Report

MPC IPO Market Advisory

to

Musandam Power Company SAOC

12 June 2018

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Table 1: Abbreviations and Acronyms	
Abbreviation	**Definition**
CAGR	Compound Annual Growth Rate
CCGT	Combined Cycle Gas Turbine
COD	Commercial Operation Date
EBITDA	Earnings Before Interest, Tax, Depreciation and Amortisation
ECLIPSE™	*Emissions, Constraints and Legislation Interactions in Power System Economics*
EFOR	Effective Forced Outage Rate
EPC	Engineering, Procurement and Construction
ERH	Engine Running Hour
GDP	Gross Domestic Product
GW	Gigawatt
GWh	Gigawatt Hour
HHV	Higher Heating Value
IC	Internal Combustion
IDC	Interest During Construction
IMF	International Monetary Fund
IPA	IPA Advisory Limited
IPO	Initial Public Offering
IPP	Independent Power Project
kV	Kilovolt
kW	Kilowatt
LHV	Lower Heating Value
LNG	Liquefied Natural Gas
LP	Linear Programming
LRCCR	Levelised Real Capital Charge Rate
LRMC	Long Run Marginal Cost
MMBtu	Million British Thermal Units
MPC	Musandam Power Company
MPS	Musandam Power System
MW	Megawatt
MWh	Megawatt Hour
O&M	Operation and Maintenance
OPWP	Oman Power and Water Procurement Company
PPA	Power Purchase Agreement
PV	Photovoltaic
RAECO	Rural Areas Electricity Company
RE	Reciprocating Engine
SRMC	Short Run Marginal Cost
SYS	*Seven Year Statement*
TIC	Total Investment Cost
TV	Terminal Value
US$	United States Dollar
WACC	Weighted-Average Cost of Capital
WEO	*World Economic Outlook*

1 Introduction

IPA Advisory Limited (IPA) has been engaged by Musandam Power Company SAOC (MPC or the Client) to provide an assessment of the Musandam independent power project (IPP) (the Asset) after the expiry of its power purchase agreement (PPA) with the Oman Power and Water Procurement Company (OPWP) in support of the forthcoming initial public offering (IPO) of MPC.

The Asset is located in the Wilayat Bukha in the Musandam Governorate of Oman and started commercial operations in June 2017. The plant was procured by OPWP in late 2014 as part of a strategy to diversify electricity supply away from more expensive, small diesel-fired units, owned and operated by the Rural Areas Electricity Company (RAECO) which is responsible for electricity supply in the region. The plant, which is fuelled by natural gas with fuel oil as a backup, and was built by Wärtsilä under a turnkey contract, can be expected to have an operational lifetime of 40 years, well beyond the fifteen year term of the PPA. There is thus a potential value opportunity to be captured after the expiry of the contract.

This report provides our outlook for the market and forecast post-PPA value for the Asset. It is structured as follows:

- **Section 2**: explains our approach to post-PPA valuation.
- **Section 3**: summarises the main assumptions used in deriving our base case outlook.
- **Section 4**: presents the outlook for the development of the Musandam Power System (MPS) to 2056.
- **Section 5**: details the expected operation and value of the Musandam IPP in the post-PPA period, 2032-56.
- **Section 6**: provides a summary and conclusions from the analysis undertaken.
- **Annex A**: provides details of ECLIPSE™, our proprietary electricity and desalinated water market modelling platform used to develop the forecasts.

In addition, the complete set of modelling assumptions and results has been provided separately to the Client in spreadsheet format:

- *ECLIPSE Oman MPS - Assumption Book 180607.xlsb*: details all the assumptions used in our market modelling.
- *ECLIPSE Oman MPS - Results Summary 180607.xlsb*: provides full results for the base case and all sensitivities.

Please note that all monetary values are expressed in **real 2018 terms**, unless stated otherwise.

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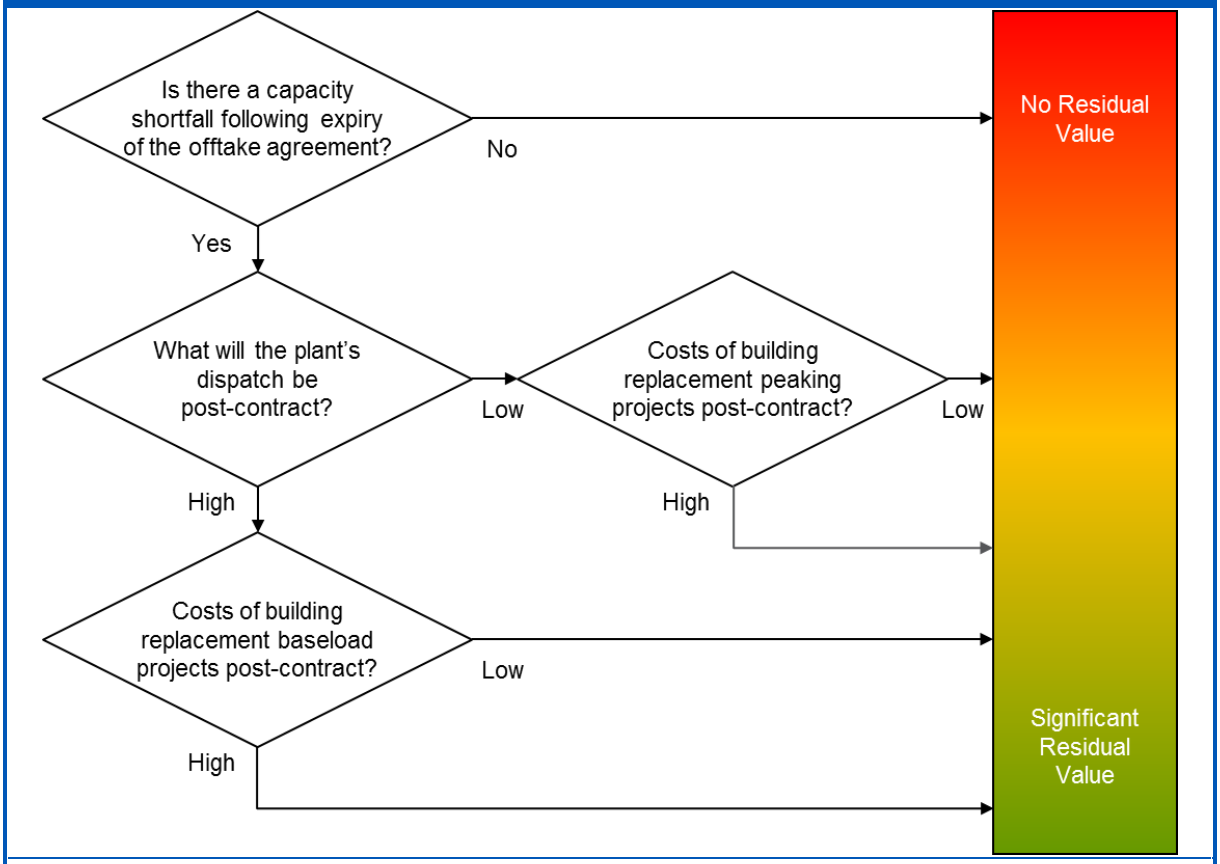
2 Residual Valuation Approach

We use a rational economic approach to assessing the value of an asset after the expiry of any offtake contracts such as power purchase agreements (PPAs). Three key questions need to be considered to determine the value of an asset at the expiry of its offtake agreement, and the answers to them will determine the residual value of the asset in the market, as shown in Figure 1:

Figure 1: Derivation of Post-Contract Value



Source: IPA

1. *Will there be demand for the asset's capacity post-contract?* If there is no demand for the asset's capacity or output when the contract expires, it will have no residual value. Therefore, a sufficiently high level of demand for capacity is a necessary precondition for the asset's value to be positive.
2. *What will be the dispatch profile of the asset post-contract?* Will it operate as a baseload or peaking plant? If there is demand for the asset's capacity or output, the magnitude of its value will be determined by identifying the benefits that the asset can yield, what plants can replicate these benefits, and the net cost of deploying those replacement plants if the asset was closed at the expiry of its offtake agreement. The asset's post-contract dispatch profile will be influenced by the difference in its marginal operating costs relative to those of new replacement and existing plants. If the asset's marginal operating costs are similar to those of new replacement plants (for example, because the thermal efficiency of new entrants is close to that of the asset), the fuel cost savings from switching to the replacement facilities will be lower and this will help strengthen the value of the asset. If on the other hand, new facilities have lower marginal operating costs, they will tend to push the asset towards a peaking role.

3. *What is the cost of building new replacement plants which would have to be deployed to replicate the benefits provided by the asset?* The annual levelised cost of building appropriate new replacement plants will thus play a significant role in determining the residual value of the asset. The higher the costs of building new plants, the higher the value of extending the asset's lifetime, and vice versa.

The modelling approach we use captures all these elements. Importantly it is also independent of the specific market structure under consideration, and can be applied to both liberalised markets and those with a single, central buyer under the premise that in every case, participants will seek to minimise cost.

- *Single Buyer*: In a single buyer market such as Oman currently, an extension to the offtake contract would need to be negotiated. The basis for establishing the annual remuneration for the asset should be the total avoided cost of having to build new replacement plant(s) less any potential operational savings from future technological improvements (e.g. fuel savings from efficiency gains). The single buyer should be willing to accept a contract extension offer that is equally competitive as the most cost-effective alternative.

  For this approach, we therefore assess the market development with and without the asset in question after the expiry of the contract, and compare the total system costs (fuel, operating and maintenance, and capital investment) in each case. The residual value of the asset is the net savings by keeping it open beyond the contract term.

- *Liberalised Market*: In an open market (which OPWP is planning to introduce in the Main Interconnected System of the country from 2021, but not in the MPS), an asset will have to compete against other plants to sell its output and receive the common market price. Prices in any period will be determined by the fuel and operating costs of most expensive unit just needed to meet demand plus the value of capacity required to maintain system stability. The residual value of the asset will thus be the expected revenues from electricity sales and capacity provision, less fuel and operating expenses, after the expiry of the offtake contract.

For the Musandam IPP we have used the single buyer approach as the basis for our residual valuation, as the small scale of the system means that it would not be realistic for a competitive market to be introduced. However we do also calculate the forecast asset liberalised market value as a comparison to the cost savings which the single buyer could achieve to demonstrate the relative equivalence of the approaches.

3 Outlook Assumptions

This section presents the main assumptions behind our base case outlook for the Musandam power system (MPS). We review the forecast demand growth, detail the operational assumptions for existing and new power plants, including the Musandam IPP, and provide a view on the costs of future new builds to meet demand.

