was 30%).

5. LNG SHIPPING COSTS

Enemalta asked IPA to investigate the LNG shipping costs associated with a 1000-mile journey. Tankers typically travel at 20 to 29 miles per hour (17 to 25 knots per hour), implying that they can travel between 470 and 690 miles a day. It takes approximately one day to load and another day to unload the tankers[5]. Thus the time it would be expected to take a tanker to transport 150,000 cubic metres 2000 miles (1000 mile round trip) would be 8 days - 4 days travelling, 2 days loading and unloading and 2 days contingency for the weather.

The cost of shipping LNG has fallen significantly in recent years. In September 2010, carrier day rates in the Atlantic were around $44,000 a day[6], down from around $75,000 in the winter months of 2007[7] but up from March 2010 when they were around $35,000. In our estimate of shipping costs, we assumed a daily carrier rate of between $35,000 and $75,000 a day for a ship with a capacity to carry 150,000 cubic metres (64,000 metric tonnes) of LNG. Such carrier day rates, resulted in carrier costs for a round trip taking 8 days of between $0.08 (€0.06) and $0.11 (€0.08) per MMBtu.

In addition to the carrier costs, the transport of LNG by ship is also subject to boil-off costs. These costs were assumed to range from 0.1% to 0.25% of the ships capacity per day. Such boil-off rates imply that between 26,820 and 67,051 MMBtu of the LNG cargo are lost during the voyage. Taking the base oil linked gas price projection described in the previous section (where the gas price is $11.73/MMBtu), this implies a boil off cost of between $0.09 (€0.07) and $0.25 (€0.17) per MMBtu of LNG transported by ship.

The final component of the shipping cost will be the fuel cost. It was assumed that this would cost approximately $0.01 per MMBtu per day, or $0.10 (€0.07) per MMBtu per 8 day voyage[8]. The following table summarises all these shipping cost estimates which are in 2010 prices. It is assumed that these shipping costs will remain constant in real terms over time.

Exhibit 3. Shipping Cost Estimates

Shipping Cost Component	Lower Estimate	Higher Estimate	Lower Estimate	Higher Estimate
	Dollar ($)		Euro (€)	
Carrier Cost Total	$35,000	$45,000	€25,000	€53,500
Carrier Cost per MMBtu	$0.08	$0.11	€0.06	€0.08
Boil Off Percentage	0.1%	0.25%	0.1%	0.29%
Boil Off Cost per MMBtu	$0.09	$0.23	€0.07	€0.17
Fuel Cost of Voyage per MMBtu	$0.10	$0.10	€0.07	€0.07

[5] (http://www.morantug.com/lngactivities.asp) and http://www.cheresources.com/lng_terminals.pdf

[6] Platts LNG Daily September 1, 2010.
[7] According to Navin Thakur, an analyst at London-based Drewry Shipping Consultant Ltd. www.businessweek.com

[8] This was based on shipping fuel costs set out in Platts LNG Daily September 1, 2010.

Total Shipping Cost per MMBtu	**$0.27**	**$0.44**	**€0.19**	**€0.31**

Source: IPA

Assuming a Regasification rate of 2000 metric tonnes a day, it will take approximately 31.5 days to regasify 150,000 cubic metres (63,000 tonnes), implying that a 150,000 cubic metre LNG tanker would only need to refill the FLNG station once a month.

5.1. Shipping Distance, Time and Cost to and from Major LNG Liquefaction Plants

While the Client requested that we look at the costs associated with a 1000-mile voyage, we note that there are many major liquefaction plants that are more than 4,000 nautical miles away from Malta, which may be of interest in terms of potential sources of supply. The table below shows the approximate distance, time needed and estimated cost to ship LNG between three major LNG exporters and Malta.

Exhibit 4. Shipping Cost to Liquefaction Plants

LNG Exporter	Distance in Nautical Miles	Time needed to complete a round trip		Estimated Cost per MMBtu of LNG Transported	
		@17 Knots per hour	*@25 Knots per hour*	*@17 Knots per hour*	*@25 Knots per hour*
Trinidad and Tobago	4,405	26	19	€1.32	€0.96
Nigeria	4,088	24	18	€1.22	€0.91
Qatar	4,003	24	17	€1.22	€0.86

Source: IPA

The time needed includes the time taken to load and unload the vessel and two days for contingency. The estimated costs per MMBtu were calculated assuming a carrier day rate of $45,000 per day.

6. FLNG REGASIFICATION COSTS

Our estimate on the tariff that will be applied to gas (regasified and stored) on an FRSU was calculated using tariff information from Italy's offshore LNG regasifier operated by Adriatic LNG.

