SP Angel

Oil & Gas Note

Hibiscus Petroleum*

Starting to Flower

20 July 2015

Zac Phillips

Contents

Prices at 15th July 2015

Exchange Rate:

MYR/$: MYR3.64

Oil & Gas Note

Hibiscus Petroleum*

HIBI MK **BUY**

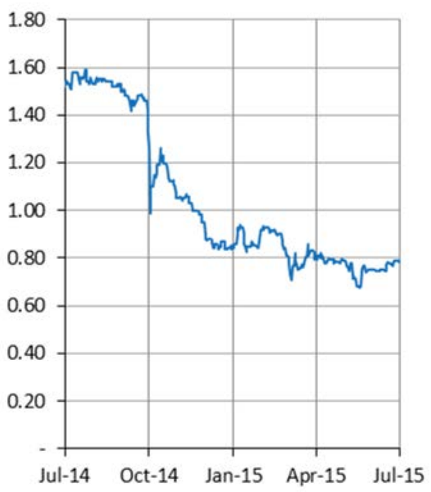
MYR0.79 **MYR1.78**

NAV:	$mm
Core	(17)
Appraisal & Development	85
Exploration	394
Total	**462**
Per Share	MYR1.78
From Current Price	125%

Stock Data

Ticker	HIBI MK
Share Price:	MYR0.75
Market Cap:	MYR732mm
EV:	MYR785mm

Price Chart



Starting to Flower

In Brief

With an active exploration and appraisal programme, as well as potential acquisition of production assets, in line with its balanced approach to its portfolio, Hibiscus is well placed to capitalise on the current operating environment and the eventual upswing in prices when they occur. We initiate coverage with a BUY recommendation and a MYR1.78 Target Price.

Sea Lion Exploration & West Seahorse FID (2H'15) to be a Catalyst

Given the current oil price environment, we see the Sea Lion exploration programme as being a significant influential factor on whether the West Seahorse development is sanctioned in 2015 or at a later stage when the price environment is stronger. If Sea Lion is successful we believe that the assets will be co-developed using joint infrastructure, which will reduce the cost per barrel, hence lower the hurdle rate for development, and prolong both assets' productive lives.

Management Fit for Purpose

The Company's management base is well balanced for its current operating environment and its future plans, especially with the active exploration programme and any pending approval of the development of West Seahorse.

The recent withdrawal from Kitan has proven that the management team has the discipline to adhere to the criteria and framework that it establishes in the negotiation of the definitive agreements, which will be important as the Company continues to seek further assets to add to its portfolio, wherever it is at the exploration/ production cycle.

Valuation $462mm (MYR1.78)

We have valued Hibiscus' assets at $462mm (MYR1.78) using DCF valuation methodology, and adjusting for exploration risk using EMV analysis; the unrisked valuation is $4,969mm (MYR19.50). With an active exploration and appraisal programme underway, we believe that there are numerous near term opportunities for the Company to be revaluated.

We initiate coverage with a BUY recommendation and a MYR1.78 Target Price.

YE June (MYRmm unless stated)	2015E‡	2016E	2017E	2017E
Production (mm boe)	-	-	-	-
Revenues	-	-	-	-
Operating costs	(60.00)	(21.80)	(21.80)	(21.80)
EBITDA	(60.00)	(21.80)	(21.80)	(21.80)
PBT	(60.00)	(19.85)	(27.44)	(37.35)
Net Income	(58.05)	(19.85)	(27.44)	(37.35)
EPS ($)	-	(0.02)	(0.02)	(0.02)
FCFPS ($)	-	(0.17)	(0.21)	(0.03)

Source: SP Angel
‡ - 18 months to June

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Valuation – $462mm (MYR1.78)

We have valued Hibiscus' assets at $462mm (MYR1.78) using DCF valuation methodology and adjusting for risk using EMV analysis; the unrisked valuation is $5,884mm (MYR22.64).

Summary

SP Angel has used discounted cash flow ("DCF") based net asset value ("NAV") as its primary valuation tool as it allows the study of a range of key influential valuation factors on a Company's asset portfolio. However, the market's preeminent role in assessing a Company's worth must also be considered. Consequently, we have valued Hibiscus Petroleum using not only NAV, but also assessed its market "worth" using P_{BEST} Resources market multiples; these assessments are summarised in Table 1 and Figure 1.

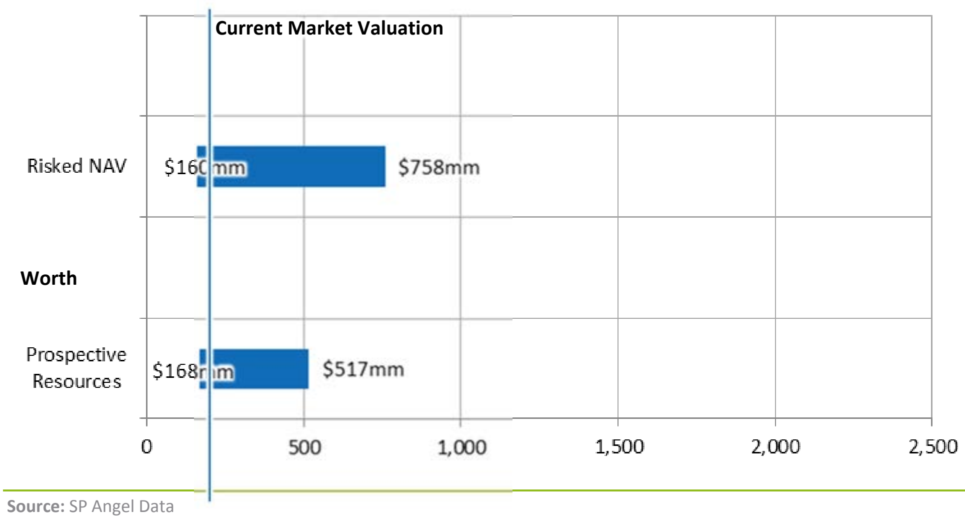
Table 1 – Hibiscus Valuation Summary

Valuation Method	Market average	Hibiscus multiplier	Implied Value ($mm)	Implied Value (MYRshare)
Valuation				
$NAV_{(D)}$ (Page)	-	-	462	1.78
Market "Worth"				
P_{BEST} Prospective Resources (Page)	$0.15/bbl	1,698mm bbl	255	0.98
Overall NAV multiple (Page)	0.43x	$462mm	199	0.76
Average	**-**	**-**	**305**	**1.17**

Source: Bloomberg, Company and SP Angel data

Figure 1 – Tornado Valuation/Worth Summary ($mm)

Hibiscus' valuation across all methodologies



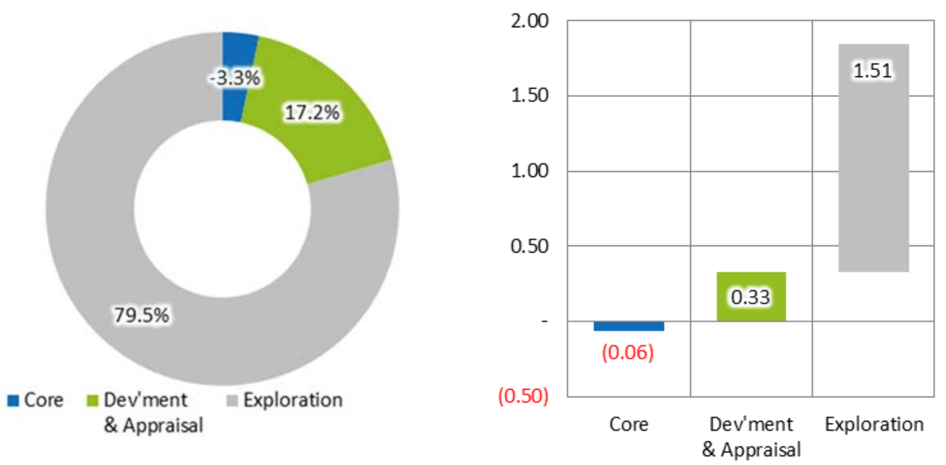
Source: SP Angel Data

NAV Valuation

In valuing Hibiscus we have adopted a discounted cash flow (“DCF”) valuation methodology, the principal valuation technique used by the Oil & Gas industry to value production and appraisal assets. Subsequent to this, where applicable, expected monetary value (“EMV”) was then applied to arrive at a risk adjusted value; more detail on how we undertake valuations is provided in the *Appendix* (*Valuation* of E&P Companies – Page 128). The valuation of the Company’s assets is summarised in Figure 2 and Table 2.

Figure 2 – P_{BEST} NAV Summary

Percentage of Risked NAV | **MYR/share**



Source: Company & SP Angel Data

Table 2 – P_{BEST} $NAV_{(D)}$ Valuation Summary

Field	Hydrocarbons mm boe		NAV ($mm)		NAV ($/boe)		NAV (MYRshare)	
	Unrisked	Risked	Unrisked	Risked	Unrisked	Risked	Unrisked	Risked
Core								
Balance Sheet Items	-	-	(17)	(17)	-	-	(0.06)	(0.06)
Core NAV	**-**	**-**	**(17)**	**(17)**	**-**	**-**	**(0.06)**	**(0.06)**
Appraisal & Development								
Australia	6	5	58	42	9.1	6.6	0.22	0.16
Norway	20	5	115	31	5.9	1.6	0.44	0.12
Oman	6	3	37	12	6.0	1.9	0.14	0.04
Development & App’l NAV	**32**	**13**	**210**	**85**	**6.5**	**2.6**	**0.81**	**0.33**
Exploration§								
Australia	8	4	113	43	13.3	5.1	0.44	0.17
Norway	233	18	1,368	92	5.9	0.4	5.27	0.35
Oman	1,146	123	1,918	158	1.7	0.1	7.38	0.61
UAE	278	25	2,291	101	8.2	0.4	8.81	0.39
Exploration NAV	**1,666**	**171**	**5,690**	**394**	**3.4**	**0.2**	**21.90**	**1.51**
Total NAV	**1,699**	**184**	**5,884**	**462**	**3.5**	**0.3**	**22.64**	**1.78**

Source: Company & SP Angel Data

§ - Excludes contribution from PL544, which is pending the approval of the NPD

Table 3 – Summary of Risking Factors used to Determine NAV

Asset Types	Typical CoS Range	Comment
Exploration	0 – 25%	The Company has an extensive exploration portfolio, with Gemini (Norway) requiring further drilling to fully elucidate the RVD observed prospectivity and a step out exploration well on its VIC/P57 licence, which is targeting the Sea Lion prospect (P_{50} – 11mm bbl). While traditionally exploration prospects have a CoS of between 0 – 25%, Sea Lion has a CoS_G of ~40% given its proximity to an existing discovery and excellent seismic control.
Appraisal	25 – 55%	Following the drilling success in Oman, the Company is now moving in to the appraisal stage, and should be able to pass through in to the production phase quickly should the appraisal and well test proves successful. This has been further bolstered by the pending appraisal of Rolvsnes, which is expected to drill in 2H'15.
Development	55 – 85%	The Company's West Seahorse appraised discovery is still awaiting sanction due to the current price environment. While West Seahorse has a reported 2P of 6.5mm bbl and 2C 1.5mm bbl, we have ascribed the strict SPE PRMS definition of 2P & 2C and classified all recoverable barrels as 2C. We believe that a successful exploration programme on the nearby Sea Lion prospect will enable a development cluster to be established and will mean that West Seahorse is more likely to be developed too.
Production	85 – 100%	The Company has no assets in production. However, once West Seahorse has been approved, we believe that the asset will be quickly migrated in to production.

Source: SP Angel data

Peer Group Market Worth

In conducting peer group valuation, SP Angel has looked at two differing methods, namely: (i) per barrel of Contingent & Prospective Resources basis; and (ii) net asset value multiple basis. The NAV multiple valuation is estimated by using the total risked NAV, which in the case of Hibiscus includes the consolidation of the risk adjusted appraisal NAV. Using these methods implies an average valuation of $227mm (MYR0.87/share) (Table 4), some 10% below the current market value.

Table 4 – Hibiscus Peer Group Summary

Valuation Metric	Market average	Hibiscus multiplier	Implied Value ($mm)	Implied Value (MYR/share)
P_{BEST} Contingent & Prospective Resources	$0.15/bbl	1,699mm bbl	255	0.98
NAV multiple	0.43x	$462mm	199	0.76
Average	-	-	**227**	**0.87**

Source: Bloomberg, Company and SP Angel data

Per P_{BEST} Barrel of Contingent & Prospective Resources

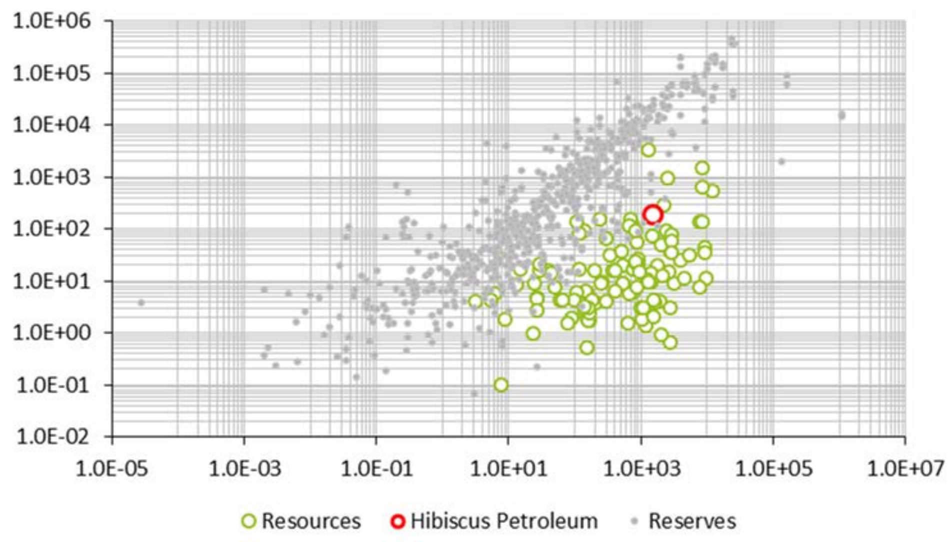
SP Angel has conducted a review of E&P companies worldwide, limiting its comparison to those with Prospective Resources; assuming that the companies that have been studied have reported their respective resources according to SPE PRMS guidelines.