3.1 Macroeconomics

The latest International Monetary Fund (IMF) *World Economic Outlook (WEO)* from April 2018 forecasts GDP growth for Oman to average 2.0% annually in real terms between 2017 and 2023. We have assumed this trend will continue to 2030, before slowing slightly to 1.75% *per annum* over the remainder of the forecast. US$ inflation is forecast to average 2.2% over the same period, and we assume it will be 2.0% annually thereafter. The Omani Rial is pegged to the US$ at a constant exchange rate of 0.38502 Rials per dollar.

Table 2 below summarises the macroeconomic assumptions.

Table 2: Macroeconomic Assumptions

	Oman GDP Growth Rate	US$ Inflation
2018	2.08%	2.54%
2019	4.17%	2.44%
2020	2.23%	2.13%
2021	1.82%	2.04%
2022	2.23%	2.07%
2023	2.27%	2.12%
2024	2.00%	2.00%
2025	2.00%	2.00%
2026	2.00%	2.00%
2027	2.00%	2.00%
2028	2.00%	2.00%
2029	2.00%	2.00%
2030	2.00%	2.00%
2031-56	1.75%	2.00%

Source: IMF *WEO*, IPA assumptions

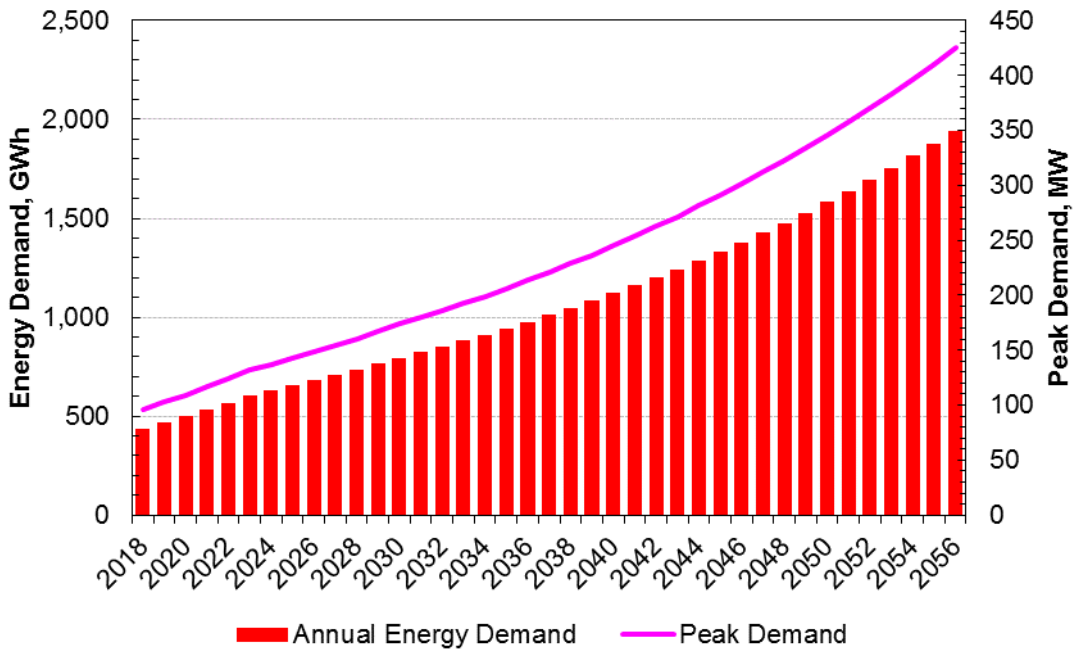
3.2 Demand

Electricity demand (total generation sent out) in Musandam increased from 266 GWh in 2012 to 352 GWh in 2016, a compound annual growth rate (CAGR) of 7.3%. RAECO forecasts that it will continue to increase at a slightly higher CAGR of 8.0% to 604 GWh in 2023. Peak demand is expected to grow slightly more strongly from 74 MW in 2016 to 132 MW in 2023, a CAGR of 8.6%. OPWP use this as the basis for their latest *Seven Year Statement 2017-23 (SYS)*, and we have similarly taken it for our outlook.

After 2023, we have assumed a linkage to assumed GDP growth. Musandam electricity demand increased at 2.3 times Omani GDP over the 2012-16 period – we have assumed a slightly lower elasticity of 2.0 times for the forecast. Hence annual and peak demand is assumed to grow at 4.0% *per annum* from 2024 to 2030, and at 3.5% thereafter.

Figure 2 below shows the resultant electricity demand forecast, with detailed figures provided in Table 3.

Figure 2: Electricity Demand Forecast



Source: RAECO, IPA assumptions and analysis

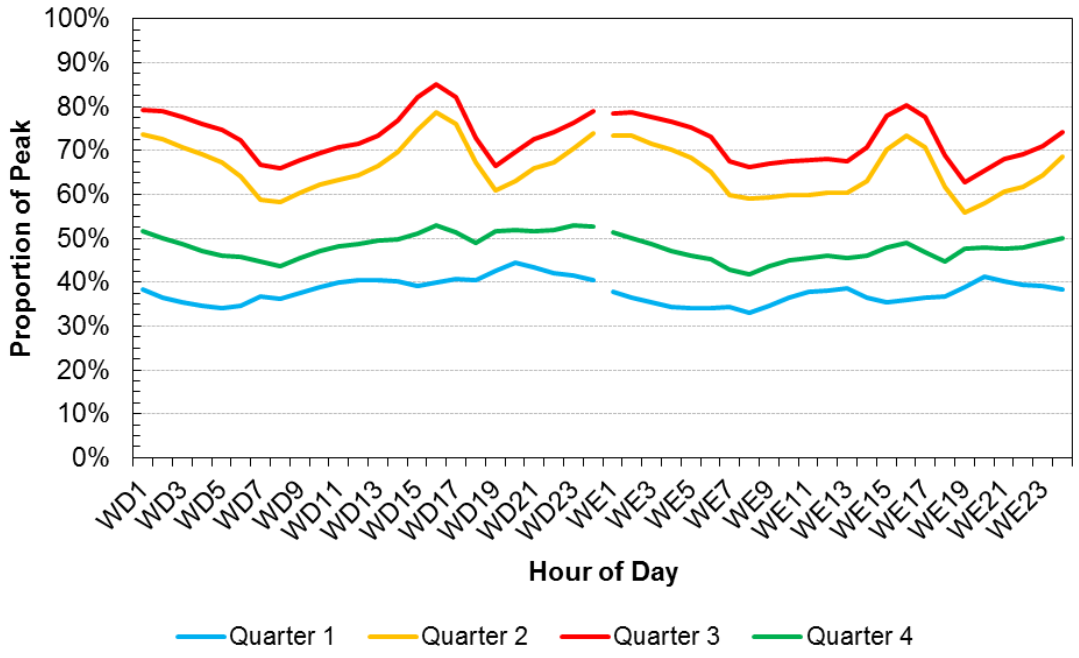
Table 3: Historic and Forecast Electricity Demand

	Year	Annual Electricity Demand, GWh	Growth Rate	Peak Electricity Demand, MW	Growth Rate
Historic	2012	266	-	-	-
	2013	289	8.7%	-	-
	2014	315	9.2%	65	-
	2015	343	8.9%	-	-
	2016	352	2.5%	74.0	-
RAECO Forecast	2017	389	10.6%	83.7	13.1%
	2018	438	12.6%	96.0	14.7%
	2019	468	6.7%	102.5	6.8%
	2020	500	7.0%	109.4	6.7%
	2021	532	6.4%	116.6	6.6%
	2022	566	6.3%	123.8	6.2%
	2023	604	6.7%	132.0	6.6%
Long-Term Forecast	2024	628	4.0%	137.3	4.0%
	2025	654	4.0%	142.8	4.0%
	2026	680	4.0%	148.5	4.0%
	2027	707	4.0%	154.4	4.0%
	2028	735	4.0%	160.6	4.0%
	2029	765	4.0%	167.0	4.0%
	2030	795	4.0%	173.7	4.0%
	2031	823	3.5%	179.8	3.5%
	2032	852	3.5%	186.1	3.5%
	2033	882	3.5%	192.6	3.5%
	2034	912	3.5%	199.3	3.5%
	2035	944	3.5%	206.3	3.5%
	2036	977	3.5%	213.5	3.5%
	2037	1,012	3.5%	221.0	3.5%
	2038	1,047	3.5%	228.7	3.5%
	2039	1,084	3.5%	236.7	3.5%
	2040	1,122	3.5%	245.0	3.5%
	2041	1,161	3.5%	253.6	3.5%
	2042	1,201	3.5%	262.5	3.5%
	2043	1,244	3.5%	271.7	3.5%
	2044	1,287	3.5%	281.2	3.5%
	2045	1,332	3.5%	291.0	3.5%
	2046	1,379	3.5%	301.2	3.5%
	2047	1,427	3.5%	311.7	3.5%
	2048	1,477	3.5%	322.7	3.5%
	2049	1,529	3.5%	333.9	3.5%
	2050	1,582	3.5%	345.6	3.5%
	2051	1,637	3.5%	357.7	3.5%
	2052	1,695	3.5%	370.2	3.5%
	2053	1,754	3.5%	383.2	3.5%
	2054	1,815	3.5%	396.6	3.5%
	2055	1,879	3.5%	410.5	3.5%
	2056	1,945	3.5%	424.9	3.5%

Source: RAECO *Annual Reports*, IPA assumptions and analysis

In order to capture the varying demand pattern within a year and across a day, we use two representative daily hourly load profiles per quarter – one for Saturday to Thursday, another for Fridays – based on actual historic hourly consumption data for Oman. These curves, shown in Figure 3 below, are in turn calibrated so that the maximum hourly demand in each year matches the peak energy demand forecast and so that the sum of all hourly demands equals the annual energy demand in Table 3 above.

Figure 3: Hourly Electricity Demand Profile



Source: OPWP, IPA analysis

Electricity consumption is highest in the summer months (Q2 and Q3) and has a noticeable uplift in the late afternoon due to air conditioning load.

3.3 Existing Plants

3.3.1 Musandam IPP

The Asset comprises fifteen Wärtsilä 34DF dual-fuel reciprocating engines (REs), with a total installed capacity of 120 MW, operating primarily on natural gas with light fuel oil as backup.

The plant is expected to have an operational lifetime of 40 years to the end of 2056, with the PPA with OPWP lasting until 23 January 2032 (for our analysis we have treated this as the end of 2031). The lifetime average thermal efficiency is forecast at 42.0% (a heat rate of 8,564 kJ/kWh) on a net lower heating value (LHV) basis. The annual maintenance rate has been based on the maximum allowed under the PPA, which are shaped according to annual demand: 0% April to September, 12.5% in October and March, and 25% for November to February 25%, giving an annual average of 10.4%. The expected forced outage rate (EFOR) is 2.0%.

Variable operating and maintenance (O&M) costs are taken from the PPA which specifies US$69.74 per engine running hour (ERH), equal to US$0.59/MWh assuming full load operation. Annual fixed costs are around US$7.2m in 2018, equivalent to US$60/kW/yr in real 2018 terms.