The tariff imposed for regasification at the FSRU is regulated by Italy's Electricity and Gas regulator. It is broken down into four components as follows:

- a commitment charge;
- a berthing charge;
- a regasification charge; and
- a charge in kind.

The commitment charge is currently set at €20,553 per thousand cubic metres of liquefied LNG for LNG imported under long term contracts, and €19,526 per thousand cubic liquid metres of LNG spot cargo. The berthing charge for LNG imported through long term contracts and spot LNG cargo are €369,097 and €498,604 per berth, respectively. The regasification charge per unit of LNG imported under long term contracts is €0.12 per GJ (€0.11/MMBtu) and for spot LNG the charge is €0.16 per GJ (€0.15/MMBtu). The charge in kind, to cover losses incurred during the regasification process is the same for contracted and spot LNG at 1.5% of the total delivered volume.

Based on these tariffs, it is estimated that a 150,000 cubic metre LNG carrier which has an LNG load after shipping losses of 3.3million MMBtu will incur a cost per MMBtu of LNG regasified of €1.18 per if brought in under a long term contract or €1.22 otherwise. The following table provides a breakdown of this cost in 2010 prices. It is assumed these costs remain constant in real terms over time.

Exhibit 5. FLNG Regasification Charges

	Total €000		Per MMBtu €/MMBtu	
	Contract	Spot	Contract	Spot
Commitment Charge	3,083	2,929	0.96	0.91
Berthing Charge	369	499	0.11	0.15
Regasification Charge	366	496	0.11	0.15
Total Cost	**3,818**	**3,924**	**1.18**	**1.22**

Total Volume LNG Regasified	*3,226,241MMBtu*
Volume of LNG lost during regasification	*49,131 MMBtu*

Source: IPA

7. GAS PIPELINE TARIFF

Since the FLNG station will be located 12km off the Maltese coast, a 12km pipeline will need to be built between the FLNG station and the mainland. This section sets out the assumed characteristics of such a pipeline and the estimation of likely tariffs. The technical parameters assumed for this pipeline are set out in the following table.

Exhibit 6. Pipeline Parameters

Pipeline from FLNG to Malta - 12 Km Offshore		
Item	Units	12" Pipeline 20% Contingency
Length	Km	12.0
Outside Diameter	mm	323.9
Wall Thickness	mm	7.9
Specific Gravity		0.65
Inlet Pressure	bar	85
Flow Rate	mmscf/d	99.5
Outlet Pressure	bar	23.5

Source: IPA

The capital costs of laying the pipeline were based on various studies IPA, Penspen and ENI conducted recently for a 90km 12 inch pipeline. The capex cost for the 90km pipeline were estimated to be €189,918[9], so it was assumed that the capex cost for a 12km pipeline will be approximately 13% (12/90) of this (€25,323). The following table sets out how this assumed capex is broken down into various different components.

Exhibit 7. Capital Expenditure (US$000 2008 prices)

Cost Element	12Km 12" Pipeline With 20% Contingency.
Offshore	
Material Procurement - Pipeline	6,968
Construction - Mobilisation/Demob	1,600
Construction - Pipe Lay	9,067
Engineering/Management/Sup.	1,867
Trenching	1,600

[9] Excluding the cost of a Hot Tap.

Contingency	4,220
Total	**25,323**

Source: IPA

It is estimated that construction duration would be approx 3 months. All cost have been phased over the construction period based on the nature of the cost and have also been aggregated by year to provide a discounted cash flow analysis. An estimate has also been made of the proportion of offshore lay costs associated with mobilisation and demobilisation.

Operational expenditure associated with the 12km pipeline was assumed to be 7.8% (12/153) of the operational expenditure assumed with the proposed 153km pipeline described in our previous report[10]. The following chart sets out these assumed operational expenses.

Exhibit 8. Operational Expenses (US$000 2008 prices)

Operating Costs	Annual Cost US$(000)	Total Cost US$(000)
Offshore Survey	196	1,569
Shore Approach	78	627
Intervention Works Std Maintenance	290	2,322
Intervention Works	290	871
Insurance	78	1,647
Tech Assistance	31	659
Others	10	212
Management	63	1,318

Source: IPA

As in our previous report, it was assumed that offshore surveys, shore approaches and standard maintenance would occur every year for the first five years and then every five years after that. Insurance, telecoms license, technical assistance, management and other costs are expected to occur every year, while major intervention works have been assumed to occur only every ten years. All of these costs are expected to occur annually over the assumed 20 years lifetime of the pipeline.

The operating costs have been summarized and phased by operation and calendar year based on the planned frequency of each activity. The calendar year phasing has been used in the discounted cash flow analysis.