As can be seen in Figure 3, Hibiscus is trading at a discount to the prevailing risk adjusted valuations for Prospective Resources, as implied by the fact Hibiscus' valuation is below the market average line (in red).

We have averaged the data for those companies by the key international exchanges, and while this data suggests that P_{BEST} barrels trade at value in excess of $4.0, eliminating valuations above $0.50/$P_{BEST}$ bbl results in a value of $0.15/$P_{BEST}$ bbl, which we believe to be more representative of a fair market valuation.

Figure 3 – EV per P_{BEST} Barrel of Prospective Resources Market Worth

Variation in EV ($mm – Vertical Axis) with P_{BEST} Barrel of Prospective Resources (mm boe – Horizontal Axis)



Source: Bloomberg & SP Angel data

On this basis, and using Hibiscus' P_{BEST} unrisked Resources of 1,699mm bbl, implies a valuation of $255mm (MYR0.98/share), above of the current market valuation of ~$193mm. While we accept the exploration programme carries risks, we believe that the fact that the assets are based onshore UK deserves a higher premium that the average.

Consequently, while providing us with comfort as to the current valuation, we believe that the current market valuation is too great a discount to the potential within the Company's asset base.

NAV Multiple

All Oil & Gas companies trade at a discount to the DCF derived net asset value ("NAV"). Per the basis of this comparison SPA utilises the total NAV, which includes the risk adjusted NAV is for exploration and appraisal assets.

If we look at the average NAV trading multiple for companies that SP Angel Maintains NAV valuations on, the average NAV multiple is 0.43x, which given Hibiscus' $NAV_{(D)}$ of $462mm, implies a value of $199mm, or MYR0.76, which is in line with the current valuation.

Sensitivity Analysis

In assessing the value of the Company using DCF valuation, we have recognised all of the key parameters that we believe impact the valuation, not only the oil price but others such as: (i) discount rate; (ii) SPE PRMS Assessment Category; and (iii) the Technical to Commercial Success Rate; the results are summarised in Table 5.

Table 5 – Summary of Sensitivity Analysis

Sensitivity Analysis	Comment	Base Case	Page
SPE PRMS Assessment Category	As would be expected there is an increasing value with increasing volumetrics.	P_{BEST}	8
Oil & Gas Prices	Given the fact that the Company's portfolio is effective liquids based, it is not surprising that the variation in oil price has a more profound effect on the overall valuation than gas prices.	SPA Curve	9
Discount Rate	Given the fact that the assets are based in stable countries and the Company's management is well able to effectively deliver its development programme, we consider the base discount rate of 10% to be a fair reflection of the business.	10%	11
Technical to Commercial Success Rate	Valuation increases proportionally with higher technical to commercial success rates.	50%	12

Source: SPA Data

SPE PRMS Assessment Category

Given the probabilistic nature of assessing potentially recoverable hydrocarbons from an undrilled prospect, there will always be a range of uncertainty. The SPE PRMS system provides guidance as how best to address this range of uncertainty; we discuss the SPE PRMS system in greater detail in the *SPE Petroleum Resources Classification Framework* section (Page 135).

We have assessed the Company's value over the range ascribed by the SPE PRMS system, namely P_{90}, P_{50} and P_{10}, as well as P_{BEST}, which is a measure of the volumetrics based on the skewness of the standard SPE PRMS probability distribution. We summarise our estimates in Table 6.

Table 6 – Variation in $NAV_{(D)}$ with SPE PRMS Assessment Category

	Hydrocarbons		NAV					
Scenario	mm boe		($mm)		($/boe)		(MYR/share)	
	Unrisked	Risked	Unrisked	Risked	Unrisked	Risked	Unrisked	Risked
P_{90}	886	96	3,091	169	3.49	0.19	11.89	0.65
P_{50}	1,541	165	5,291	362	3.43	0.23	20.36	1.39
P_{BEST}	1,699	184	5,884	462	3.46	0.27	22.64	1.78
P_{10}	2,721	291	9,177	767	3.37	0.28	35.31	2.95

Source: SP Angel Data
NOTE: Base Case Assumptions used for all other parameters

It is no surprise that there is an increase in value with increasing Prospective Resources. This is attributable to 2 main factors: (i) that the ultimate Reserve base that will be produced from is larger, which in turn precipitates a higher NPV in dollar terms; and (ii) the proportion of investment that is required, on a per barrel basis, to bring an asset into production falls significantly with increasing size, i.e. there are economies of scale to be had with larger projects.

Oil & Gas Prices

As well as analysing the impact of a number of price decks (flat nominal prices), we also provide three representative price profiles; these are described in Table 7 and illustrated in Figure 4.

Table 7 – Oil & Gas Price Profiles

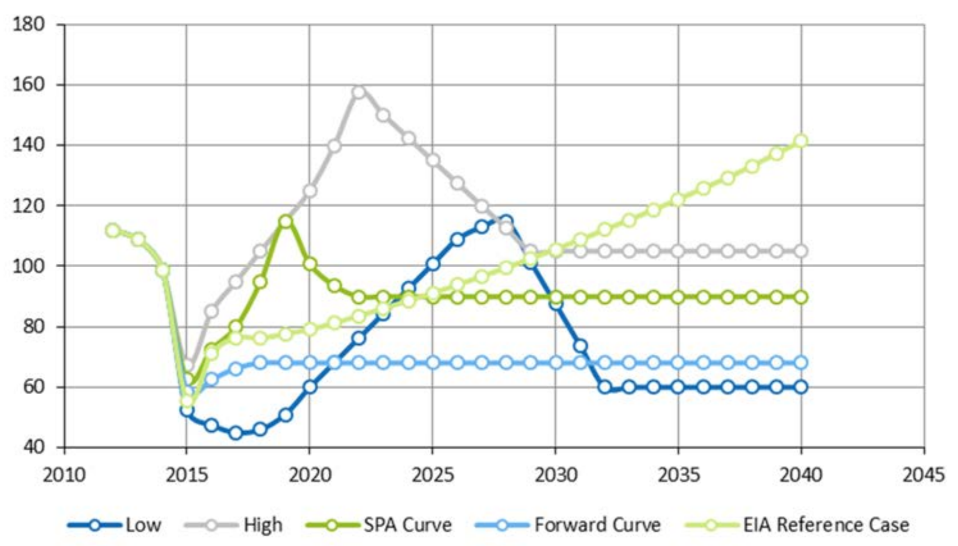
Scenario	Oil Price	Gas Price
SPA Curve (or Base Case):	The current oil price environment will persist for the near term, but that beyond the summer it will start to improve, ending the year in the region of $75/bbl, before responding to the prevailing supply side environment. In the medium to longer term, and depending on GDP, we believe that the supply side of the equation will become more acute, and continue to drive prices up, peaking in 2019 at ~125/bbl	Our estimate for the Henry Hub ("HH") price is expected to trade at $4.8/mcf in 2014 rising to $5.0/mcf in 2015 and remaining at $5.3/mcf from 2017 onwards. Our estimate for the NBP we have based it on the HH price, For European prices, we have assumed that NBP price trades at the historic 5-year premium to the prevailing Henry Hub price.
Forward Curve Nominal:	Forward oil prices provided by Bloomberg from the International Commodity Exchange ("ICE"), London, as of March 2015, which rises from a current level of $54.2/bbl to $70.6/bbl in December 2017. This oil price sensitivity then assumes flat nominal oil prices thereafter.	Forward gas prices were provided by Bloomberg, with NBP pricing by the IPE (as at June 2015) trading at between 43p and 52p (per therm) over the period to June 2018 dependent on season. Henry Hub (NYMEX as at June 2015) shows that gas prices trade between $2.77 – 3.66/mcf over the period to June 2018
EIA Reference Case§	Brent spot oil price averages $96 per barrel in 2015. After 2015, the Brent price increases, reaching $100 per barrel in 2020 and onwards to $150/bbl in 2040.	Henry Hub price averages $3.70/mcf in 2015. After 2015, the Brent price increases, reaching $7.90.mcf in 2040. For European prices, we have assumed that NBP price trades at the historic 5-year premium to the prevailing Henry Hub price.

Source: Bloomberg & SP Angel Data

§ - The EIA reference case is taken from the Energy Information Administration's ("EIA") Annual Energy Outlook 2014

Figure 4 – Oil Price Profiles

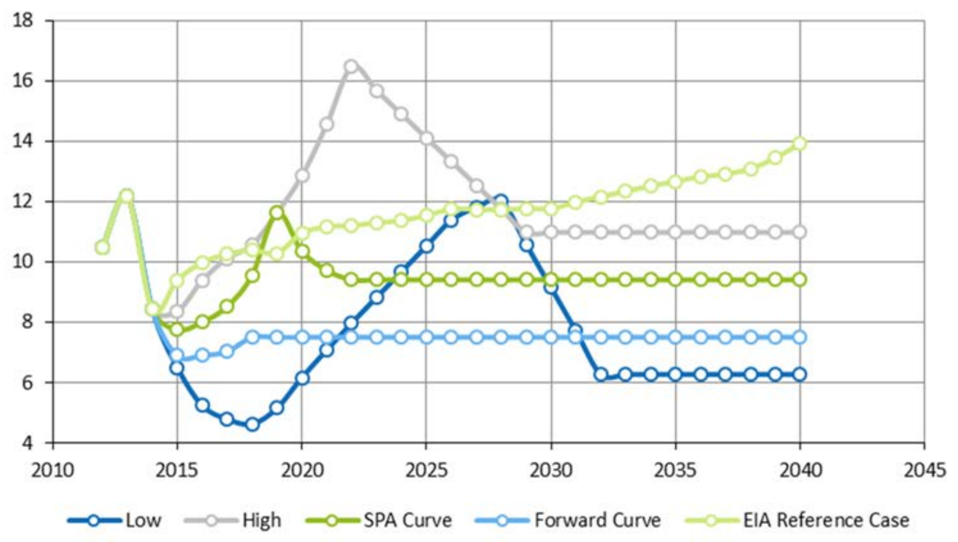
$/bbl



Source: Bloomberg IEA & SP Angel Data

Figure 5 – Gas Price Profiles

NBP ($/mcf)



Source: Bloomberg & SP Angel Data

The impact that variations in both the gas price and oil price have on Risked $NAV_{(D)}$ is summarised in Table 8 (in $mm) and Table 9 (in MYR/share). Table 8 and Table 9 highlight that the value of the Company is more sensitive to changes in the oil price than the gas price. This is to be expected, given that the production portfolio is dominated by future oil production, opposed to gas.

Table 8 – Impact of Variation in Oil & Gas Price on $NAV_{(D)}$ ($mm)

Oil Price ($/bbl)	Gas Price ($/mcf): 4.0	4.5	Low	SPA Curve	High	Forward Curve	EIA Reference Case
55	43	44	46	49	61	45	53
65	95	96	98	102	115	96	107
Low	360	361	366	370	384	362	376
SPA Curve	452	453	458	462	476	454	468
High	889	891	896	901	915	892	906
Forward Curve	130	131	134	138	152	132	143
EIA Reference Case	487	488	493	497	511	489	503

Source: Bloomberg & SP Angel Data
NOTE: Base Case Assumptions used for all other parameters

Table 9 – Impact of Variation in Oil & Gas Price on $NAV_{(D)}$ (MYR/share)

Oil Price ($/bbl)	Gas Price ($/mcf): 4.0	4.5	Low	SPA Curve	High	Forward Curve	EIA Reference Case
55	0.17	0.17	0.18	0.19	0.23	0.17	0.20
65	0.36	0.37	0.38	0.39	0.44	0.37	0.41
Low	1.38	1.39	1.41	1.42	1.48	1.39	1.45
SPA Curve	1.74	1.74	1.76	1.78	1.83	1.75	1.80
High	3.42	3.43	3.45	3.47	3.52	3.43	3.49
Forward Curve	0.50	0.50	0.51	0.53	0.58	0.51	0.55
EIA Reference Case	1.87	1.88	1.90	1.91	1.97	1.88	1.94

Source: Bloomberg & SP Angel Data
NOTE: Base Case Assumptions used for all other parameters

Discount Rate

In assessing the value of an oil company's asset we start with a basic discount rate of 10% which is the typical discount rate adopted by the O&G industry to determine the unrisked economic value of the Oil & Gas in the ground. In determining an overall risked $NAV_{(D)}$, however, we also need to take account of two additional risk premia by adding to the basic discount rate an assessment of: (i) Geopolitical Risk; and (ii) Business Execution Risk.

The assessment of Geopolitical and Business Execution Risks are difficult to quantify as it is subjective and varies from person to person and at what point in time it is applied. It is a subjective assessment of a management's ability to execute its business plan effectively in the face of operational, political, environmental and other exogenous factors. For example, an experienced management with a solid track record in benign onshore location near infrastructure will have a lower risk premia than an identical asset operated by a less experienced management, in a country with a hostile government in an offshore setting where there is no infrastructure. The overall discount rate is a product of the base discount rate, Geopolitical Risk and Business Execution Risk. Our estimate of these risks, and our comments, are provided in Table 10.

Table 10 – Base Case Summary of Geopolitical Risk

Country	Value	Comment
Australia	0.35%	The country has a long history of petroleum exploitation, which has declined in recent times. However, recent changes to the fiscal regime have provided significant headwinds, especially when compared globally.
Norway	0.25%	The strong competitiveness of the Norwegian economy is built on openness and transparency, with policies that support dynamic trade and investment, and the legal framework is among the world's strongest, providing effective protection of property rights. The tax rebate of 78% of exploration investment makes Norway an attractive destination for Oil & Gas investment.
Oman	0.25%	Despite a benign operating environment for Oil & Gas companies, the economy remains highly leveraged to Oil & Gas revenues. In response to fast growth in household indebtedness, the Central Bank reduced the ceiling on personal interest loans from 8% to 7%, lowered mortgage rates, capped the percentage of consumer loans at 50% of borrower's salaries for personal loans and 60% for housing loans, and limited maximum repayment terms to 10 and 25 years respectively.
United Arab Emirates	0.25%	The political environment is stable and the UAE maintains contract integrity. The emirates, especially Ras Al Khaimah and Sharjah, are starting to make the fiscal terms more attractive in order to effectively compete for investment globally.