The technical, operating and cost assumptions for the plant are summarised in Table 4 below.

Table 4: Musandam IPP Assumptions

Parameter	Value
Type	Reciprocating Engine (RE)
Main Fuel	Natural Gas
Installed Capacity, MW	120.0
Dependable Capacity, MW (installed less EFOR)	117.6
Commercial Operation Date (COD)	2017
Technical Lifetime, years	40
PPA Term, years	15
Post-PPA Period	2032-56
Heat Rate, kJ/kWh (net LHV, lifetime average)	8,564
Thermal Efficiency (net LHV, lifetime average)	42.04%
Planned Maintenance Rate	10.40%
Effective Forced Outage Rate (EFOR)	2.00%
Variable O&M Costs, US$/MWh	0.59
Fixed O&M Costs, US$/kW/yr	60.00

Source: Client, IPA analysis

3.3.2 Other Plants

Besides the Asset, there are four other power plants serving the Musandam region which were the primary source of generation prior to the Asset's commissioning. These are all diesel-fired internal combustion (IC) engines owned and operated by RAECO, with a total installed capacity of just under 100 MW. Details of these are shown in Table 5 below.

Table 5: Musandam Other Existing Power Plants

Plant	Installed Capacity, MW	Thermal Efficiency, net LHV	Commercial Operation Date (COD)	Assumed Closure Date
Dibba	22	33.20%	1978	2018
Khasab	66	34.76%	1982	2018
Kumzar	0.5	17.79%	-	2018
Madha	11	31.43%	2012	2041
Total	**99.5**			

Source: RAECO *Annual Reports*, OPWP *Seven Year Statement*, IPA assumptions and analysis

The three oldest plants, which have been operating for almost 40 years, are due to be retired by RAECO once a new 78 MW upgrade at Khasab comes into operation later this year, so we have assumed their closure at that time. The newer plant at Madha is assumed to have a 30-year lifetime. Thermal efficiencies for the plants have been calculated from fuel consumption data reported by RAECO. A variable O&M cost of US$3.00/MWh has been assumed for these plants.

3.4 New Builds

We identify two types of new plant entrants (new builds): those that are assumed to come online exogenously and on a firm basis (firm new builds), and those that are additional and justified on economic merit alone (economic new builds). To meet forecast demand and the minimum reserve margin (12% over peak electricity demand), the modelling takes into account firm new builds and adds economic new builds when required on a least cost basis.

The only known firm new build is the new 78 MW Khasab IC plant mentioned above, which is assumed to enter full operation from 2019.

We expect for Musandam, given relative scale and siting constraints due to the geography of the region, that similar gas-fired RE plants as the Asset will be the long-term solution to meet further demand growth (as opposed to the large-scale high efficiency combined cycle gas turbines (CCGTs) built in the main part of the country), with diesel-fuelled IC engines continuing to provide back-up peaking capacity. We have also allowed renewable options, such as solar photovoltaic (PV) and wind, to be considered by the modelling. The government has introduced a support scheme for 2-4 kW rooftop solar PV systems, but it is not clear whether this will apply to Musandam. Similarly, RAECO and OPWP are tendering for wind and solar projects in other parts of the country, so we have allowed the model to determine their economic viability as part of the future generation mix.

The investment costs and build constraints applied to economic new builds are summarised in Table 6 below.

The total investment cost (TIC) is defined as of the time of commissioning and includes direct engineering, procurement and construction (EPC) costs, indirect costs, and interest during construction (IDC). We have assumed that future new RE plants will have similar costs to the Asset in real terms: the total project cost was US$232m of which US$37m was unique to the project and would not be expected to be incurred in general, giving a TIC of US$195m or US$1,625/kW.

The levelised real capital charge rate (LRCCR) is the percentage of the TIC required to be earned annually in order to finance the investment, taking account of the capital return requirements and the investment lifetime of each plant type. These have been calculated assuming a post-tax real weighted-average cost of capital (WACC) of 8.0%.

Table 6: New Build Cost Assumptions and Build Constraints

Type	TIC, US$/kW	LRCCR, % TIC	Annual Capital Repayment, US$/kW/yr	Max Annual Build Constraint, MW
RE	1,625	10.1%	164.0	-
IC	1,000	10.1%	100.9	-
Solar PV	1,000	10.5%	105.2	50
Wind	2,500	10.5%	263.1	50

Source: Client, IPA research and assumptions

We have allowed further new RE capacity to come online on an economic basis from 2021, and IC and renewables from 2020, allowing for the lead time for new project development.

Table 7 outlines the technical and cost assumptions for new build plants.

Table 7: New Build Plants Technical Parameters and Operating Costs

Type	Efficiency, net LHV	Variable O&M, US$/MWh	Fixed O&M, US$/kW/yr
RE	42.04%	0.59	60.00
IC	36.00%	2.00	20.00
Solar PV	-	0.00	25.00
Wind	-	0.00	50.00

Source: IPA research and assumptions

Solar PV and wind generation has been modelled based on historic average capacity factors for the region. Table 8 below specifies the assumed quarterly and annual capacity factors.

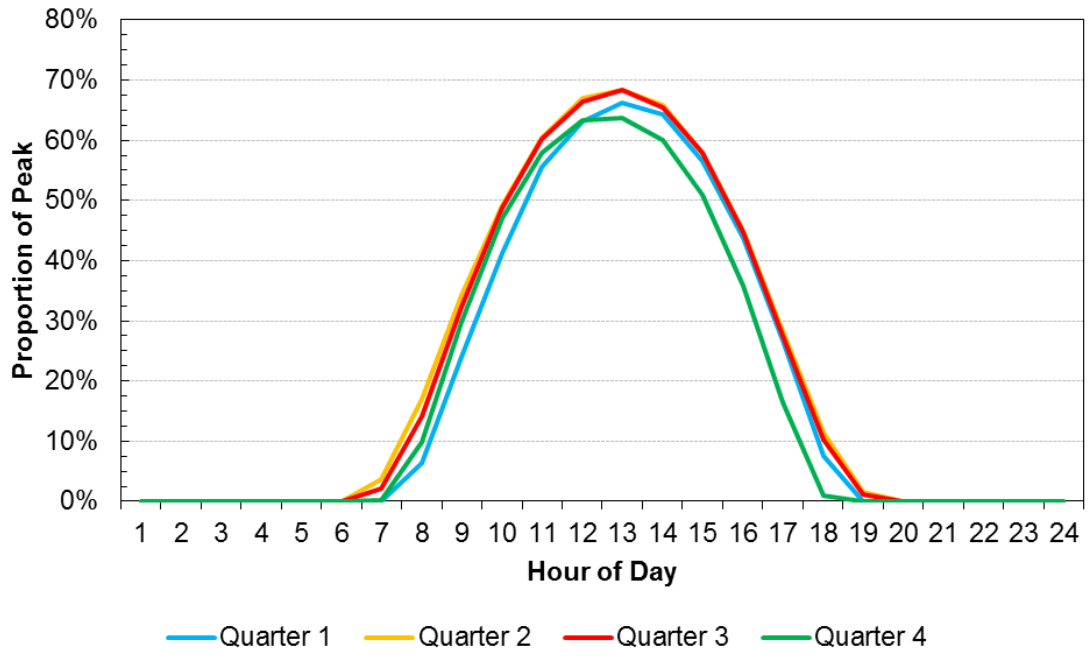
Table 8: Renewables Capacity Factors

Type	Q1	Q2	Q3	Q4	Annual
Solar PV	19.0%	21.2%	20.8%	18.2%	19.8%
Wind	28.9%	19.9%	22.1%	29.1%	25.0%

Source: IPA research and assumptions

Figure 4 below shows the assumed within-day hourly profiles for solar PV for each quarter.

Figure 4: Solar PV Hourly Generation Profiles



Source: IPA research and analysis

3.5 Fuel Prices

Natural gas is supplied to the plant at a subsidised rate of US$3.00/MMBtu (gross HHV) escalating at 3% annually on a nominal basis, resulting in real increase of just under 1% annually based on the forecast US$ inflation. We have assumed that this pricing will be maintained throughout in Musandam, giving gas prices as shown in Table 9 below. Diesel is assumed to be priced at US$0.36 per litre, equivalent to a 20% premium to domestic crude oil.

Table 9: Fuel Prices

real 2018	Natural Gas, US$/MMBtu	Diesel, US$/litre
2018	3.00	0.36
2019	3.02	0.36
2020	3.04	0.36
2021	3.07	0.36
2022	3.10	0.36
2023	3.13	0.36
2024	3.16	0.36
2025	3.19	0.36
2026	3.22	0.36
2027	3.25	0.36
2028	3.28	0.36
2029	3.31	0.36
2030	3.35	0.36
2031	3.38	0.36
2032	3.41	0.36
2033	3.45	0.36

Table 9: Fuel Prices

real 2018	Natural Gas, US$/MMBtu	Diesel, US$/litre
2034	3.48	0.36
2035	3.51	0.36
2036	3.55	0.36
2037	3.58	0.36
2038	3.62	0.36
2039	3.65	0.36
2040	3.69	0.36
2041	3.73	0.36
2042	3.76	0.36
2043	3.80	0.36
2044	3.84	0.36
2045	3.87	0.36
2046	3.91	0.36
2047	3.95	0.36
2048	3.99	0.36
2049	4.03	0.36
2050	4.07	0.36
2051	4.11	0.36
2052	4.15	0.36
2053	4.19	0.36
2054	4.23	0.36
2055	4.27	0.36
2056	4.31	0.36

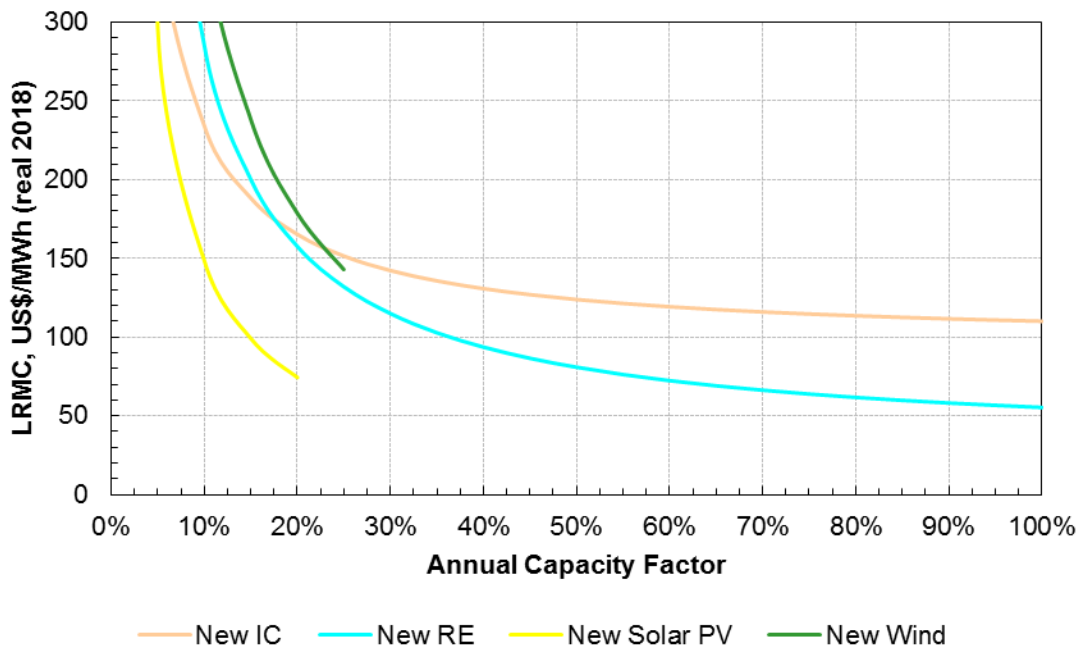
Source: Client, IPA assumptions

3.6 New Build Cost Comparison

The long-run marginal cost (LRMC) of a power plant is the total cost of electricity production accounting for the investment in new capacity. It comprises two components: (a) the short-run marginal cost (SRMC) of production which includes fuel and variable O&M costs, and (b) the annualised fixed O&M costs and capital repayment costs, taking into account the plant's operational capacity factor.