A financial analysis was carried out to determine a pipeline daily capacity charge for the various options examined. This charge is expressed as a daily reserved capacity tariff per MMBtu based on a daily capacity of 45,000 MMBtu, which would enable all the daily regasified gas (2000 m^3 per day) to be transported to the mainland.

The analysis is based on 100% equity financing and does not consider any debt funding. The capex estimates have been phased across the 3-month construction period (July 2011 to September 2011). The monthly costs have been aggregated for the fiscal years 2010/2011.

It is assumed that the operational start date is 1 October 2011. Cost estimates for the various activities involved during the project term were developed based on previous studies IPA has conducted. Operating expenses have been compiled for the 20-year operating period based on the planned frequency and occurrence of the various activities. The costs for each year of operation were apportioned to each fiscal year commencing 1 Jan 2011.

[10] Gas Supply Report to Enemalta, October 2009.

Revenue is calculated as reserved capacity times the Base Tariff level which yields a net present value of zero in real terms based on a real discount rate of 6%, after all relevant capital and operational costs and taxes are accounted for. The Base Tariff is calculated in 2008 dollars, converted into euros using an exchange rate of 1.4 US dollars to the euro, and inflated to nominal values using a 2% compound annual inflation assumption.

The EBITDA is calculated for each fiscal year by deducting operating expenses from annual revenues.

Capital allowance relief is calculated based on the declining balance method using a rate of 25%. Tax is calculated at the corporate rate of 35% applied to earnings after depreciation and interest.

Net cash flows are calculated via deducting capital and operational costs as well as taxes from Revenue in each year and converted to real terms taking into account a constant annual inflation rate of 2%. Discounted cash flows are calculated via applying a real 6% discount rate, assuming cash flows occur at the end of each fiscal year. Finally, the Base Tariff is back-calculated by iteration such that the after-tax discounted cash flows sum to zero.

The key parameters used in the evaluation were:

- Discount Rate 6% Real
- Corporate Tax Rate 35%
- Tax Holiday None
- Capital Allowance Relief 25% Declining Balance
- Depreciation Period 20 Years
- Construction Period Jul 2011 - September 2011
- Operations Start Date 1 Oct 2011
- Project Term 20 Years
- Inflation 2% annual compound

This financial analysis indicates that the tariff per unit of pipeline capacity would be approximately **€0.14 ($0.20)** per MMBtu per day.

8. LNG PRICE SUMMARY

Pulling together estimates of shipping, regasification and pipeline costs, it is estimated that the price of gas entering Malta will be expected to be between €1.51 and €1.67 per MMBtu over the Free on Board ("FOB") price of LNG located 1000miles from Malta. The following table summarises this cost breakdown.

Exhibit 9. Summary of 1000mile Shipping, Regasification and Pipeline costs

Cost Component	Euro Per MMBtu
Shipping Cost (1000 mile)	€0.19 - €0.31
Regasification Costs at FSRU	€1.18 -€1.22
Pipeline tariff (12km)	€0.14
Margin over the FOB LNG Price	**€1.51 - €1.67**

Source: IPA

Shipping costs associated with shipping LNG from Liquefaction plants in Trinidad and Tobago, Nigeria and Qatar would be expected to be significantly higher between €0.86 and €1.32 per MMBtu. With such shipping costs the margin over FOB prices that would be required to import LNG from these countries would be between €2.18 and €2.68.