Source: SPA data

Table 11 – Base Case Summary

Risk Parameter	Value	Comment
Geopolitical Risk	Variable	See Table 10
Business Risk	-	Company is currently well disposed to manage the current programme, given the Company's point in the exploration and appraisal cycle.
Base Discount Rate	10.00%	Convention widely used by the O&G industry to determine the unrisked economic value of the Oil & Gas in the ground.
Overall Discount Rate	**≥10.00%**	-

Source: SPA estimates

Given the impact that discount rate has on value, we have provided a ready reckoner (Table 12 and Table 13) which details the impact of the variation in the contribution that the component risk premia or discounts have on the base case Risked NAV.

Table 12 – Impact of Variation in Risk Premium on $NAV_{(D)}$ ($mm)

Geopolitical Risk Premium	Business Risk Premium: (3.0%)	(2.0%)	(1.0%)	-	1.0%	2.0%	3.0%
(3.0%)	1,328	1,129	956	806	675	561	462
(2.0%)	1,129	956	806	675	561	462	376
(1.0%)	956	806	675	561	462	376	301
-	806	675	561	462	376	301	237
1.0%	675	561	462	376	301	237	185
2.0%	561	462	376	301	237	185	143
3.0%	462	376	301	237	185	143	122

Source: SP Angel estimates
NOTE: Base Case Assumptions used for all other parameters

Table 13 – Impact of Variation in Risk Premium on $NAV_{(D)}$ (MYR/share)

Geopolitical Risk Premium	Business Risk Premium: (3.0%)	(2.0%)	(1.0%)	-	1.0%	2.0%	3.0%
(3.0%)	5.11	4.34	3.68	3.10	2.60	2.16	1.78
(2.0%)	4.34	3.68	3.10	2.60	2.16	1.78	1.45
(1.0%)	3.68	3.10	2.60	2.16	1.78	1.45	1.16
-	3.10	2.60	2.16	1.78	1.45	1.16	0.91
1.0%	2.60	2.16	1.78	1.45	1.16	0.91	0.71
2.0%	2.16	1.78	1.45	1.16	0.91	0.71	0.55
3.0%	1.78	1.45	1.16	0.91	0.71	0.55	0.47

Source: SP Angel estimates
NOTE: Base Case Assumptions used for all other parameters

Technical to Commercial Success Rate

Once a hydrocarbon accumulation is intersected there is still a need to appraise the discovery to ascertain individual reservoir and hydrocarbon production criteria. Whether a discovery ultimately becomes commercial is dependent on a number of key factors, notably (i) hydrocarbon (oil or gas, or combination of both); (ii) recoverable volume; (iii) drainage per well; (iv) drive (expansion, gas, for support, etc.); and (iii) production rate.

In addition to these subsurface specific factors, there is also a need to take into account certain topside factors, such as whether the asset is onshore or offshore, whether there is a readily available market for the hydrocarbon produced, distance to market and more importantly a means to get it there.

In respect of the Company's assets, however, we believe that the application of the Rex Virtual Drilling ("RVD") has a beneficial impact on the technical to commercial success rate, based on the results of the trials that have been completed to date.

The RVD technology provides the explorationist with positive affirmation, as to whether hydrocarbons are present or absent, as well as confidence in that result. As a result, strong positive responses are more likely to be drilled than weaker responses, which in turn lead to higher success rates overall.

Nevertheless, we recognise that this is a judgement based on our experience and empirical data based on exploration worldwide, and as such may be too conservative. Consequently, we have assessed the impact that varying the technical to commercial chance of success has on the overall valuation of the Company; this analysis is summarised in Table 14 ($mm) and Table 15 (MYR/share).

Table 14 – Impact of Variation in Oil Price and COS$_C$ on NAV$_{(D)}$ ($mm)

Technical to Commercial Success rate (CoS$_C$)	Oil Price ($/bbl)/Price Scenario: Low	SPA Curve	High	Forward Curve	EIA Reference Case
100%	963	1,098	1,935	473	1,189
85%	784	906	1,624	369	981
70%	606	715	1,314	266	772
60%	487	588	1,107	200	634
50%	370	462	901	138	497
40%	258	339	694	81	363
35%	205	278	592	57	297

Source: SPA Data

Table 15 - Impact of Variation in Oil Price and COS$_C$ on NAV$_{(D)}$ (MYR/share)

Technical to Commercial Success rate (CoS$_C$)	Oil Price ($/bbl)/Price Scenario: Low	SPA Curve	High	Forward Curve	EIA Reference Case
100.0%	3.70	4.22	7.45	1.82	4.57
85.0%	3.02	3.49	6.25	1.42	3.77
70.0%	2.33	2.75	5.06	1.02	2.97
60.0%	1.87	2.26	4.26	0.77	2.44
50.0%	1.42	1.78	3.47	0.53	1.91
40.0%	0.99	1.30	2.67	0.31	1.40
35.0%	0.79	1.07	2.28	0.22	1.14

Source: SPA Data

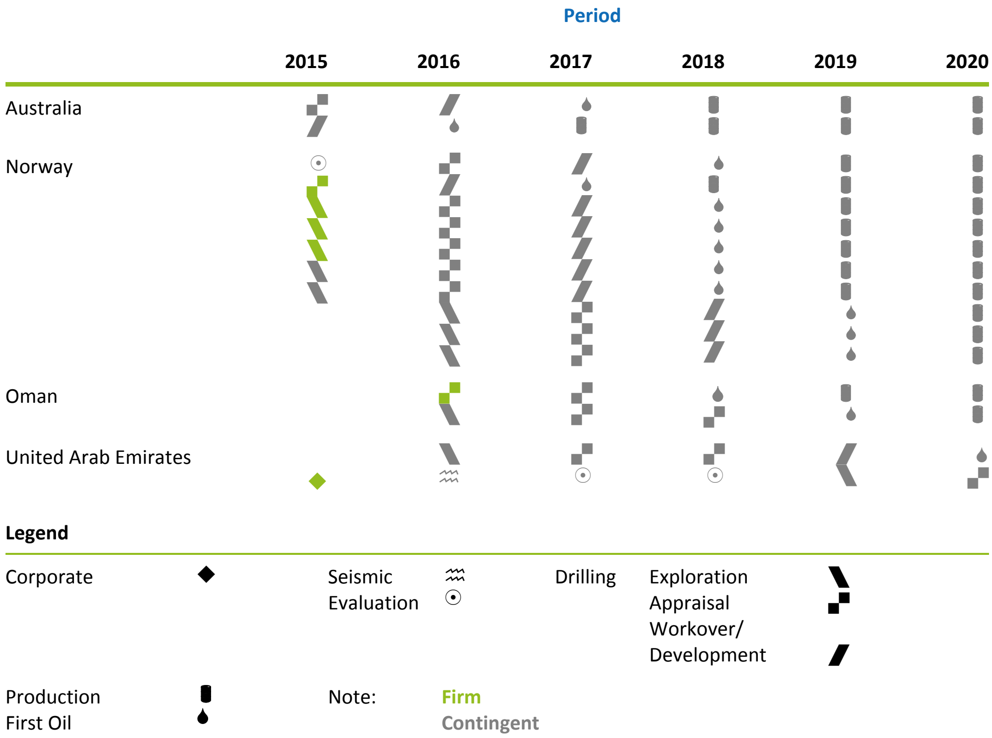
Production, Work Programme & Cash Flow

Hibiscus has an active work programme underway, and with a number of appraisal and development projects in the portfolio, the outlook for future cash generation is solid.

Work Programme

The Company has an active work programme over the next 12 to 18 months, constituted of a number of firm exploration wells in Australia, the UAE and principally Norway. Hibiscus also has to appraise is Omani discovery (GA South) and make a decision on whether to sanction the development of its West Seahorse asset in Australia. Our outlook for the Company's work programme is illustrated in Figure 6.

Figure 6 – SP Angel Estimate Work Programme Estimate



Source: Company data & SPA estimates

Production

The Company does not currently have any production, although it has exposure to West Seahorse ("WSH"), which is currently at the end of its appraisal programme, and awaiting sanction.

We have not consolidated any contribution from WSH due to the fact that there is uncertainty (in our minds at least) over whether the Company will elect to sanction the West Seahorse development programme before the end of the year (calendar 2015). We do however consolidate a risked value for West Seahorse in our overall asset valuation.

Furthermore, the proposed testing programme in Oman, currently scheduled to commence in 2016, our estimate is for some time in 1H, and will consist initially of a suite of standard flow tests, followed by an extended well test, and although not technically first oil, this will see the Company generating all-important revenues during this testing phase. The Company will also undertake a further seismic acquisition programme to elucidate the mechanisms and structure within the licence.

Despite being located offshore, which generally has an average development time of 2 years, we believe that the use of an extended well test and an early production facility ("EPF") at the appraisal stage will mean that the Company, depending on test results, could potentially declare commerciality within a short period while continuously producing using the in place equipment and infrastructure.

Nevertheless, we estimate that first oil (sustained production using permanent production facilities) will flow in 2018. However, we believe that the relatively high operating costs of EPF equipment, due to rental and tolling costs, will mean that Hibiscus should look to commission permanent production facilities contemporaneously with production through the EPF.

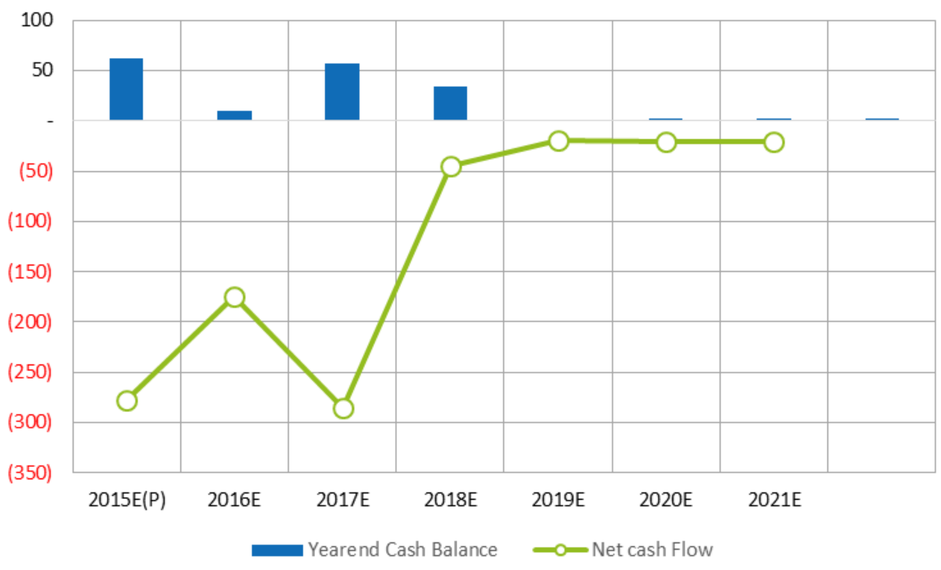
Cash Flow

Based on our outlook for the work programme and cost estimates, we believe that Hibiscus will require further funding, the extent of which will be determined by the work programme and any partnering Hibiscus elects to undertake.

Currently the Company has no cash flow and needs to fund its future work programme; our estimates for the free cash flow (operating cash flow less contractual costs) is illustrated in Figure 7. However, we also believe that the Company will pursue selected acquisition that will bring near term cash flow opportunities.

Figure 7 – Cash Flow

MYRmm



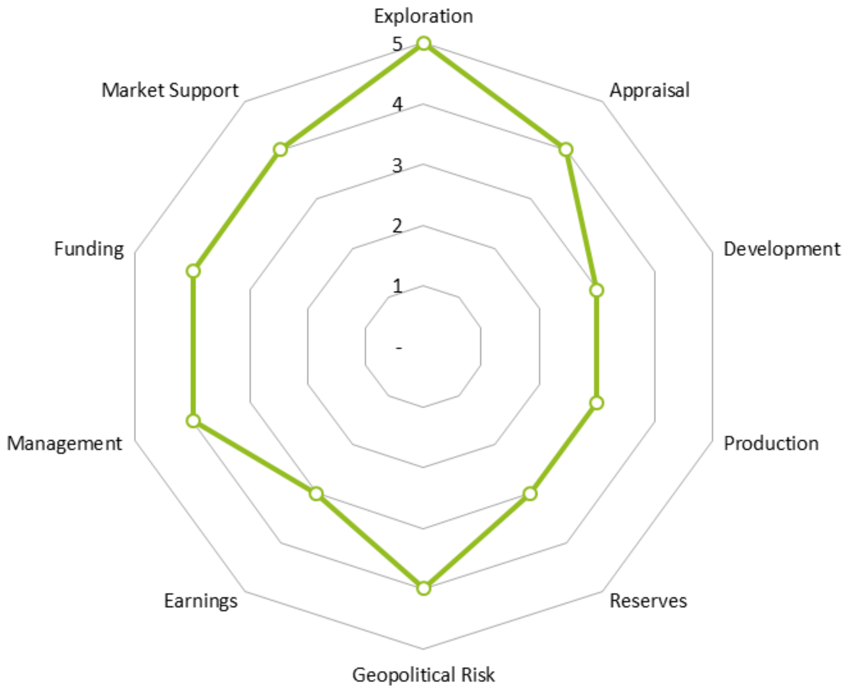
Source: SPA estimates
NOTE: the Company has no assets in production. These estimates also exclude any contribution from the yet to be sanctioned West Sea Horse.

Our estimates of the Company's cash flow are summarised in *SP Angel Earnings Summary* (Page 17).