Figure 5 below compares the LRMC of all economic power new builds at varying annual capacity factors in the Asset's first post-PPA year, 2032, derived from the assumptions detailed above. The renewable technologies are curtailed at their assumed maximum production level. This provides a useful indicative way of identifying which technology is the most cost-effective for different operational roles.

Figure 5: New Build LRMC 2032



Source: IPA assumptions and analysis

We can see that REs are the most economic choice for mid-merit and baseload operation above annual capacity factors of around 20%, while ICs are the economic choice for controllable, peaking operation below that level. Solar PV would be cost competitive at its limited load factor, but the defined restricted operation may count against it, especially as production does not necessarily coincide with peak demand.

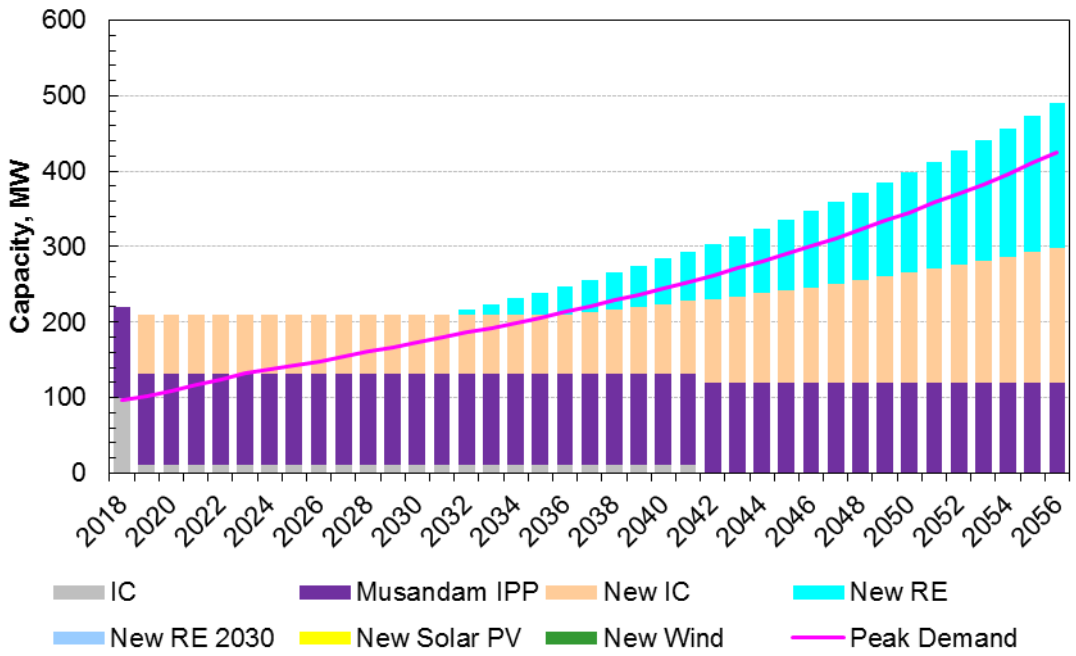
4 Electricity Market Outlook

This section presents our base case outlook for the development of the Musandam Power System to 2056, determined using the assumptions outlined previously.

4.1 Capacity Development

Figure 6 below presents the forecast capacity mix in Musandam. The Musandam IPP and the new Khasab upgrade are expected to be sufficient to meet demand until 2032, at which point new RE plants similar to the Asset would be required with new IC plants for peaking purposes needed from 2036.

Figure 6: Musandam Forecast Capacity Development

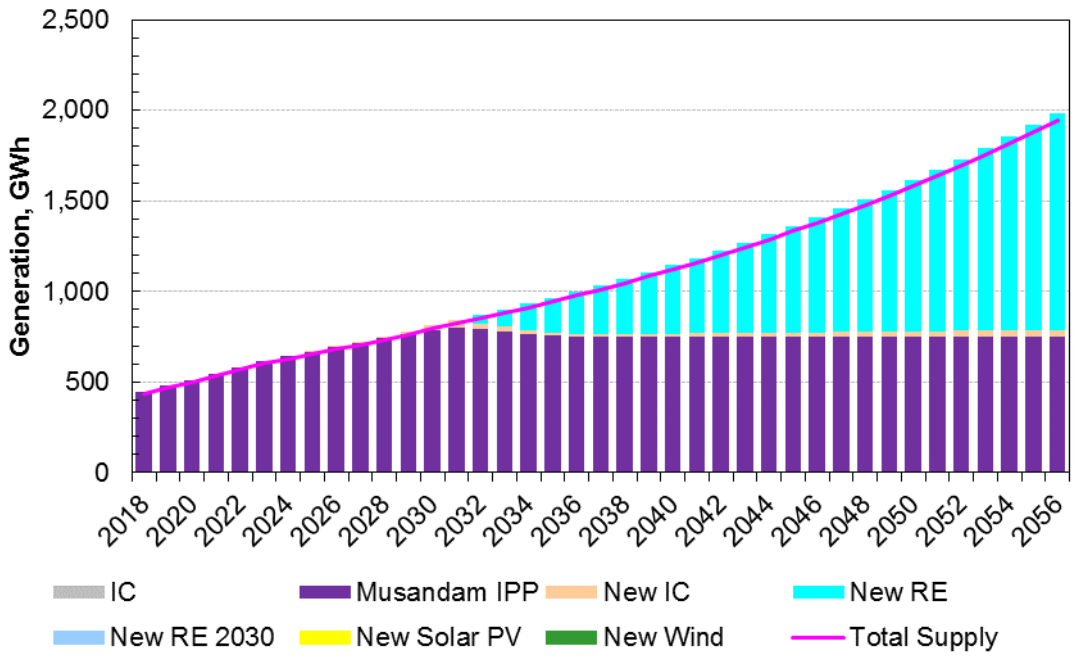


Source: IPA analysis

4.2 Generation Mix

The corresponding generation mix is shown in Figure 7 below. The Musandam IPP dominates generation until further new RE are built, with a small amount from IC plants in the peak periods starting from 2025.

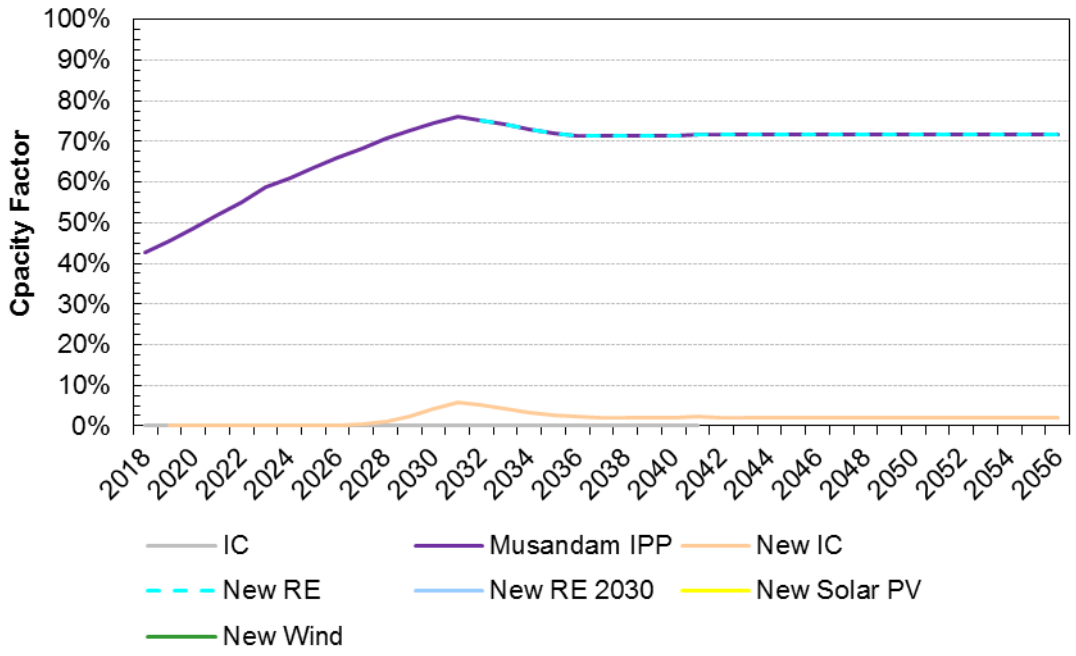
Figure 7: Musandam Forecast Power Generation Mix



Source: IPA analysis

Annual capacity factors are shown for each plant type in Figure 8 below. The Asset initially shows relatively low annual capacity factors, due to the significant variation in demand across the year – it operates much closer to full load in the summer months, and much less in the winter. Its capacity factor increases as demand grows, and IC plants are required for peaking operation. Once demand has reached the level for new build, the Asset and the new RE operate at similar baseload levels around 70%, while the new IC plants run at around 2%.