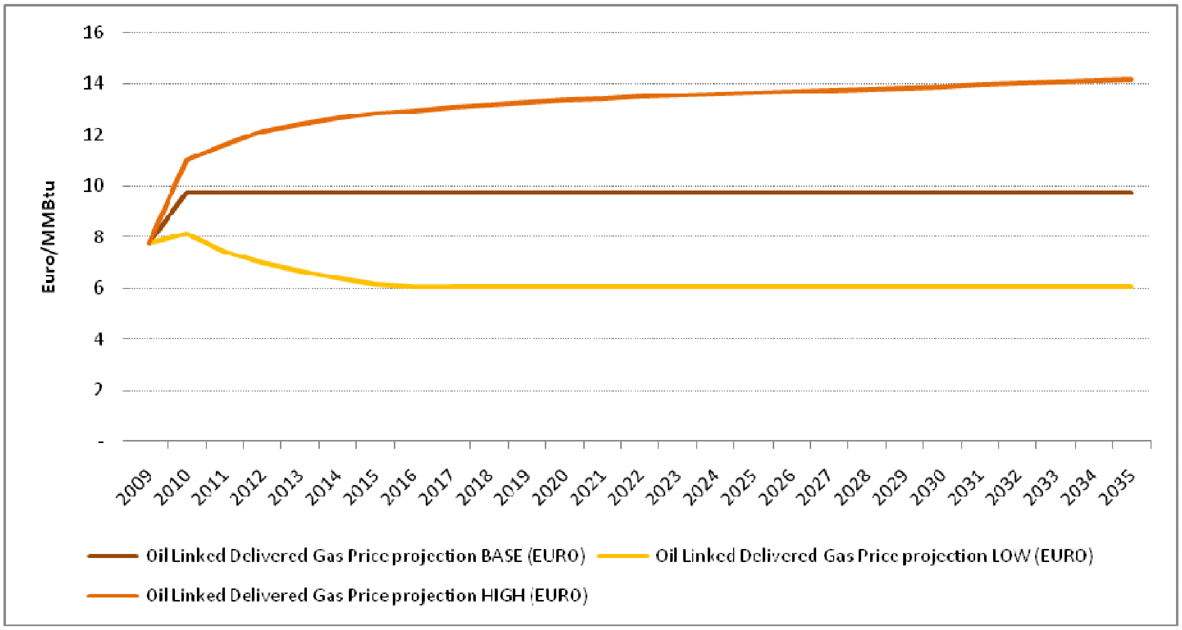
Exhibit 10. Summary of Shipping, Regasification and Pipeline costs

Cost Component	Euro Per MMBtu
Shipping Cost (4000miles+)	€0.86 - €1.32
Regasification Costs at FSRU	€1.18 -€1.22
Pipeline tariff (12km)	€0.14
Margin over the FOB LNG Price	**€2.18 -€2.68**

Source: IPA

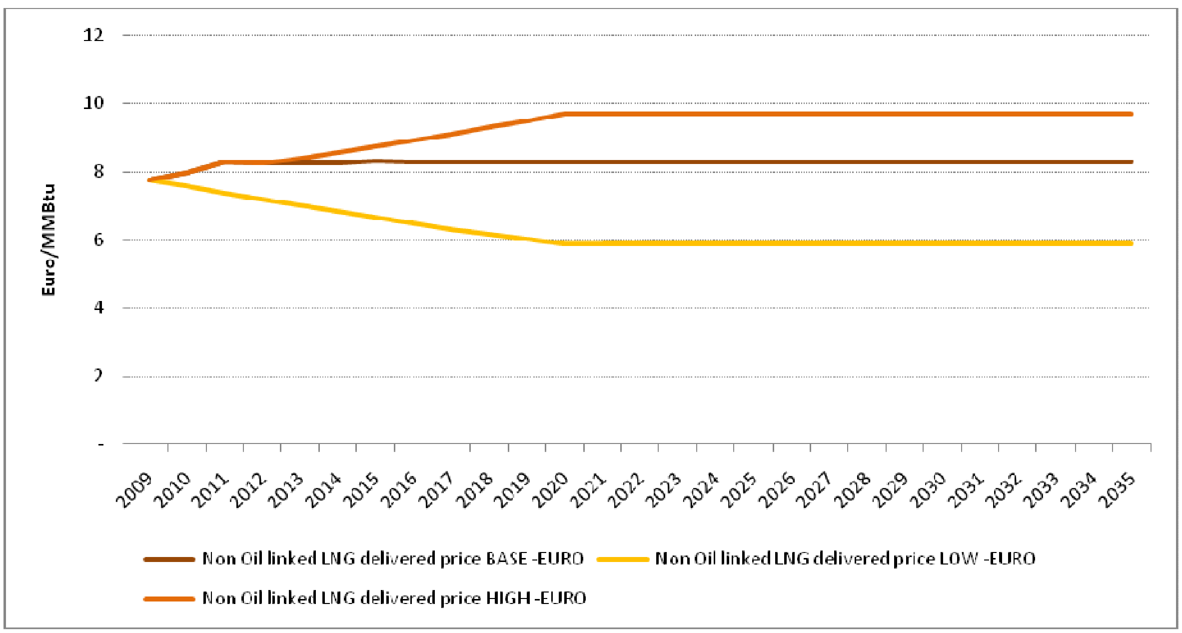
Taking the gas price projections set out in section four and adding on the average cost of regasification (€1.20) and the pipeline tariff (€0.14) we get the delivered gas price projections for Malta. These projection are shown overleaf, the projection in the first chart are those based on the oil price formulas while the projections in the second chart are based on the PowerView's gas price projections as described in previous sections.

Exhibit 11. Oil-linked delivered gas price projections



Source: IPA

Exhibit 12. Non Oil-linked delivered gas price projections



Source: IPA