SP Angel Company Scorecard

Figure 8 – SP Angel Scorecard

5-Star Rating



Category	5-Star Rating	Comment
Exploration	★★★★★	The Company has a diverse exploration portfolio, with a wide range of geographies, locations and play types. With Sea Lion spudding 2H'15, and an active exploration programme, including Haribo (underway) in Norway, the Company's exploration portfolio remains buoyant.
Appraisal	★★★★☆	Oman and Rolvsnes (added to the portfolio in March 2013) are key appraisal asset in its portfolio. Drilling in the UAE is within areas of known production, that while the risks associated with these assets may be considered appraisal type risk, we exclude these from this category.
Development	★★★☆☆	The Company's West Seahorse ("WSH") appraised discovery (2C ~8.0mm bbl) is still awaiting sanction due to the current price environment. Exploration success on Sea Lion will enable a development cluster to be established and will mean that West Seahorse is more likely to be developed too.
Production	★★★☆☆	While the Company has no assets in production, once sanctioned. WSH will be quickly migrated in to production.
Reserves	★★★☆☆	While Hibiscus does not have any booked reserves currently, the final investment decision ("FID") on WSH will quickly migrate Contingent Resources into Reserves.
Geopolitical risk	★★★★☆	The Company's geographical footprint resides in regions supportive of Oil & Gas investment and a history of equitable treatment in law.
Earnings	★★★☆☆	Once commissioned, we do not believe that WSH will quickly deliver cash flow to the Company.
Management	★★★★☆	The Company has a well-balanced management team with the requisite skill base to deliver a solid exploration, appraisal and development programme.
Funding	★★★★☆	While the current programme is met, we believe that any acceleration in the programme, or additional elements will require funding, which will be met in the first instance by additional equity, and in the case of the Australian development assets, debt too.
Market Support	★★★★☆	While the shares continue to trade below fair value, we believe that there remains appetite from investors.
Overall	★★★★☆	**The Company's current exploration and appraisal programme is significant, and with further material upside possible the Company is well positioned to take advantage of the current investment environment.**

Source: SP Angel Data

SP Angel Earnings Summary

Income Statement

YE Dec (MYRmm unless stated)	2015EP‡	2016E	2017E	2018E
Gas (mm cfpd)	-	-	-	-
Oil (m bpd)	-	-	-	-
Total Production (m boepd)	**-**	**-**	**-**	**-**
Revenue	-	-	-	-
Cost of Sales	-	-	-	-
Net Revenues	**-**	**-**	**-**	**-**
Operating Costs	(60.00)	(21.80)	(21.80)	(21.80)
Exploration Costs	-	-	-	-
EBITDA	**(60.00)**	**(21.80)**	**(21.80)**	**(21.80)**
DD&A	-	(7.76)	(14.87)	(15.58)
Exceptional Items	-	-	-	-
Other Items	-	9.30	9.30	-
EBIT	**(60.00)**	**(20.26)**	**(27.37)**	**(37.38)**
Net Interest	-	0.64	(0.10)	0.04
EBT	**-**	**(19.62)**	**(27.48)**	**(37.34)**
Tax	1.95	-	-	-
Net Income	**(58.05)**	**(19.62)**	**(27.48)**	**(37.34)**
Retained Income	**(58.05)**	**(19.62)**	**(27.48)**	**(37.34)**

Source: SP Angel

Statement of Financial Worth

YE Dec (MYRmm unless stated)	2015EP‡	2016E	2017E	2018E
Intangible Assets	-	194.97	255.03	259.12
Tangible Assets	-	225.09	426.44	432.42
Investments	-	260.65	284.67	286.31
Other	-	-	-	-
Fixed Assets	**-**	**680.71**	**966.14**	**977.86**
Cash	10.00	67.36	32.79	1.83
Assets Held for Sale	-	-	-	-
Receivables	-	7.44	6.70	6.03
Other	-	1.24	1.24	1.24
Current Assets	**10.00**	**76.04**	**40.73**	**9.10**
Total Assets	**10.00**	**756.75**	**1006.86**	**986.96**
Payables	-	(11.05)	(8.84)	(7.07)
Finance Debt	-	32.09	-	-
Provisions	-	-	-	-
Other	-	(64.22)	(0.04)	(0.04)
Liabilities	**10.00**	**(43.18)**	**(8.88)**	**(7.11)**
Net Book Value	**10.00**	**713.58**	**997.99**	**979.85**

Source: SP Angel

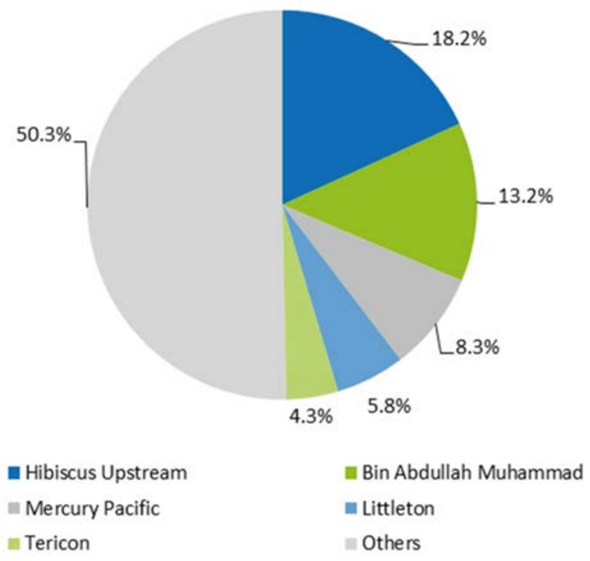
Cash Flow

YE Dec (MYRmm unless stated)	2015EP‡	2016E	2017E	2018E
Operations	-	(20.26)	(27.37)	(37.38)
Working Cap	-	74.78	2.95	2.44
Other	-	7.76	14.87	15.58
Operating cash flow	**-**	**62.27**	**(9.55)**	**(19.36)**
Servicing of Finance	-	0.64	(0.10)	0.04
Net Cash Income	**-**	**62.91**	**(9.65)**	**(19.32)**
Net Cap Ex	-	(237.84)	(276.28)	(25.66)
Net Acquisitions	-	-	-	-
Net Divestments	-	-	-	-
Net Cash Flow	**-**	**(237.84)**	**(276.28)**	**(25.66)**
Issue of Shares	-	272.07	251.35	14.03
Net Movement in Debt	-	31.87	(32.09)	-
Other	-	-	32.09	-
Net financing	**-**	**303.94**	**251.35**	**14.03**
Net Cash Flow	**-**	**129.02**	**(34.57)**	**(30.96)**
Net Cash (Debt)	**10.00**	**99.45**	**32.79**	**1.83**

Source: SP Angel

Ownership

Top 5 Shareholders



Source: Bloomberg & SP Angel data

‡ - 18 months to June 2015

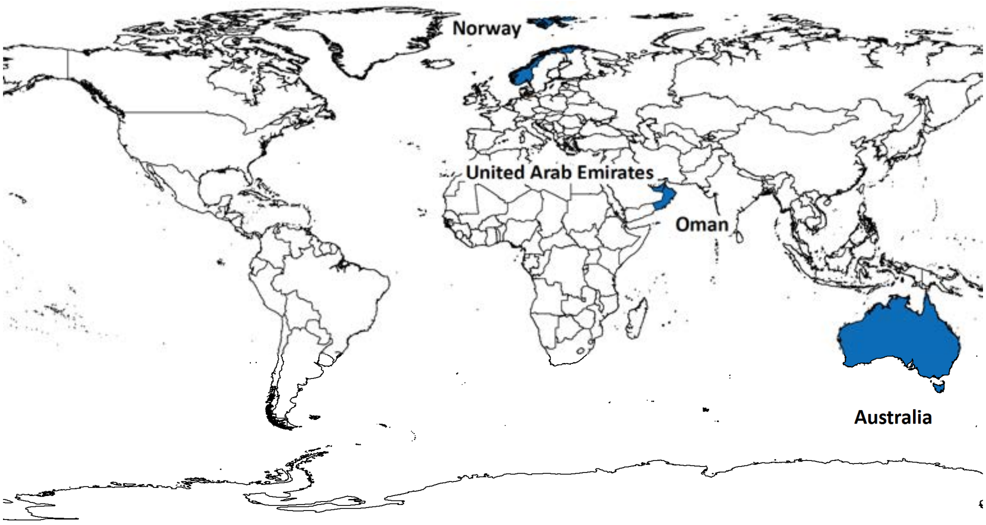
Licence Interests

Hibiscus has a wide portfolio of interests, operating in a number of significant hydrocarbon provinces, covering all stages of the exploration/appraisal/development cycle.

Hibiscus has an interest in 22 licences in 4 countries, namely (i) Australia; (ii) Norway; (iii) Oman; and (iv) the United Arab Emirates. The general location of the assets is illustrated in Figure 9, and summarised in Table 16.

Figure 9 – Countries of Operation

Countries that Hibiscus has interest



Source: ESRI & SPA data

Table 16 – Asset Summary

Country	Licences	Summary	Page
Australia	2	Offshore licences VIC/L31 and VIC/P57	18
Norway	16	Located offshore, in the 3 principal operating areas, namely: the (i) North Sea area; (ii) Norwegian Sea area; and (iii) Barents Sea area.	20
Oman	1	Block 50 offshore Oman, in the region of Masirah Island.	24
United Arab Emirates	3	Two offshore licence areas and one onshore licence area. Mixture of exploration and appraisal assets. Onshore licence area at early exploration stage.	25

Source: Company & SPA data

Australia

Hibiscus' Australian exposure currently stands at 2 licences (Table 17 & Figure 10) both located offshore in the Gippsland Basin. The first licence, VIC/L31, contains the West Sea Horse discovery, while VIC/P57 is a pre-emptive acreage position which covers the regional prospectivity already identified.

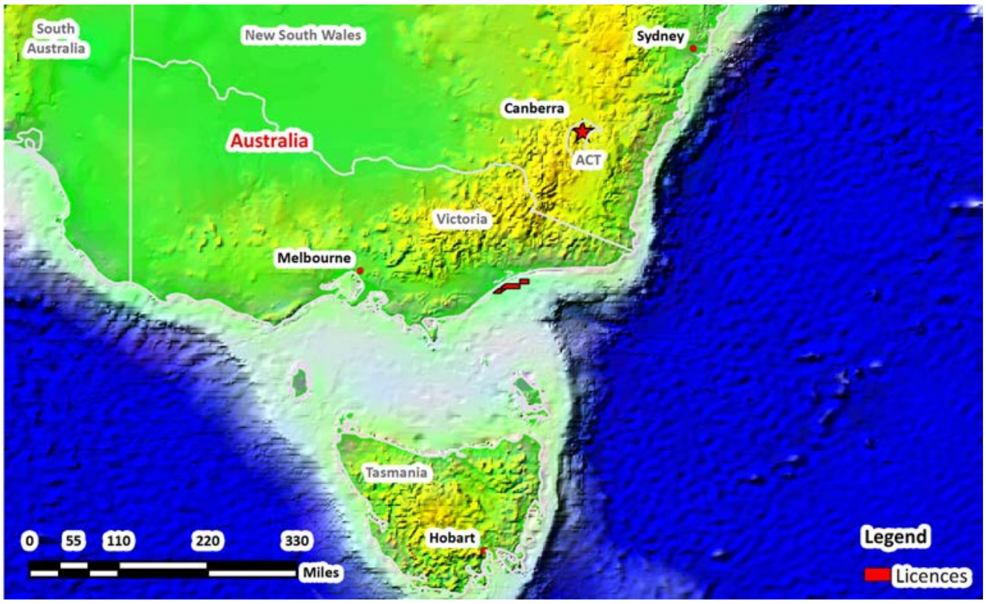
Table 17 – Licence Working Interest Summary – Australia

Licence	Net Working Interest	Area Summary
VIC/L31	100%	Licence block lies some 14km offshore Victoria. The company has recently acquired an undivided working interest in the licence and contains the West Seahorse discovery (2C – 8.0mm bbl).
VIC/P57	75%§	Licence block lies some ~7km offshore Victoria, and is contiguous with the VICL/31 licence. The licence contains the Sea Lion prospect which will be drilled in the second quarter of 2015.

Source: Company, NOPTA, ESRI & SPA data
§ - Pending transfer of 20% stake from HiRex JV to Hibiscus Petroleum

Figure 10 – Licences Australia

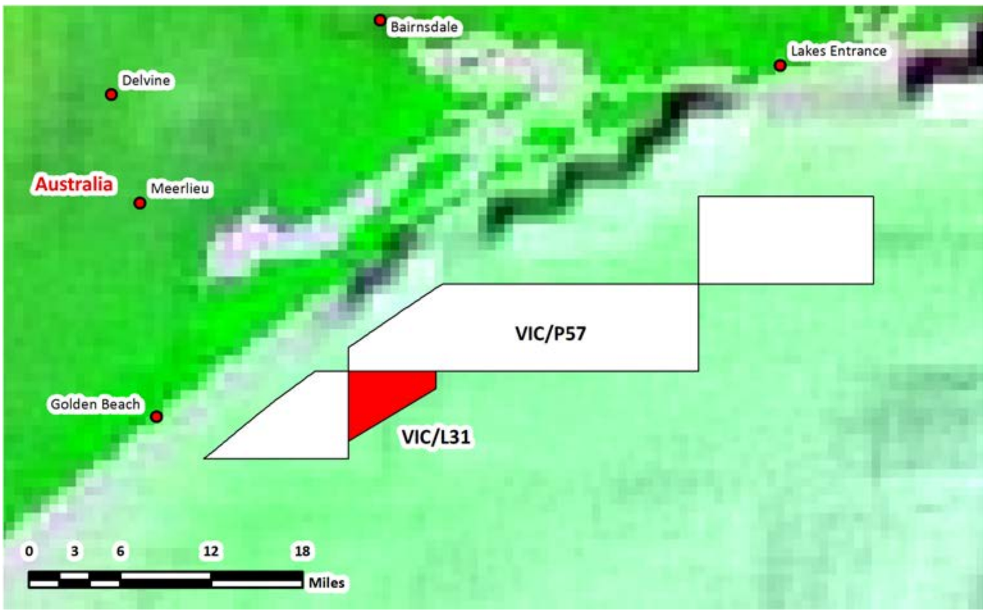
Overview of Hibiscus' Australia Licences



Source: NOPTA, ESRI & SPA data

Figure 11 – Victoria Licence

Hibiscus Licence Areas



Source: NOPTA, ESRI & SPA data

Norway

Hibiscus has 16 licence interests (Table 16), in each of Norway's three general offshore licence areas (Figure 12) held via its 35% interest in Lime Petroleum, namely: (i) the Barents Sea area, which is located off Norway's northern shore; (ii) the Norwegian Sea area, which is generally described as being between Trondheim and Tromso; and (iii) the North Sea area. The licences are illustrated in Figure 13.