Figure 8: Musandam Forecast Power Plant Annual Capacity Factors



Source: IPA analysis

4.3 Market "Prices"

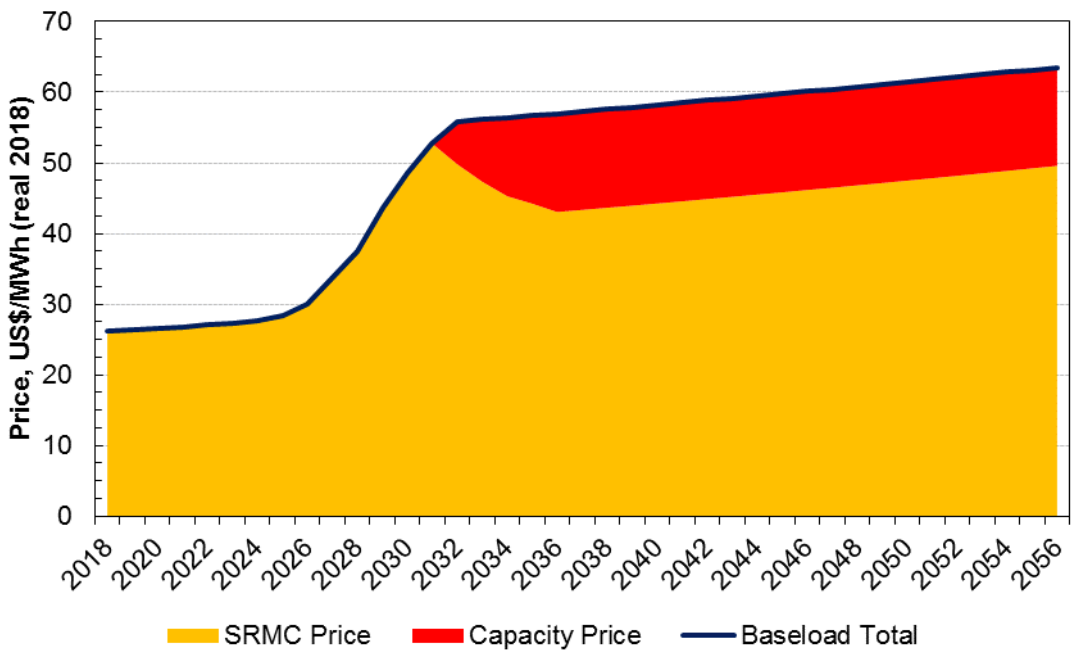
In this section we present our forecast of the notional wholesale electricity price, reflecting the underlying costs of supply, which we would expect to see were a liberalised market to be introduced in the MPS. These price forecasts are made up of the following two components:

- **SRMC Price**: This is the price that results from plants recovering their short-run marginal costs (SRMC) of production, comprising fuel and variable O&M costs, in each period when they generate/produce. The most expensive plant required to satisfy demand sets the price for the period.
- **Capacity Premium**: After taking its SRMC-related margin into account, the capacity premium identifies the minimum payment required so that the most cost-effective economic new build fully recovers its fuel and O&M costs and is able to service its invested capital (debt and equity) at market rates. This represents the opportunity cost of capacity in the system. It is a function of market revenues and should not be confused with the capacity payment defined under a PPA.

Figure 9 and Table 10 shows our forecast electricity prices. The SRMC price initially increases in line with the underlying gas price at just under 1% *per annum* (in real terms), from US$26.23/MWh to US$27.56/MWh in 2024. From 2025 to 2031, there is a much sharper increase as the diesel-fired IC plants are increasingly needed for peak generation and set prices over a number of periods. From 2032 when economic new build is needed to meet growing demand, a capacity premium is required, at first to remunerate the new RE plant, and from 2036 onwards to also allow for new IC at a total level of US$122/kW/yr (uS$13.94/MWh). The SRMC price declines from its peak in 2031 to 2036, as gas generation takes over again from diesel.

The long-term total baseload price rises gradually (as gas prices are assumed to continue to increase) from around US$56/MWh in 2033 to over US$63/MWh by the end of the forecast.

Figure 9: Musandam Electricity Price Forecast



Source: IPA analysis

Table 10: Musandam Electricity Prices

real 2018	SRMC Price, US$/MWh	Capacity Premium, US$/kW/yr	Capacity Price, US$/MWh	Total Baseload Price, US$/MWh
2018	26.23	0.00	0.00	26.23
2019	26.37	0.00	0.00	26.37
2020	26.59	0.00	0.00	26.59
2021	26.83	0.00	0.00	26.83
2022	27.07	0.00	0.00	27.07
2023	27.30	0.00	0.00	27.30
2024	27.56	0.00	0.00	27.56
2025	28.43	0.00	0.00	28.43
2026	30.02	0.00	0.00	30.02
2027	33.85	0.00	0.00	33.85
2028	37.52	0.00	0.00	37.52
2029	43.59	0.00	0.00	43.59
2030	48.50	0.00	0.00	48.50
2031	52.73	0.00	0.00	52.73
2032	49.81	52.82	6.03	55.84
2033	47.34	76.97	8.79	56.13
2034	45.28	97.49	11.13	56.41
2035	44.24	109.17	12.46	56.71
2036	43.06	122.13	13.94	57.00
2037	43.35	122.13	13.94	57.30
2038	43.65	122.13	13.94	57.60
2039	43.96	122.13	13.94	57.90
2040	44.26	122.13	13.94	58.21
2041	44.57	122.13	13.94	58.52
2042	44.89	122.13	13.94	58.83
2043	45.20	122.13	13.94	59.14
2044	45.52	122.13	13.94	59.46
2045	45.84	122.13	13.94	59.78
2046	46.16	122.13	13.94	60.11
2047	46.49	122.13	13.94	60.43
2048	46.82	122.13	13.94	60.76
2049	47.16	122.13	13.94	61.10
2050	47.49	122.13	13.94	61.44
2051	47.84	122.13	13.94	61.78
2052	48.18	122.13	13.94	62.12
2053	48.53	122.13	13.94	62.47
2054	48.88	122.13	13.94	62.82
2055	49.23	122.13	13.94	63.17
2056	49.59	122.13	13.94	63.53

Source: IPA analysis

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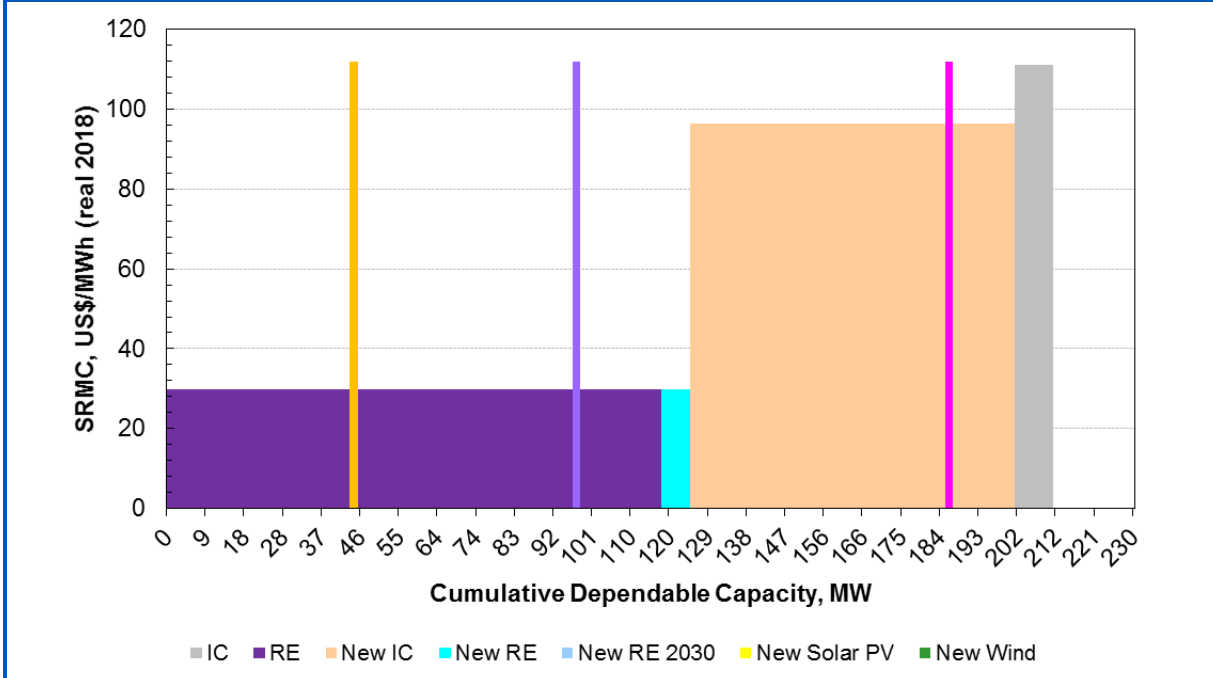
5 Musandam IPP Post-PPA Outlook

This section presents our base case forecast for the Musandam IPP in the post-PPA period. We first review the expected position of the plant in the merit order, present forecast operation, and then the post-PPA value.

5.1 Merit Order Positioning

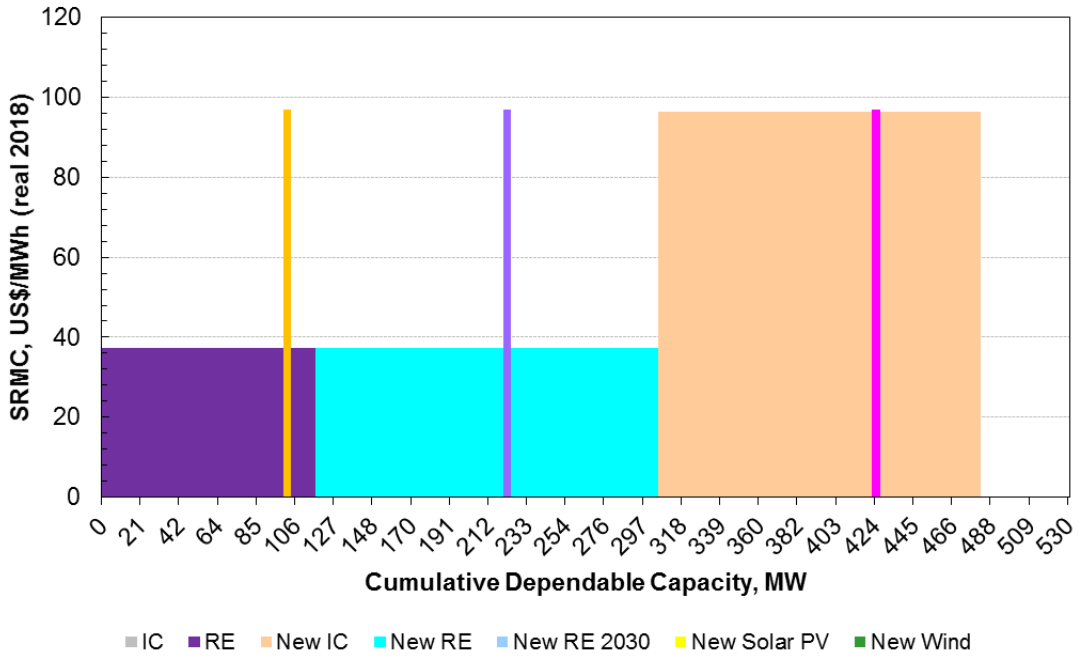
Figure 10 and Figure 11 below show the merit order in 2032 after the expiry of the PPA and in 2056 just before the Asset's closure. This ranks all plants according to their SRMC, from lowest to highest. By overlaying the annual minimum, average and maximum hourly demand, we can obtain a general view of how much plants are likely to be called to dispatch over the year.