Table 18 – Licence Working Interest Summary – Norway

Licence	Net Working Interest‡	Area Summary
PL338C	30.0%	Located ~190miles west of Stavanger in the North Sea (Figure 14). Water depths average 100m in this area.
PL498 & PL498B	25.0%	Located ~180miles west south west offshore Stavanger in the North Sea (Figure 14). Water depths average 100m in this area.
PL503, 503B & 503C	12.5%	Located ~120miles west offshore Stavanger in the North Sea (Figure 14). Water depths average 100m in this area.
PL544§	30.0%	Located ~120miles west offshore Stavanger in the North Sea (Figure 14). Water depths average 100m in this area.
PL591, PL591B & PL591C	25.0%	Located ~179miles north west west of Steinker in the Norwegian Sea (Figure 15). Water depths can exceed 2,000m in this area, but are generally believed to be >800m in the area of PL762 We have excluded these assets from the valuation due to lack of available information.
PL616	15.0%	Located ~250miles south south west offshore Stavanger in the North Sea (Figure 14). Water depths average 100m in this area.
PL707	10.0%	Located ~90miles north of Vadso in the Barents Sea (Figure 16). Water depths average 240m in this area.
PL708	10.0%	Located ~110miles north north west of Vadso in the Barents Sea (Figure 16). Water depths average 240m in this area.
PL762	20.0%	Located ~186miles north north west of Steinker in the Norwegian Sea (Figure 15). Water depths can exceed 2,000m in this area, but are generally believed to be >800m in the area of PL762
PL769	20.0%	Located off the central northern coast of Norway in the Barents Sea (Figure 17) to the east of the PL707 licences. Water depths average 240m in this area.
PL770	20.0%	Located off the central northern coast of Norway in the Barents Sea (Figure 17) to the east of the PL707 licences. Water depths average 240m in this area.

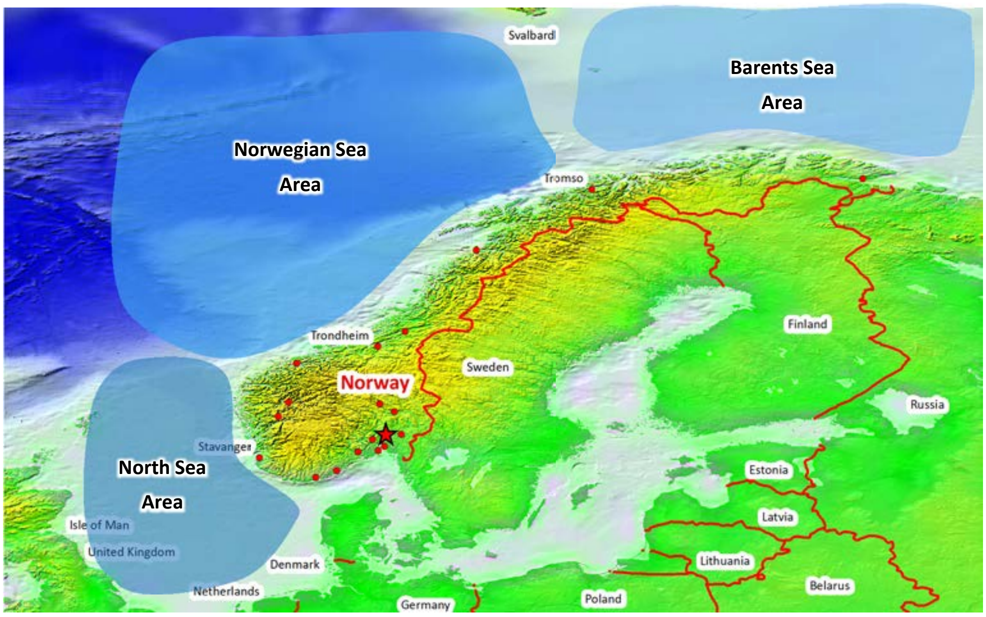
Source: Company, NPD, ESRI & SPA data

‡ - interest as provided by the NPD. The interest net to Hibiscus is 35% of the above.

§ - Pending approval by the Norwegian Petroleum Directorate ("NPD"). Not included in valuation

Figure 12 – Norwegian General Operating Areas

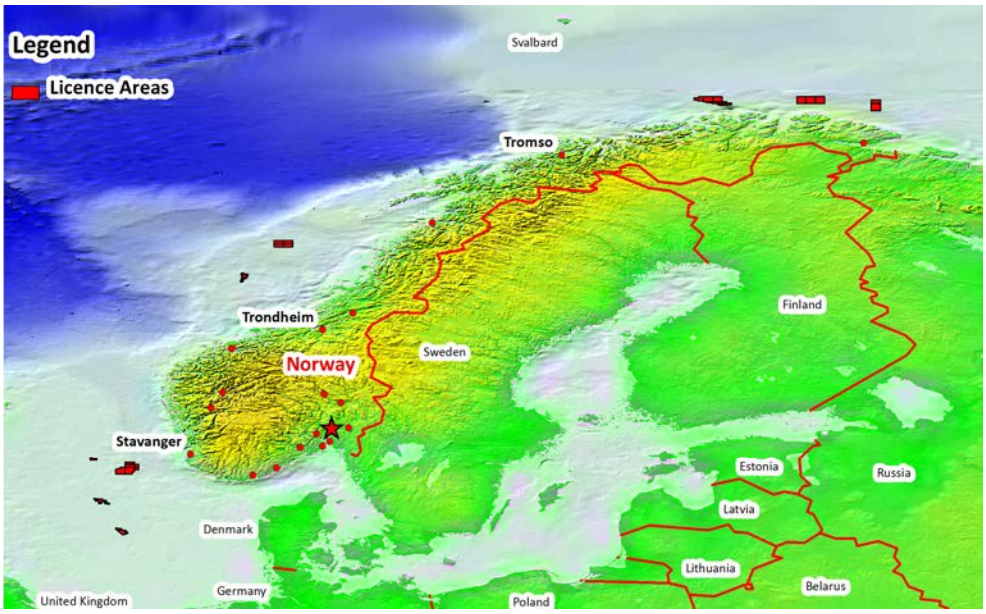
Schema showing general operating areas



Source: ESRI & SPA data

Figure 13 – Licences Norway

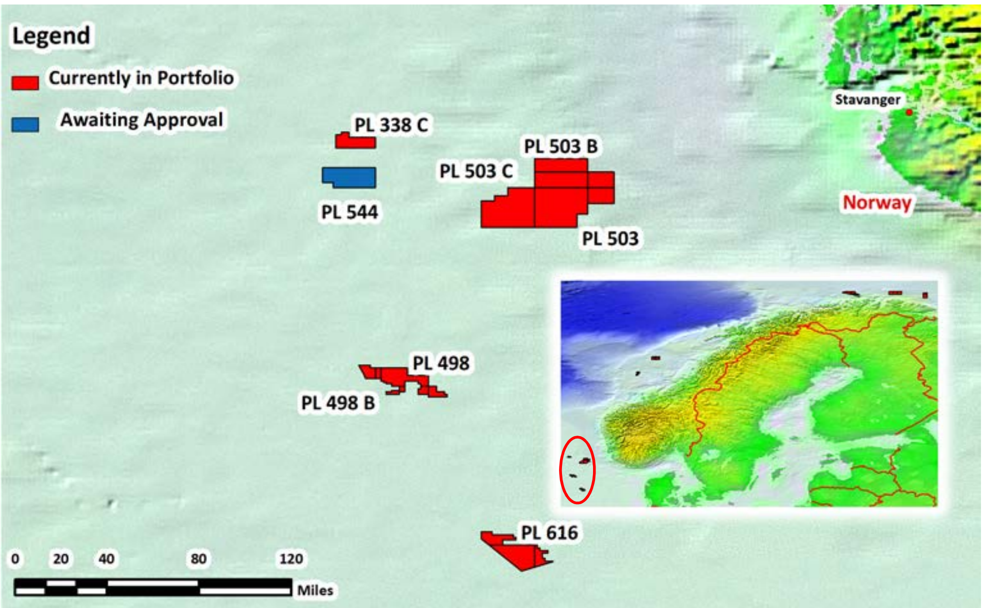
Overview of Hibiscus' Norwegian Licences



Source: NPD, ESRI & SPA data

Figure 14 – PL338C, 498s, 503s, 544 and 616 Licences – North Sea Area

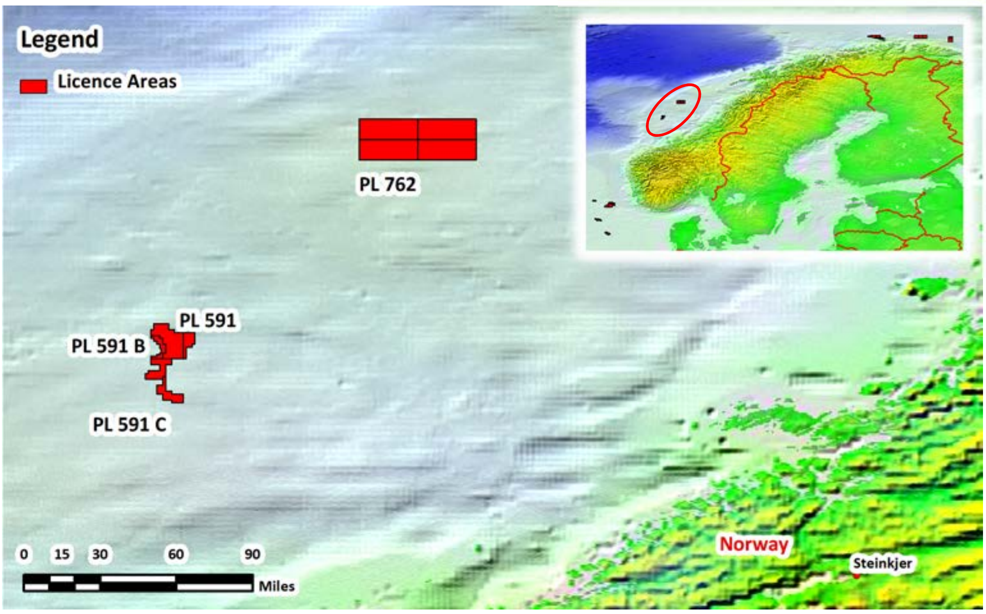
Hibiscus Licence Areas – 544 (Blue) approval pending



Source: NPD, ESRI & SPA data

Figure 15 – 762 & 591 Licences – Norwegian Sea Area

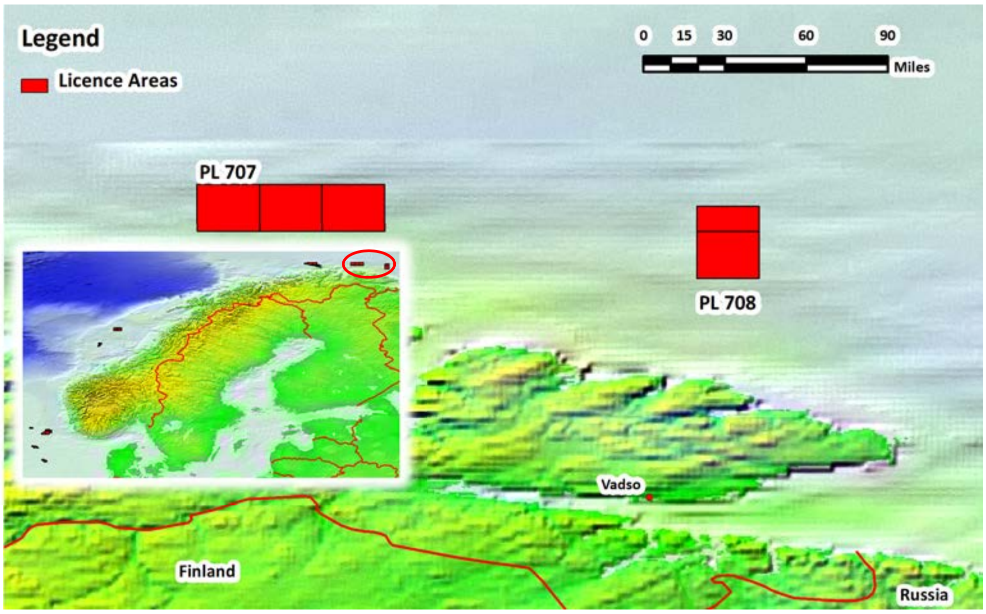
Hibiscus Licence Areas



Source: NPD, ESRI & SPA data

Figure 16 – 707 & 708 Licences – Barents Sea Area

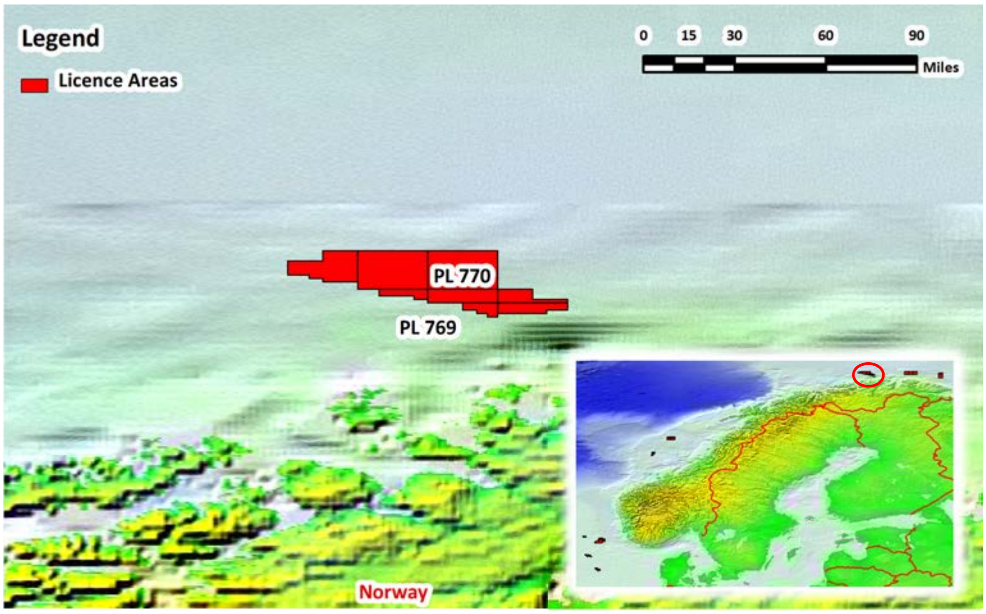
Hibiscus Licence Areas



Source: NPD, ESRI & SPA data

Figure 17 – 769 & 770 Licences – Barents Sea Area

Hibiscus Licence Areas



Source: NPD, ESRI & SPA data

Oman

Hibiscus operates a single licence in Oman, namely, Block 50. However, within that block the Company has identified a significant number of attractive prospects, the most recent of which, GA South, has been drilled and made a discovery, with a preliminary well test flowing 3m bpd of light oil to the surface; the licence is summarised in Table 19 and shown in Figure 18.

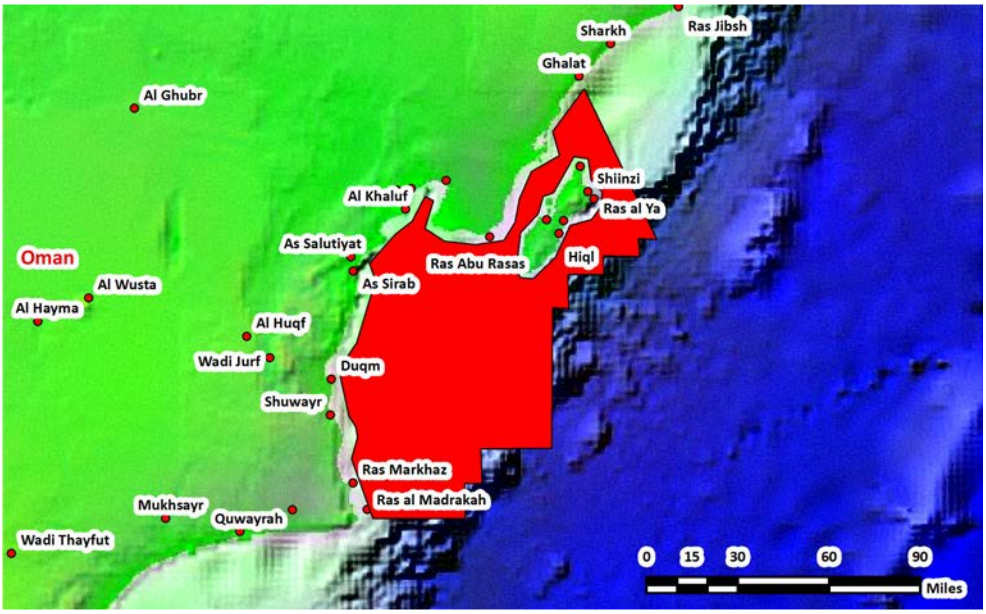
Table 19 – Licence Working Interest Summary – Oman

Licence	Net Working Interest[‡]	Area Summary
Block 50	64%	Located ~6miles offshore Oman in the Masirah Sea (Figure 18). Water depths average 100m in this area.

Source: Company & SPA data
‡ - interest as provided by the NPD. The interest net to Hibiscus is 35% of the above.

Figure 18 – Licences – Oman

Summary of Hibiscus' Omani Licences



Source: ESRI & SPA data

United Arab Emirates

Hibiscus has 3 licence interests in the UAE (Table 20), a single onshore licence in Ras Al Khaimah and 2 offshore licences, 1 in the Arabian Gulf and 1 in the Gulf of Oman (in two parts) to the north of its existing acreage in Oman.

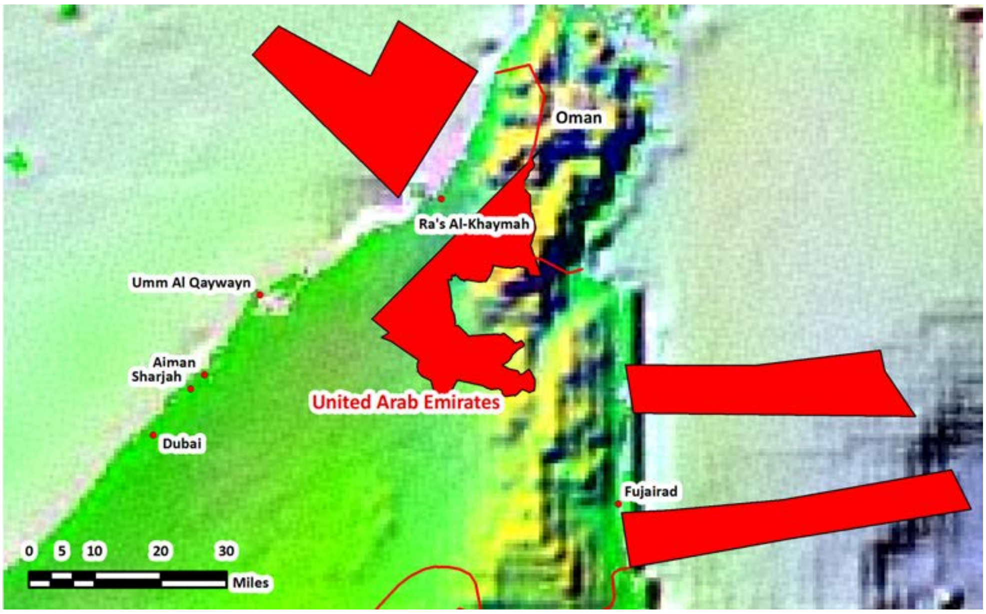
Table 20 – Licence Working Interest Summary – United Arab Emirates

Licence	Net Working Interest‡	Area Summary
Ras Al Khaimah North – Areas B & C	59%	Licence covers the area surrounding the Saleh field, which is 70% owned by DNO (Figure 19). The presence of the Saleh field within the block significantly reduces associated exploration risks. Block to the South East of area B (Figure 19). Some exploratory drilling has been conducted historically, but no discoveries have been reported, although significant shows have been recorded in well logs.
Ras Al Khaimah Onshore	100%	New block (Figure 19) at the early stage of exploration.
Sharjah CA	100%	New block (Figure 19) at the early stage of exploration.

Source: Company & SPA data
‡ - interest as provided by the NPD. The interest net to Hibiscus is 35% of the above.

Figure 19 – UAE Licences

Summary of Hibiscus' UAE Licences



Source: Company, ESRI & SPA data

Geology of Hibiscus' Operating Areas

Hibiscus has interests in licences in some of the world's most prolific hydrocarbon basins, covering a wide range of play types and at differing stages of the exploration cycle.

Hibiscus has interests in 22 licences (and part licences) across 4 countries (summarised in Table 21), namely: (i) Australia; (ii) Norway; (iii) Oman; and (iv) the United Arab Emirates. SPA groups basins regionally, with Hibiscus operating in the: (i) Australasian Region; (ii) European Region; and (iii) Middle Eastern Region (Figure 20).

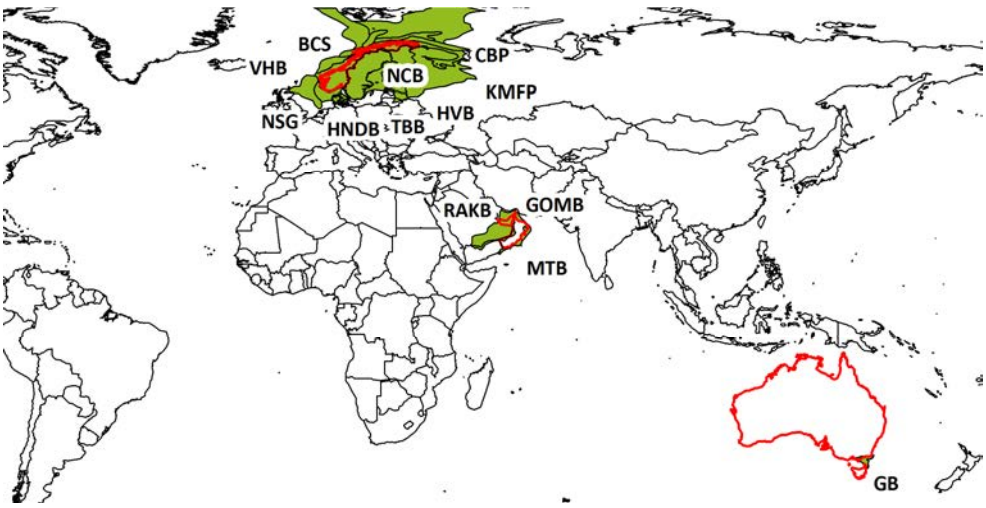
Table 21 – Basin Summary

Region	Country	Province/Basin	Summary	Page
Australasia	Australia	Gippsland	Two licences held in the Gippsland Basin, one contains the West Seahorse discovery, while the other contains the soon to be drilled Sea Lion prospect.	27
Europe	Norway	North Sea Province	Most assets located in the North Sea Central Graben Basin, which is one of the most prolific basins globally.	40
		Norwegian Sea Province	Relatively new area and currently underexplored. New drilling and production technology is making development economic.	44
		Barents Sea Province	Considered to be a frontier basin which has been subjected to very little exploration drilling.	45
Middle East	Oman	Masirah Trough	Largely underexplored due to the prolific onshore basins in Oman. New understanding and support from the government is renewing interest in the offshore Oman basins.	49
	UAE	Gulf of Oman	Relatively underexplored and until recently was considered to be either an extension of the Masirah Trough. However, new interest in the basin has been sparked by changes to the fiscal regime and a more detailed understanding of its prospectivity.	58
		Rub al Khali	While a prolific hydrocarbon basin producing significant quantities of oil in the Saudi Arabian section of the basin, the basin has been relatively underexplored in certain areas, most notably in Ras Al Khaimah.	66

Source: Company, USGS & SPA Data

Figure 20 – Operating Basins

Geological basins which Hibiscus operates in



Source: USGS, ESRI & SPA data
NOTE: Countries of interest are outlined in red.

Table 22 – Figure 20 Legend

Abbreviated Name	Basin
BCS	Barents Continental Slope Basin
CBP	Central Barents Platform Basin
GB	Gippsland Basin
GOMB	Gulf of Oman Basin
HNDB	Horda-Norwegian-Danish Basin
HVB	Hammerfest-Varanger Basin
KMFP	Kola Monocline-Finnmark Platform
MTB	Masirah Trough Basin
NCB	Norwegian Caledonides Basin
NSG	North Sea Graben Basin
RAKB	Rub Al Khali Basin
TBB	Troms-Bjornoya Basin
VHB	Vestford-Helgeland Basin

Source: USGS & SP Angel data

In compiling this section, we have drawn heavily on the information provided by the United States Geological Service and Geoscience Australia.

Oceania Basins

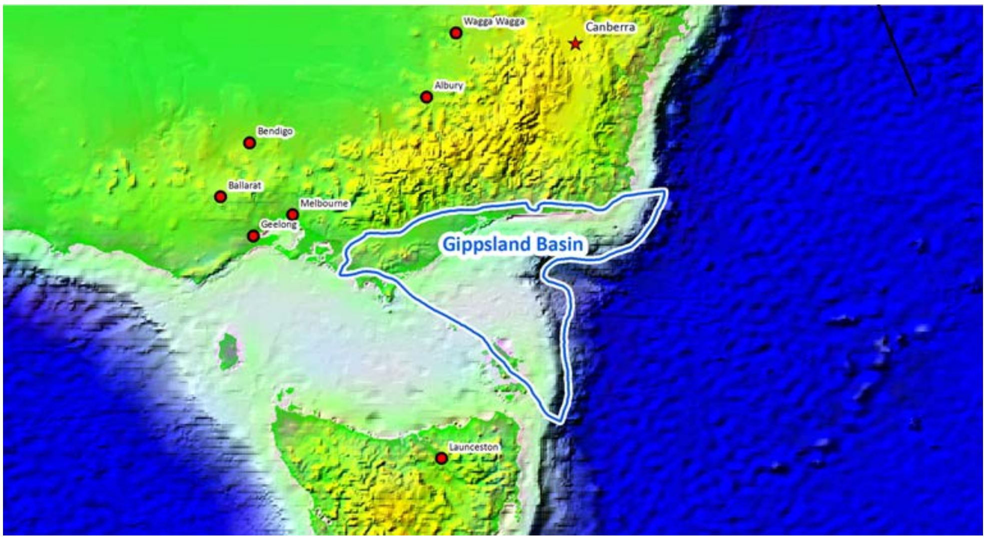
Hibiscus' two Australian licence interests are located solely within the Gippsland Basin, which is in the south east of the country, primarily offshore Victoria. We will discuss this basin in high-level in the following.

Gippsland Basin

The Gippsland Basin ("GB"), is located on the southeastern coast of Australia (Figure 21), is formed from two successive failed rifts that developed into a passive margin during the Cretaceous, covers an onshore and offshore area of Victoria that is approximately 4,600km^2.

Figure 21 – Gippsland Basin

Schematic of the location of the Gippsland Basin



Source: USGS, ESRI & SPA data

The Gippsland Basin has been a significant source of oil and gas in Australia since offshore production began there in 1969. Reserve estimates published in 1976 estimated recoverable reserves of 1,972mm bbl, 174 mm bbl, 469mm bbl of liquid petroleum gas and 7.8tcf of gas; to date, however, the Gippsland Basin has produced in excess of 3,650mm bbl and 5tcf.

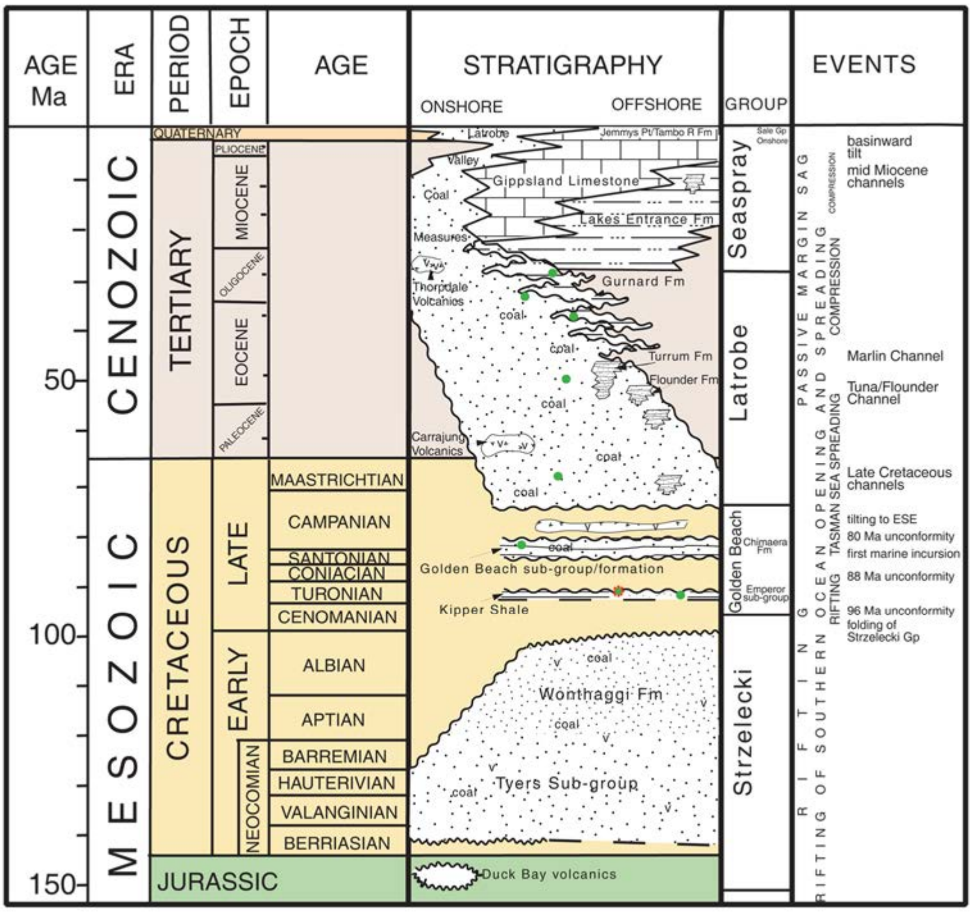
Geological Setting

Formation of the Gippsland Basin is related to the breakup of Gondwana, which resulted in the separation of Antarctica from Australia, and the separation of the New Zealand and Lord Howe Rise continental crust from Australia. Coals and coaly shales of Late Cretaceous through Eocene age are the source rocks for oil and gas that accumulated predominantly in anticlinal traps. The basin was Australia's major producing basin until 1996 when daily oil/condensate production from the North West Shelf surpassed it.