Figure 10: Merit Order 2032



Source: IPA analysis

Figure 11: Merit Order 2046



Source: IPA analysis

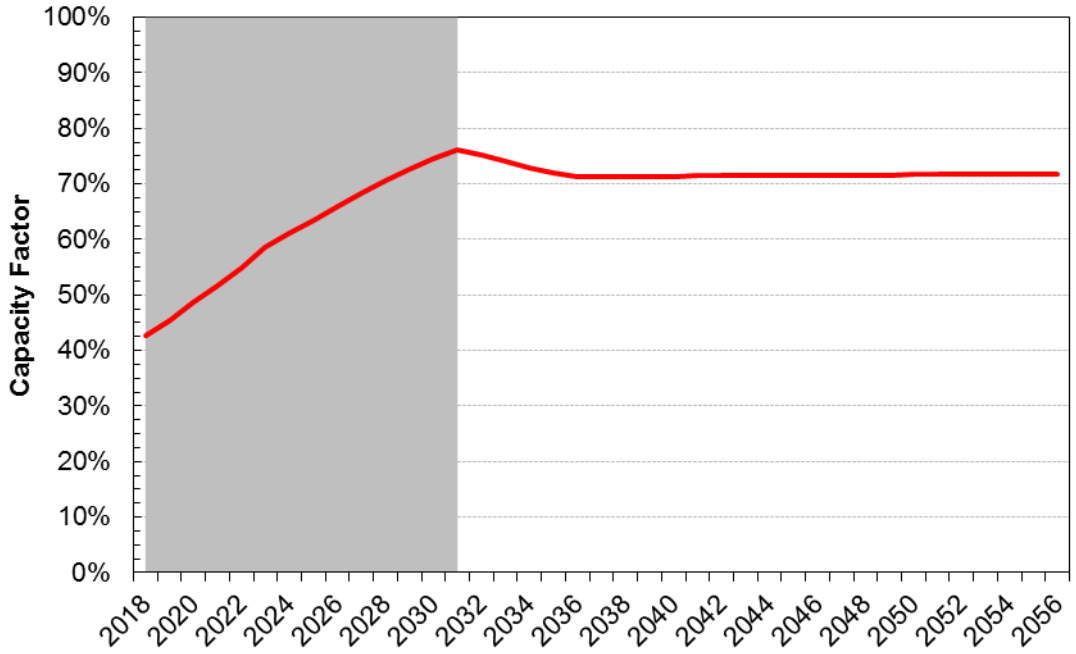
We can see that the Asset is expected to remain the most cost-competitive generation source along with future new RE units, hence operating baseload throughout as seen above.

5.2 Post-PPA Operation

The plant's forecast annual capacity factor over its lifetime is shown in Figure 12, and its post-PPA quarterly generation and capacity factors are detailed in Table 11 and Table 12 respectively below. These figures have been calculated on a purely economically rational basis according to the relative merit order of the plant against others on the system, which is the proper basis to determine its economic value. However, during the PPA period in particular, RAECO/OPWP may choose to dispatch the plant differently for system-wide support or other technical reasons and hence the results shown may not be fully applicable up to 2032.

As described above, the Asset initially operates at relatively low annual capacity factors matching the varying demand through the year, and increasing in line with demand growth. It peaks in 2031 before additional new RE plant is built, and then steadies out at baseload operation slightly above 71% capacity factor, 750+ GWh production per year, increasing slightly year-on-year with growing demand (offset by additional new build).

Figure 12: Musandam IPP Forecast Capacity Factor



Note: PPA period is shaded, when plant may be dispatched differently by RAECO.
Source: IPA analysis

Production is highly seasonal in line with demand, with near maximum operation in the summer months (Q2 and Q3), and much lower operation in the winter (Q1 and Q4).

Table 11: Musandam IPP Post-PPA Generation

GWh	Q1	Q2	Q3	Q4	Annual
2032	120	243	258	169	790
2033	117	239	257	165	778
2034	115	236	255	162	767
2035	112	232	253	158	756
2036	111	230	252	157	751
2037	111	230	252	157	751
2038	111	230	252	157	751
2039	111	230	252	157	751
2040	111	230	252	157	751
2041	112	231	253	157	752
2042	112	231	253	157	752
2043	112	231	253	157	752
2044	112	231	253	157	752
2045	112	231	253	157	752
2046	112	231	253	157	752
2047	112	231	253	157	752
2048	112	231	253	157	752
2049	112	231	253	157	752
2050	112	231	253	158	754
2051	112	231	253	158	754
2052	112	231	253	158	754
2053	112	231	253	158	754
2054	112	231	253	158	754

Table 11: Musandam IPP Post-PPA Generation

GWh	Q1	Q2	Q3	Q4	Annual
2055	112	231	253	158	754
2056	112	231	253	158	754

Source: IPA analysis

Table 12: Musandam IPP Post-PPA Capacity Factors

	Q1	Q2	Q3	Q4	Annual
2032	46.3%	92.6%	97.4%	63.8%	75.1%
2033	45.2%	91.3%	96.9%	62.3%	74.1%
2034	44.2%	89.9%	96.3%	61.0%	73.0%
2035	43.3%	88.6%	95.6%	59.7%	71.9%
2036	42.9%	87.9%	95.2%	59.1%	71.4%
2037	42.9%	87.9%	95.2%	59.1%	71.4%
2038	42.9%	87.9%	95.2%	59.1%	71.4%
2039	42.9%	87.9%	95.2%	59.1%	71.4%
2040	42.9%	87.9%	95.2%	59.1%	71.4%
2041	43.0%	88.1%	95.4%	59.3%	71.6%
2042	43.0%	88.1%	95.4%	59.3%	71.6%
2043	43.0%	88.1%	95.4%	59.3%	71.6%
2044	43.0%	88.1%	95.4%	59.3%	71.6%
2045	43.0%	88.1%	95.4%	59.3%	71.6%
2046	43.0%	88.1%	95.4%	59.3%	71.6%
2047	43.0%	88.1%	95.4%	59.3%	71.6%
2048	43.0%	88.1%	95.4%	59.3%	71.6%
2049	43.0%	88.1%	95.4%	59.3%	71.6%
2050	43.1%	88.3%	95.5%	59.5%	71.7%
2051	43.1%	88.3%	95.5%	59.5%	71.7%
2052	43.1%	88.3%	95.5%	59.5%	71.7%
2053	43.1%	88.3%	95.5%	59.5%	71.7%
2054	43.1%	88.3%	95.5%	59.5%	71.7%
2055	43.1%	88.3%	95.5%	59.5%	71.7%
2056	43.1%	88.3%	95.5%	59.5%	71.7%

Source: IPA analysis

5.3 Post-PPA Value

5.3.1 Single Buyer Approach

Our assessment of the plant's long-term value is based on the avoided cost basis, which is the most likely way that any extension of the PPA would be assessed by OPWP at that time given the small nature of the Musandam Power System.

We model the plant's closure at the end of its PPA in 2031 and compare the difference in the total system costs with and without it. The additional costs of building new facilities to replace it plus any differences in operating costs would be costs that OPWP could avoid by extending the offtake contract, and hence represent the value that should be willing to be paid to MPC for such an extension.

If the Asset was closed, it would need to be replaced with a corresponding 120 MW new RE plant, which based on the assumptions outlined in Table 6 above would cost US$1,625/kW to build, equal to a total of US$195m in real 2018 terms. This corresponds to an annual capex repayment of US$19.68m at the required 10.1% LRCCR. Since these new RE plants are assumed to have similar performance and operating costs as the Asset, there would be no savings in fuel consumption or O&M costs to be achieved.

Hence the total avoided cost to the single buyer of extending the Asset's contract beyond 15 years is this new build capex repayment of **US$19.68m per year (real 2018)**. Based on the assumed inflation rate, this corresponds to nominal values of US$26.17m in 2032 rising to US$42.09m in 2056, averaging US$33.52m over the period, as shown in Table 13 below.

Table 13: Musandam IPP Single Buyer Avoided Costs

US$m	Capex Repayment (real 2018)	Fuel and O&M Cost Savings (real 2018)	Avoided Costs (real 2018)	Avoided Costs (nominal)
2032	19.68	0.00	19.68	26.17
2033	19.68	0.00	19.68	26.69
2034	19.68	0.00	19.68	27.22
2035	19.68	0.00	19.68	27.77
2036	19.68	0.00	19.68	28.32
2037	19.68	0.00	19.68	28.89
2038	19.68	0.00	19.68	29.47
2039	19.68	0.00	19.68	30.06
2040	19.68	0.00	19.68	30.66
2041	19.68	0.00	19.68	31.27
2042	19.68	0.00	19.68	31.90
2043	19.68	0.00	19.68	32.53
2044	19.68	0.00	19.68	33.19
2045	19.68	0.00	19.68	33.85
2046	19.68	0.00	19.68	34.53
2047	19.68	0.00	19.68	35.22
2048	19.68	0.00	19.68	35.92
2049	19.68	0.00	19.68	36.64
2050	19.68	0.00	19.68	37.37
2051	19.68	0.00	19.68	38.12
2052	19.68	0.00	19.68	38.88
2053	19.68	0.00	19.68	39.66
2054	19.68	0.00	19.68	40.45

Table 13: Musandam IPP Single Buyer Avoided Costs				
US$m	**Capex Repayment (real 2018)**	**Fuel and O&M Cost Savings (real 2018)**	**Avoided Costs (real 2018)**	**Avoided Costs (nominal)**
2055	19.68	0.00	19.68	41.26
2056	19.68	0.00	19.68	42.09
Average 2032-56	**19.68**	**0.00**	**19.68**	**33.52**
Source: IPA analysis				

It should be noted that there may need to be additional capital investment requirements in the post-PPA period to ensure the Asset is able to operate for this 40-year lifetime. Such expenditure would need to be offset against the avoided costs shown above in assessing the net post-PPA value, an analysis which lies outside the scope of this assignment.

5.3.2 Market-Based Cash Flow

For comparison, we also consider the value of the plant on a liberalised market basis. We calculate power revenues based on the prices in each period when the plant operates, plus attribute the value of the plant's capacity based on the calculated capacity premia. Table 14 below shows the Asset's forecast revenue after the expiry of its PPA.