There are a number of facies that have been either productive or have shown significant promise in the Gippsland Basin, most notably the Gippsland series, which gives its name to the basin. It consists of Upper Cretaceous upper coastal plain coals and coaly shales of the Latrobe Group as the source rock and Upper Cretaceous through Eocene Latrobe Group fluvial, deltaic, and marginal marine sandstones as reservoir rocks (Figure 22).

Figure 22 – Gippsland Basin – Stratigraphy

Gippsland Basin Stratigraphy



Source: USGS & SPA data

Based on geochemical studies to date, it is strongly suggested that the discovered reserves in the Gippsland Basin are derived from these terrestrial coals and coaly shales. Nearly 75% of the estimated discovered recoverable oil and gas reserves are found in anticlines, domes, and rollover traps, and the overwhelming majority (85%) is found in the reservoir sandstones of the Latrobe Group.

The underlying and adjacent Strzelecki (Lower Cretaceous) and Golden Beach (Lower and Upper Cretaceous), which is also known as the lower Latrobe Groups (Figure 22) may have contributed hydrocarbons to overlying accumulations and adjacent accumulations where vertical and lateral out-of-basin migration paths are considered.

The offshore producing area of the Gippsland Basin is located in the waters of Victoria, with the southern portion located in the waters offshore Northern Tasmania. The basin averages 300km in width and contains sediments more than 8km thick.

Tectonics

During Late Jurassic to Early Cretaceous time, the Gippsland Basin was part of a rift complex in excess of 600km, that formed between the Australian Plate/Tasman Fold Belt and the Antarctic Plate. This Bassian Rift System included three major components from west to east, the Otway, Bass and Gippsland Basins.

By mid-Late Cretaceous time, this rift complex was the site of the separation of Gondwana along what is now the southern margin of Australia, although the Late Jurassic rift complex was located between Australia and Tasmania, Late Cretaceous separation and creation of ocean crust occurred to the west of Tasmania.

Separation and creation of ocean crust in the latest Cretaceous Tasman Rift event progressed along the eastern side of Tasmania and Australia, sequentially separating the Australian Plate from the continental crust of New Zealand/Lord Howe Rise (initially), and then the Antarctic Plate from continental crust of the Campbell Plateau, which left leaving Tasmania attached to Australia.

Regional extension and development of syn-rift troughs and volcanism, beginning at approximately 96mya, occurred in the Gippsland Basin, which marked its differentiation from the other two components of the earlier Bassian Rift System.

Structure

The Gippsland Basin trends east-west and is comprised of a deep central depression symmetrically bounded by faulted terraces and stable platforms which are located to the on the north and south (Figure 23).

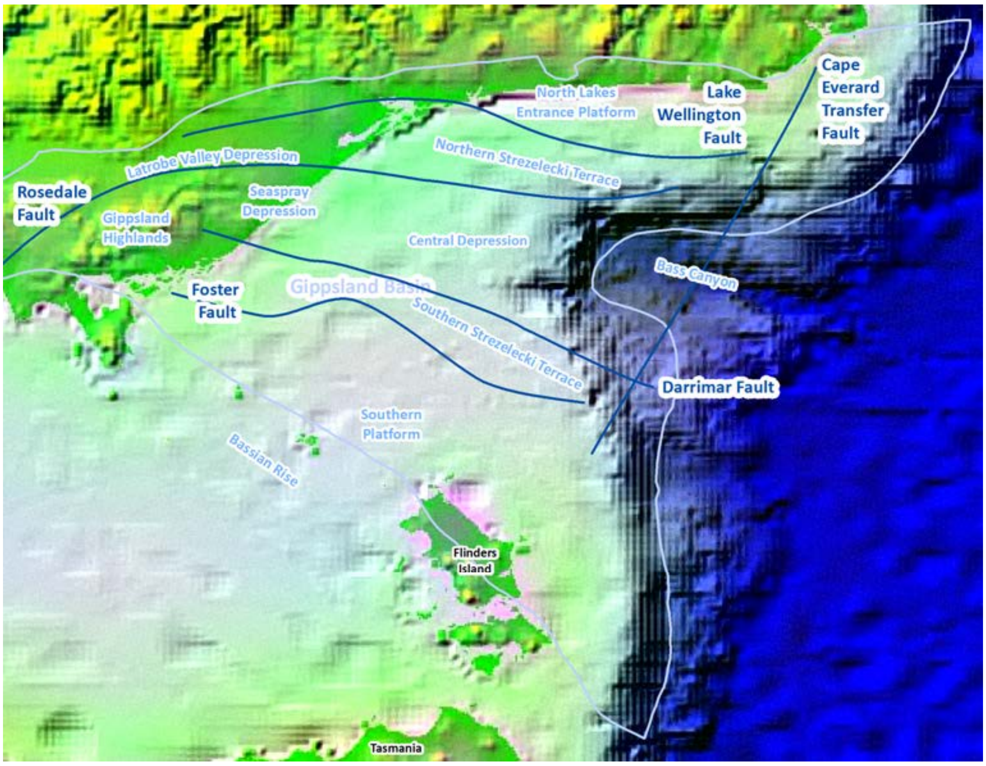
The Lakes Entrance Platform, is bounded on the south by the Lake Wellington fault and the Southern Platform is bounded on the north by the Foster fault system (Figure 23). Basin sediments out crop in the west and are deeply buried offshore, dipping to the east.

The deep Central Depression (Central Deep) continues onshore as the Seaspray Depression (Figure 23). It lies between the Rosedale fault, which defines the southern edge of the Northern Strzelecki Terrace, and the Darriman fault, which defines the northern edge of the Southern Strzelecki Terrace (Figure 23).

Normal faults trending northwest to southeast, of Early Cretaceous to Early Eocene age, characterize the central depression. The major fields are located in anticlinal traps formed by compressional events and shear faults associated with the opening of the Tasman Sea. Late Eocene to Early Oligocene and Late Miocene age anticlines are generally oriented southwest to northeast and are located in the central depression and on the northern terrace.

Figure 23 – Gippsland Basin – Structure

Generalised Structural Features of the Gippsland Basin



Source: USGS, ESRI & SPA data

A variety of Paleozoic rocks underlies the Gippsland Basin. Much of the area was covered by glaciers that came from Antarctica, located to the southwest, in Early Permian time. The Strzelecki Group is observed at various locations as unconformably overlying Permian sediments, Upper Devonian rocks, Lower Devonian rocks, Devonian granite, and in other locations as faulted against Lower Devonian or Silurian beds.

At one onshore well location on the Northern Strzelecki Terrace near the Lake Wellington fault, a post-glacial, marginal marine to deltaic Lower Permian sandstone, shale, and siltstone section more than 180m thick was described overlying folded Ordovician rocks.

Both crystalline basement and metamorphic basement have been described in onshore wells on the Lakes Entrance Platform. Extrusive igneous rocks were reported in the most southerly well in the province, which is located on the Southern Platform offshore Flinders Island.

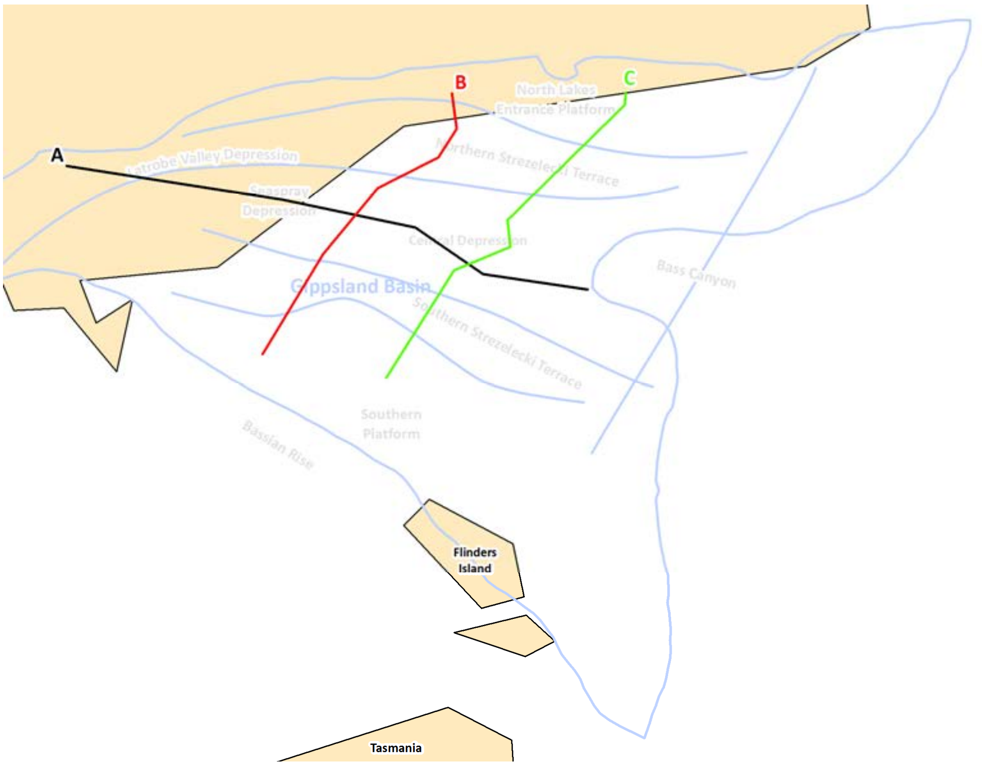
Jurassic age rocks were reported in wells located onshore on the Southern Strzelecki Terrace in the westernmost area of the province, and on the Northern Strzelecki Terrace near Lake Wellington.

Deposition

Depositional environments in the Gippsland Basin can be broadly characterised by that experienced in X groups, namely: (i) the Strzelecki Group: (ii) Golden Beach Group; and (iii) Seaspray Group, which has been interpreted from a number of synthetic seismic lines (Figure 24), and summarised in the following text.

Figure 24 – Gippsland Basin – Cross Section Locations

Generalised Location of Seismic Lines A, B & C



Source: USGS, ESRI & SPA data

Strzelecki Group

The Gippsland Basin includes Lower Cretaceous continental and lacustrine clastics deposited in an extensional rift trend that extended along the modern southern margin of Australia and which had formed between the then connected Australia Plate and the Antarctic Plate of Gondwana; these deposits are known as the Strzelecki Group.

The known extent of the nonmarine Strzelecki Group, is approximately between the Foster fault system to the south and the Lake Wellington fault to the north and from the Gippsland Highlands east, to where the strata are interpreted from seismic data (Figure 25).

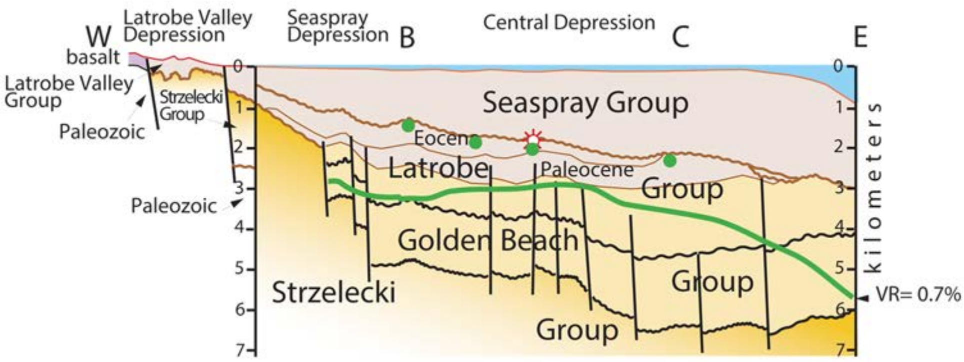
The group crops out onshore in uplifted fault blocks of the Gippsland Highlands (Strzelecki Ranges) and northeast of Yallourn, with exposures covering more than 3,900km^2. The Strzelecki Group is of Early Cretaceous age and was deposited in an eastwest trending rift basin complex that began as a pre-breakup depression and failed rift approximately 130mya.

The rift complex was the eastern extension of the Otway and Bass Basins, which also received sediments of similar composition and depositional environment beginning in the Late Jurassic. The correlative group in the Otway Basin is a good coaly source rock that sources gas in at least two fields.

Exploration in the Gippsland Basin has thus far considered the nonmarine Strzelecki Group to be economic basement and unprospective, but new research is currently reconsidering its potential.

Figure 25 – Gippsland Basin – Cross Section Line A

Schema of the Generalised Stratigraphy along "Line A"

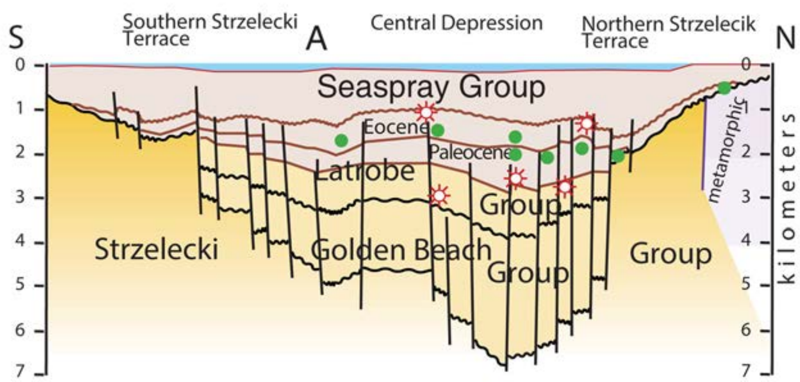


Source: USGS & SPA data

The group occurs in the subsurface to the north and south of the productive Upper Cretaceous trend, on the Northern Strzelecki Terrace and the Southern Strzelecki Terrace but has not been explored under most of the productive trend in the offshore Central Depression because of drilling depths that generally exceed 5 – 7km (Figure 26).