Table 14: Musandam IPP Post-PPA Market-Based Revenue			
US$m (real 2018)	**Energy**	**Capacity**	**Total**
2032	44.16	6.21	50.37
2033	41.21	9.05	50.26
2034	38.67	11.46	50.14
2035	37.18	12.84	50.02
2036	35.71	14.36	50.08
2037	35.94	14.36	50.30
2038	36.16	14.36	50.52
2039	36.39	14.36	50.75
2040	36.62	14.36	50.98
2041	36.91	14.36	51.27
2042	37.15	14.36	51.51
2043	37.38	14.36	51.75
2044	37.62	14.36	51.99
2045	37.86	14.36	52.23
2046	38.11	14.36	52.47
2047	38.35	14.36	52.72
2048	38.60	14.36	52.97
2049	38.86	14.36	53.22
2050	39.16	14.36	53.52
2051	39.41	14.36	53.78
2052	39.67	14.36	54.04
2053	39.93	14.36	54.30
2054	40.20	14.36	54.56
2055	40.47	14.36	54.83
2056	40.74	14.36	55.10
Average 2032-56	**38.50**	**13.65**	**52.15**
Note figures may not add due to rounding. Source: IPA analysis			

Energy revenues follow the trend of the SRMC prices presented above, initially falling to just under US$36/MWh in 2036 and then rising gradually with the underlying gas price. The value of capacity increases with the capacity premium, reaching its steady long-term value in 2036. Total revenues from electricity sales range between US$50m and US$55m over the period, averaging just over US$52m.

The corresponding costs of production are shown in Table 15 below. Fuel costs initially fall in line with slightly declining generation, then rise gradually with the underlying gas cost. Variable O&M costs average US$0.45m/yr and fixed O&M costs are US$7.20m/yr. Total costs rise from just over US$30m to US$35m in the period.

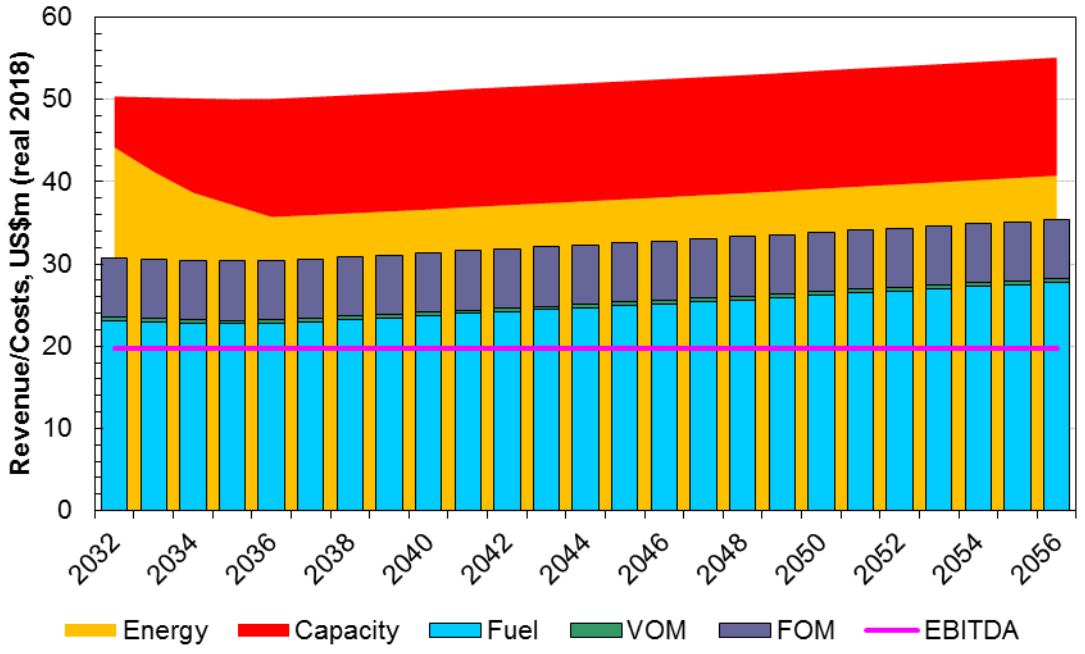
Table 15: Musandam IPP Post-PPA Market-Based Costs

US$m (real 2018)	Gas	Variable O&M	Fixed O&M	Total
2032	23.03	0.47	7.20	30.69
2033	22.92	0.46	7.20	30.58
2034	22.81	0.45	7.20	30.46
2035	22.69	0.45	7.20	30.34
2036	22.75	0.45	7.20	30.40
2037	22.98	0.45	7.20	30.62
2038	23.20	0.45	7.20	30.85
2039	23.43	0.45	7.20	31.07
2040	23.66	0.45	7.20	31.30
2041	23.95	0.45	7.20	31.60
2042	24.18	0.45	7.20	31.83
2043	24.42	0.45	7.20	32.07
2044	24.66	0.45	7.20	32.31
2045	24.90	0.45	7.20	32.55
2046	25.15	0.45	7.20	32.79
2047	25.39	0.45	7.20	33.04
2048	25.64	0.45	7.20	33.29
2049	25.89	0.45	7.20	33.54
2050	26.19	0.45	7.20	33.84
2051	26.45	0.45	7.20	34.10
2052	26.71	0.45	7.20	34.36
2053	26.97	0.45	7.20	34.62
2054	27.24	0.45	7.20	34.88
2055	27.50	0.45	7.20	35.15
2056	27.77	0.45	7.20	35.42
Average 2032-56	**24.82**	**0.45**	**7.20**	**32.47**

Note figures may not add due to rounding.
Source: IPA analysis

These total revenues less total costs provide the estimated operating cash flow (or earnings before interest, tax, depreciation and amortisation, EBITDA). This is summarised in Figure 13 and detailed in Table 16 below.

Figure 13: Musandam IPP Post-PPA Cash Flow



Source:

With costs mirroring the revenue trend, EBITDA is forecast to be steady in the post-PPA period at **US$19.68m per year (real 2018)**, exactly equal to the single buyer avoided costs calculated above.

Table 16: Musandam IPP Post-PPA Market-Based Cash Flow

US$m	Revenues (real 2018)	Costs (real 2018)	EBITDA (real 2018)	EBITDA (nominal)
2032	50.37	30.69	19.68	26.17
2033	50.26	30.58	19.68	26.69
2034	50.14	30.46	19.68	27.22
2035	50.02	30.34	19.68	27.77
2036	50.08	30.40	19.68	28.32
2037	50.30	30.62	19.68	28.89
2038	50.52	30.85	19.68	29.47
2039	50.75	31.07	19.68	30.06
2040	50.98	31.30	19.68	30.66
2041	51.27	31.60	19.68	31.27
2042	51.51	31.83	19.68	31.90
2043	51.75	32.07	19.68	32.53
2044	51.99	32.31	19.68	33.19
2045	52.23	32.55	19.68	33.85
2046	52.47	32.79	19.68	34.53
2047	52.72	33.04	19.68	35.22
2048	52.97	33.29	19.68	35.92
2049	53.22	33.54	19.68	36.64
2050	53.52	33.84	19.68	37.37
2051	53.78	34.10	19.68	38.12
2052	54.04	34.36	19.68	38.88
2053	54.30	34.62	19.68	39.66

Table 16: Musandam IPP Post-PPA Market-Based Cash Flow

US$m	Revenues (real 2018)	Costs (real 2018)	EBITDA (real 2018)	EBITDA (nominal)
2054	54.56	34.88	19.68	40.45
2055	54.83	35.15	19.68	41.26
2056	55.10	35.42	19.68	42.09
Average 2032-56	**52.15**	**32.47**	**19.68**	**33.52**

Note figures may not add due to rounding.
Source: IPA analysis

5.3.3 Sensitivity Analysis

We have also modelled various sensitivities to highlight the key drivers of this expected post-PPA value. We examined the impact of the following input assumptions:

- **Demand Growth**: We have examined higher and lower demand growth based on OPWP's high and low cases to 2023, and then a ± ½ percentage point change in both annual and peak demand growth thereafter.
- **Cost of New Builds**: We have considered both a ± 10% variation on the TIC for new builds, and a ± 1 percentage point variation in the WACC.
- **High Gas Pricing**: We examined an alternative gas pricing situation, reflecting the cost of delivered liquefied natural gas (LNG) at around US$6.25/MMBtu.
- **Firm Solar PV Build**: We have considered a case where the rooftop solar support scheme is adopted in the region, with 1 MW installed per year from 2020 onwards.
- **Technology Improvement**: We have considered the situation where future new RE plants will be 2 percentage points more efficient than the Asset.

For each of these cases, we compared the total system costs of keeping the plant open against closing it at the end of its PPA.

The results of these sensitivities on the average annual post-PPA single buyer cost savings are presented in Table 17 below.

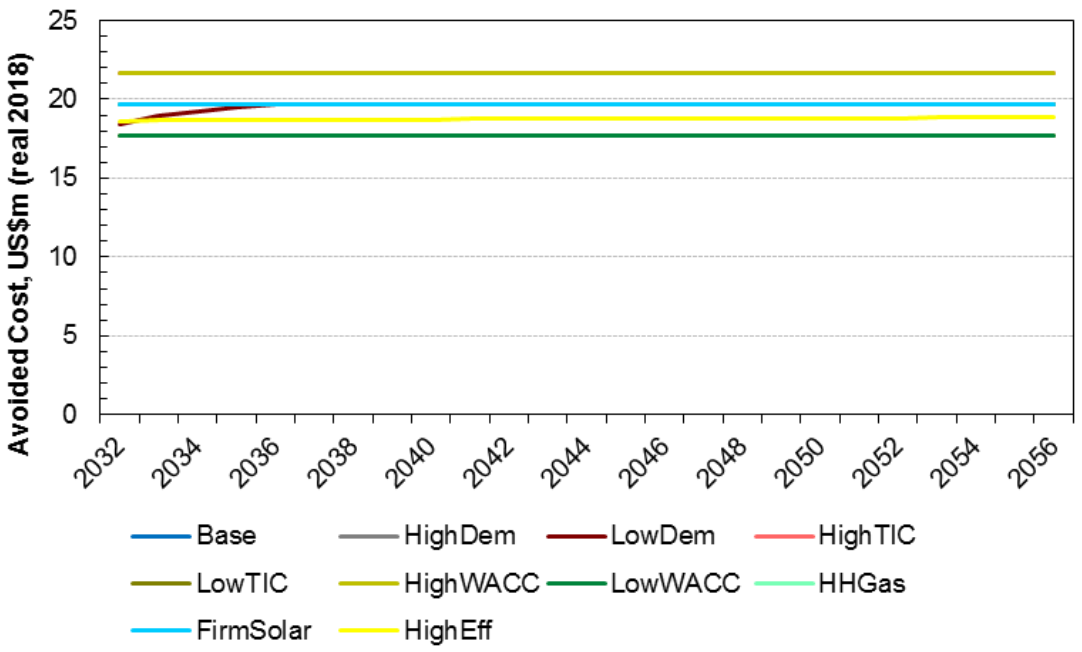
Table 17: Post-PPA Avoided Costs Sensitivity

Sensitivity	Annual Average Avoided Costs 2032-56, US$m (real 2018)	Variation to Base
Base Case	19.68	-
High Demand	19.68	0.0%
Low Demand	19.57	-0.5%
High Capex	21.65	+10.0%
Low Capex	17.71	-10.0%
High WACC	21.71	+10.3%
Low WACC	17.71	-10.0%
High Gas	19.68	0.0%
Firm Solar	19.68	0.0%
High New Efficiency	18.76	-4.7%

Source: IPA analysis

The biggest impact on post-PPA value comes from variations in the future cost of alternative new build plants, whether in terms of capex or financing costs, as these set the competitive benchmark against which a contract extension would be assessed. This effect is uniform over the period, and broadly linear with the degree of variation, as shows in Figure 14 below.

Figure 14: Musandam IPP Post-PPA Avoided Costs Sensitivity



Source: IPA analysis

The next most significant impact comes from any future technological improvements resulting in higher future new plant efficiency. This would reduce the post-PPA value by about 5%, through fuel cost savings which would slightly offset the capex repayment required for alternative new plants.

Low future demand growth has a small impact in the first few years of the post-PPA period, as slightly less new plant would have be built, but then reaches the base level once the plant's full capacity is needed. High demand growth, future solar build and high gas prices have no effect on the value, as the need for new build is not changed in any case and the costs of generation are identical for the new plant and the Musandam IPP.

6 Summary and Conclusions

In summary, given the expected growth in electricity demand in the Musandam Governorate, with a near doubling in annual and peak demand by 2032, the Musandam IPP is expected to have considerable residual value at the expiry of its PPA for the remaining twenty-five years of its expected technical lifetime.

We estimate that it could provide average annual cost savings to the single buyer, or annual net cash flow, of **US$19.7 million in real 2018 terms from 2032 to 2056, an average of US$33.5m in nominal terms over the period** (not allowing for any required capital investments to ensure continued operation for this time).

The future costs of alternative power generation plants at the time of the PPA expiry have the most significant, and a relatively linear, impact on value. Any reductions in capital or financing costs from current levels in real terms will correspondingly reduce the cost savings which the single buyer could achieve by keeping the plant online, and conversely any increases would boost them, and hence the value of the plant. Similarly any future technological improvements would adversely affect the value by providing potential fuel savings relative to the plant.

Lower demand growth would have a small impact on the post-PPA value, while increases in demand growth or gas prices, and level of renewables generation are expected to have no impact, as none of these affect the need for the Asset to be maintained on the system as a baseload generator.

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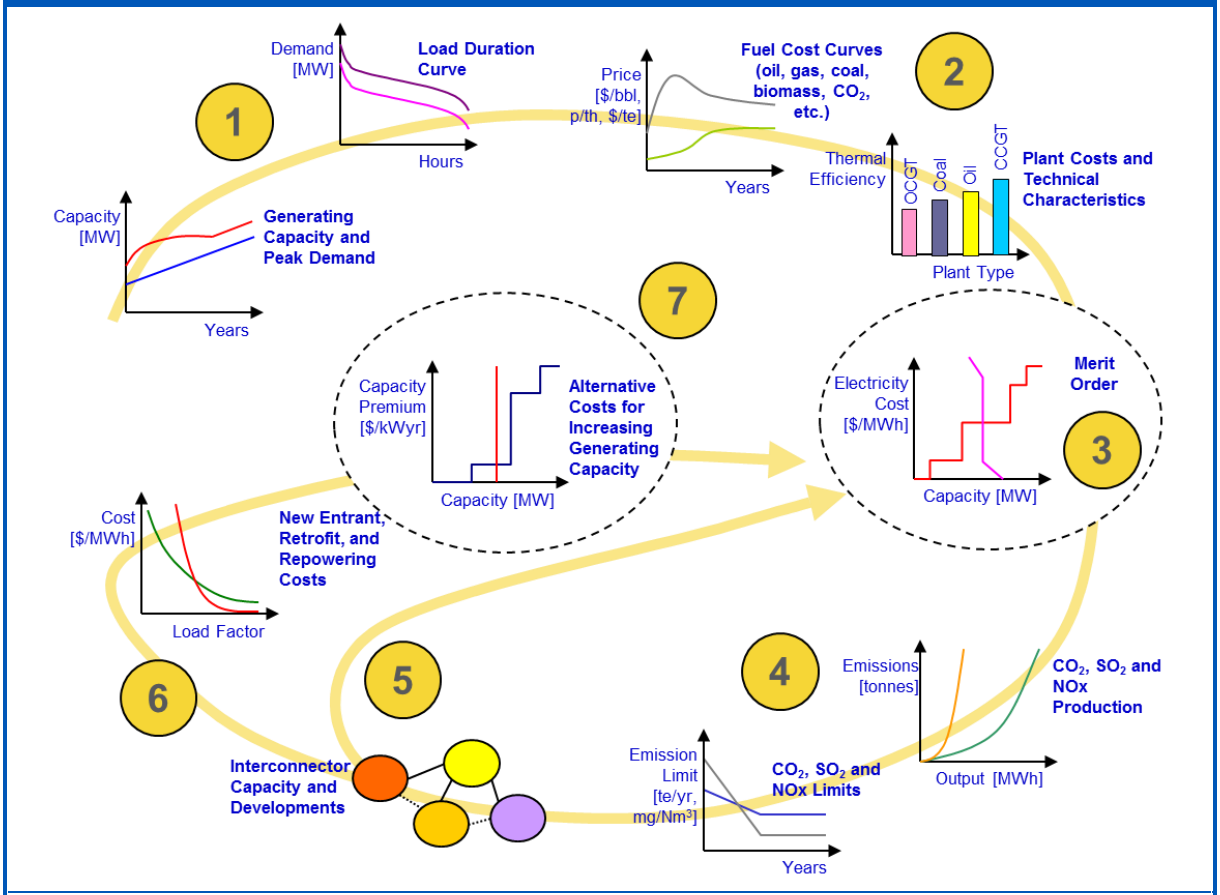
Annex A: Introduction to ECLIPSE™

IPA's ECLIPSE™ (*Emissions, Constraints and Legislation Interactions in Power System Economics*) modelling framework is designed to simulate the developments of actual power systems. By incorporating the actual constraints facing participants in the real world, ECLIPSE™ replicates how decisions are made when subject to a slate of operational constraints, whether physical, economic, environmental, or legislative.

The model is based on a deterministic linear programming (LP) approach with the objective of minimising the present value of fuel, operating and maintenance (O&M), and capital investment costs across the whole forecast horizon. The resulting prices, dispatch, fuel consumption, and capacity expansion are economically optimal for each set of input parameters and constraints. Our models are developed as bespoke applications in Excel with a compatible LP optimiser (What's*Best!* from LINDO Systems) and designed for a fast turnaround to enable the consideration of multiple scenarios.

Conceptually, it is possible to think of the model as carrying out a series of discrete tasks, as graphically depicted in Figure 15 and described further below. For illustration, this is based on the application to the electricity market alone. When we add heat production via cogeneration or water desalination, the markets become interlinked via respective joint power/heat or power/water constraints of the power plants, and the incremental demand for electricity from desalination plants.

Figure 15: ECLIPSE™ Conceptual Representation



Source: IPA

1. **Current Capacity and Demand**: Detailed information of the characteristics of demand and existing generating capacity is required. Demand for electricity can be subdivided into two key components: hourly demand and total annual demand. The hourly demand, or load profile, is the demand for electrical energy on an hour-by-hour basis across the whole year. In addition to this demand being met, an adequate safety margin needs to be maintained in the form of non-generating capacity in case of any sudden plant failures. This capacity reserve margin is measured as a percentage of the highest demand in the year (peak demand). Each power plant can provide both electricity and firm capacity to satisfy the hourly demand and capacity reserve margin respectively. The former will be a function of resource availability and plant maintenance. The contribution each power plant makes to the reserve margin will be determined by its availability in the peak. The unreliability of certain sources, including wind, solar and hydroelectric plants, will be reflected by derating their reserve margin contributions.
2. **Station-Specific Operational Costs**: When determining how to generate electricity to meet a certain level of demand at minimum cost, available power stations need to be ranked according to their generation-specific operating costs. This includes fuel and non-fuel operating and maintenance costs. Information on fuel options, fuel prices and detailed information on the technical characteristics of the existing power stations is required. The marginal fuel cost will take into account the fuel price and the technology-specific fuel-to-electricity conversion factor (thermal efficiency).
3. **Initial Dispatch of Resources to Meet Demand**: Once the costs per unit have been defined, the model dispatches as many resources as required. Notwithstanding other constraints described below, the lowest cost resources will be dispatched first. Dispatch can be optimised to take into account any requirements to meet ancillary services.
4. **Environmental, Fuel and Cogeneration Constraints**: The relative cost of production of different power stations can also be affected by the application of environmental constraints. For example, if a power station has to pay for allowances to cover its emissions of CO2, this additional cost must be added to its costs of production. ECLIPSE™ takes these types of constraints into account whether these are defined in terms of allowance prices (measured per unit of pollutant emitted) or emission limits (measured as weight limits or rate caps). Fuel supply constraints – quantity caps and floors – can apply at a national, portfolio or individual unit level and will affect both dispatch and pricing decisions. The production of steam to supply industry or desalination processes will also impose operational constraints on power plants. There are various alternatives for modelling their impact. The model can accommodate all these options.
5. **Network Constraints**: Electricity travels from power stations to consumers via high and low voltage transmission and distribution networks. Due to constraints and bottlenecks on this network, both within countries as well as between them, the most cost-effective solution to meeting a certain level of electrical demand may in fact not be technically feasible. Despite the robustness incorporated into a lot of electrical equipment, certain events must be avoided. Therefore, in order to limit the possibility of damaging sensitive equipment, more expensive electricity from a power station that has unhindered access to consumers may be used instead of cheaper electricity from a power station on the wrong side of a bottleneck. Transmission constraints are accommodated by defining different dispatch zones. Dispatch across zones is optimised to take user-defined available transfer capacities into account.
6. **New Build and Closure Constraints**: In order to meet a given level of demand and maintain an adequate security standard in the future, new power stations can be built, and existing ones closed, refurbished or repowered. Similar to existing plants, the technical, availability and fuel supply characteristics for all new entrants must be

defined. However, unlike existing plants, we also define the annualised investment cost for each new entrant, taking a view on various financing parameters. The model will then weigh up the benefits from all options offered.

7. **Intelligent Dispatch and Capacity Expansion**: The online or retirement dates and dispatch profiles of plants can be hard-wired but we can also allow the model to make this decision endogenously. Having defined the constraints and options above, the model assesses alternative dispatch and capacity expansion patterns and selects the schedule that minimises the sum of operating and investment costs over the entire forecast horizon, typically 30 years or more.

It is important to recognise that, while the above description of the ECLIPSE™ modelling process illustrates its main features as if it were using some form of stepwise logic, in reality the model takes into account the interdependence between the various economic and non-economic components simultaneously in order to minimise the total cost of meeting demand.

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