Figure 26 – Gippsland Basin – Cross Section Line B

Schema of the Generalised Stratigraphy along "Line B"



Source: USGS & SPA data

Thickness of the Strzelecki Group generally ranges from a few hundred meters to more than 2,600m but estimated thickness in some areas is as much as 6,000m. The group is composed of nonmarine greywackes, mudstones, sandstones, conglomerates, coals, and volcanoclastics; depositional environments include lakes, swamps and floodplains.

Subdivision and correlation of units within the group have proven difficult, although outcrops were described as early as 1856 in connection with evaluations of coal resources. The lower portion of the Strzelecki Group consists of the Lower Neocomian Tyers Conglomerate and finer grained equivalents deposited on a Paleozoic age erosional surface on granites and metamorphics.

The upper Strzelecki Group consists of coals, shales, siltstones, and volcanic sandstones of the Wonthaggi Formation. Medium- to fine-grained feldspathic sandstones make up more than 40% of the outcrop area.

Lenticular and cross-bedded sandstones 60 m thick are common, and sandstone sequences are as much as 140m thick in some outcrops. The sandstone contains oligoclase, orthoclase, perthite, microcline, quartz, biotite, hornblende, andesite and calcite. Mudstone beds are as much as 130m thick and are mineralogically similar to the sandstone except that the mudstone is dominantly potassic whereas the sandstone is dominantly sodic.

Potential sandstone reservoirs within examined intervals of the Strzelecki Group are of poor quality, having poor porosity due to diagenetic clays and alteration of volcanic rock fragments. Better reservoirs and good exploration targets may be defined with an exploration program aimed specifically at rift-basin style stratigraphy and traps.

The source-rock potential of the coals and lacustrine shales in the group is poorly known, although the subsurface edges of the depositional extent of the group appear to be in the oil window along the northern and southern terraces, and methane occurrences at the margins of the basin may have been sourced by the Strzelecki Group.

The Lower Cretaceous Strzelecki Group was deformed and eroded by a 96mya event that may have included compressional realignments of the breakup of Gondwana (Figure 22). Strata of latest Early Cretaceous through Cenomanian age are not present.

The overlying Late Cretaceous Central Depression, developed between the northern and southern terraces, has buried the Strzelecki Group offshore to depths of more than 8km and currently into the overmature range.

Golden Beach Group

The Golden Beach Formation of the Latrobe Group was first described following the drilling results of the Golden Beach 1A well drilled in 1967. This formation was described as continental sandstone and shale overlying the Strzelecki Group and underlying the unconformity within the N. senectus palynomorph zone.

Since 1990 the lower Latrobe has been described in the literature as the Golden Beach Group (Figure 22). The Golden Beach Group was deposited in a rapidly subsiding, extensional rift trend of a slightly different orientation that overprinted and formed within the trend that existed during deposition of the Strzelecki Group.

The rift was occupied by deep-water lakes and, following the breakup of the southern Australian margin, was flooded by marine waters. Where the Golden Beach Group is present, it rests unconformably on the Strzelecki Group (Figure 22). Mineralogy changes from volcanogenic in the Strzelecki Group to quartzose in the Golden Beach Group.

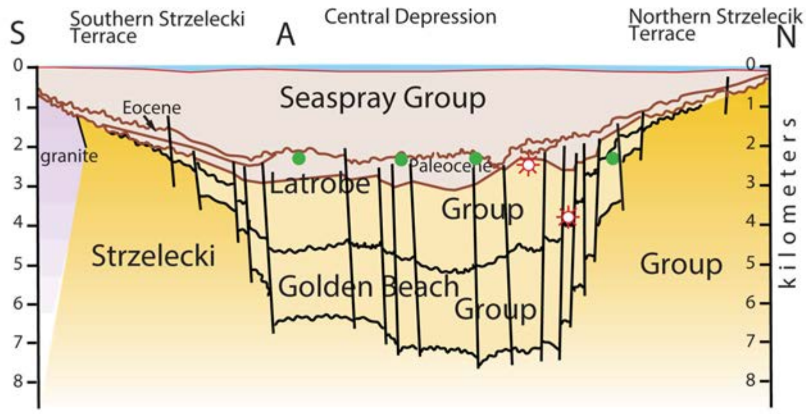
The Golden Beach Group is divided into the Turonian age Emperor sub-group and the Santonian to Campanian age Golden Beach sub-group, which is also referred to as the Golden Beach Formation or Chimera Sandstone.

It has been noted that an unconformity of Turonian to Santonian age of an estimated 5myseparates the two sub-groups (Figure 22). The Kipper Shale of the Emperor sub-group was deposited in lakes. This lake complex is described as deep and persistent through time with lake surface areas estimated at 5,000km^2, evidenced by thick sections of lacustrine shale observed in drillings.

In the Manta and Basker fields area, the lower Latrobe Group is described as alluvial sandstones with interspersed volcanic flows of andesitic to basaltic composition; a cross section of this is provided in Figure 27.

Figure 27 – Gippsland Basin – Cross Section Line C

Schema of the Generalised Stratigraphy along "Line C"



Source: USGS & SPA data

More than 600 m of Golden Beach Group is preserved in the Central Depression offshore area, as well as in parts of the adjacent onshore Seaspray Depression (Figure 23). Normal faulting along the Rosedale and Darriman faults truncated and then confined deposition of the group to the rapidly subsiding depression between the Northern and Southern Strzelecki Terraces.

Development of these terraces coincides with opening of the Tasman Sea beginning at 80mya. The first marine influences in the Gippsland Basin occurred in middle Santonian time during deposition of the Golden Beach sub-group and the transgressions are interpreted by some to have come from the southwest.

The Campanian rocks are described as sandstones and overbank shales that were deposited across a coastal plain by a meandering river system with north to south flow. An unconformity developed on top of the sediments of the Golden Beach subgroup approximately 80mya, with subsequent latest Campanian volcanics resting unconformably on this surface.

The Golden Beach and Strzelecki were tilted to the east-southeast and eroded. This Campanian tectonism and associated volcanism accounts for major displacements on intra-Golden Beach sub-group faults, and for the extrusion of the surface basalt flow that serves as a seal for gas and oil traps in Golden Beach sandstones at Kipper Field.

Latrobe Group

Late Cretaceous (Campanian) tectonism, which ended deposition of the Golden Beach Group, resulted in (i) the separation of Gippsland Basin from the Bass Basin by the Bassian Rise, and (ii) the emergence of the Southern Platform (Figure 23). Paleogeographic maps portray the basin during latest Cretaceous Latrobe deposition as a gulf facing the opening Tasman Sea to the east with two structurally controlled lows traversing the Gippsland Rise (Figure 23).

The Gippsland Rise is shown as sometimes emergent with circulation from the sea through the structural lows. By the end of the Cretaceous, the offshore Gippsland Basin began to subside as a marginal sag. Compression became the dominant tectonic style from Eocene to Miocene time during the passive margin stage related to the continuing opening of the Tasman.

The Latrobe Group consists of sandstones, siltstones, mudstones, shales, coals, and volcanics that were deposited in alluvial, shoreline and shallow to shelf marine settings and deep-water low-stand cut-and-fill channels; the thickness of the sequence totals more than 4,500m within the Central and Seaspray depressions.

The Cretaceous to Paleocene portion of the Latrobe Group is interpreted to have been sand-rich coastal plain and barrier sediments deposited in an aggradational setting. Multiple transgressions and regressions of coastal plain and barrier settings are recorded in the Late Paleocene to Eocene portion of the group. Paleoshorelines trended generally southwest to northeast and were located, for the most part, between Mackerel and Blackback fields.

These paleogeographic reconstructions show a wide zone of migrating shoreline environments backed by an extensive coastal plain surrounded by alluvial and fluvial settings within the confines of the faulted basin during deposition of the lower Latrobe section. Clastic sediments were sourced from the Australian continent to the north and the Bassian Rise and Southern Platform to the southwest and south of the basin as well as from the west along the basin axis (Figure 23).

Westward marine transgressions and eastward regressions of the Tasman Sea alternated with periods of continental clastic sedimentation, but no major deltaic sequences have been described. These sediments progressively onlapped the terraces to the north and south and onlapped to the west during Late Cretaceous through Oligocene time. Onshore in the northwest area, the Strzelecki Group is overlain by a series of Latrobe Group formations: an Eocene or Paleocene sandstone, Thorpdale Volcanics consisting of Eocene basaltic lavas, Oligocene to Miocene age nonmarine clastics, and Latrobe Valley Coal Measures.

In the onshore Seaspray Depression, Latrobe Group rocks are described as Upper Cretaceous to Oligocene non-marine sandstones, siltstones, mudstones, coals and shales. The Maastrichtian-Paleocene upper Latrobe Group rocks in the offshore area are described as having been deposited in coastal plain, shoreline, and nearshore settings featuring a series of thick barrier bar facies.

Eocene paleogeographic reconstructions show as much as a 40 km wide coastal barrier fronted by wide shallow marine environments and backed by a coastal plain that was no longer confined by the faulted basin.

Tectonic uplift of the northeastern basin in Eocene time along with sea level lowstands, caused deep submarine channelling into strata of the Latrobe Group and into anticlines involving these rocks. Three of these erosional unconformities occur at the Blackback field anticline. Major channelling events include a Maastrichtian event, the early Eocene Tuna/Flounder channel that was filled by the Flounder Formation and the Eocene Marlin Channel filled by the Turrum Formation (Figure 22)

The current Bass Channel, or Bass Canyon, occupies the southern structural passage across the Gippsland Rise and erodes into the Latrobe Group. The Gurnard Formation, where present, is generally placed at the top of the Latrobe Group and consists of offshore (Eocene) to onshore (Oligocene) glauconitic sandy siltstone. Further onshore in the Latrobe Valley, deposition of the Latrobe Valley Coal Measures continued through the Pleistocene.

Another tectonic event formed an extensive erosion surface on top of the Latrobe Group 50mya. The overlying Seaspray Group consists of shales and marls that are the regional seal for the majority of fields in the Gippsland Basin (Figure 22). Unconformities and at least two mid-Miocene channel cut-and-fill events are present within the Seaspray Group.

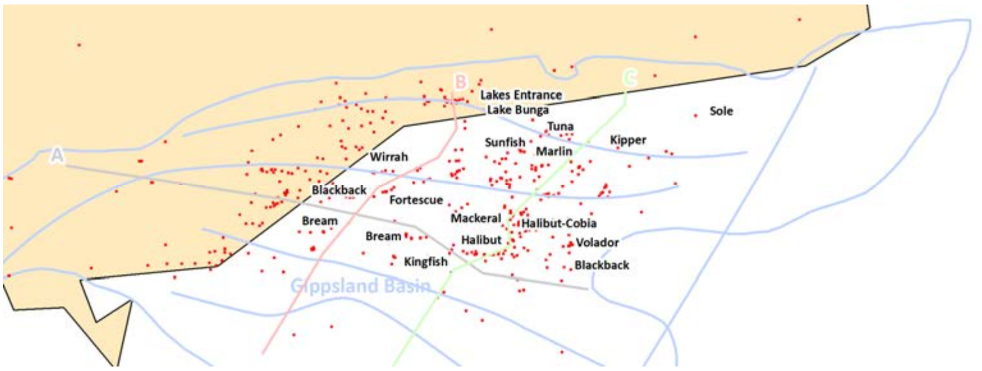
Compression during Seaspray time is represented by gentle unfaulted anticlines in contrast to older faulted anticlines.

History OF Petroleum Exploration

Oil and Gas was first discovered onshore at the Lake Bunga No. 1 well in 1924, near Lakes Entrance, which started exploration interest in the Gippsland Basin. Cumulative production from the Lake Bunga field (Figure 28) to 1956 of 10,000 barrels of biodegraded, heavy crude oil from an Oligocene sandstone in the onshore Lakes Entrance Field was overshadowed by later activity in the offshore areas.

Figure 28 – Gippsland Basin – Main fields

Generalised Location of the Main Fields in the Gippsland Basin



Source: USGS, GeoscienceAustralia, ESRI & SPA data

In December of 1964 the drill ship Glomar III began exploration in offshore Gippsland Basin drilling Esso Gippsland Shelf No. 1, in what is now known as Barracouta Field (Figure 28). Gas production from Barracouta began in early 1969 from Late Eocene Latrobe Group clastic reservoirs in a faulted anticline. Oil was also discovered and later produced from the same field.

Petroleum Occurrence

Gippsland Basin gas fields are located generally in the west-central and northcentral areas (the large Barracouta, Bream, Snapper, and Marlin Fields – Figure 28), and oil fields are located in the east-central and west areas (the large Cobia-Halibut, Fortescue, Kingfish, Mackerel and Blackback Fields – Figure 28).

This distribution is considered to be a result of local subsidence combined with general heatflow producing areas where the source rock is overmature and generating gas, and other areas where it is mature and generating oil. This distribution is further influenced by local versus areal hydrocarbon drainage areas and migration paths.

There are three major stratigraphic targets that have proved successful in exploration for hydrocarbons, (i) Top Latrobe, (ii) intra-Latrobe, and (iii) pre-Latrobe. The largest fields and approximately 85% of the total discovered reserves are found in Latrobe Group reservoirs.

Fields also occur in strata younger that the Top Latrobe such as Lakes Entrance Field (Figure 28). The earliest offshore discoveries were in anticlines under the unconformity that defines Top Latrobe. These remain the largest fields discovered in the basin. The Top Latrobe unconformity was developed by a tectonic event 50mya.

This unconformity eroded the Latrobe Group strata and anticlines involving the Latrobe Group. Reservoirs beneath the Top Latrobe unconformity vary from Late Cretaceous to

Eocene in age. The fields immediately below the Top Latrobe are fed by hydrocarbons migrating from large areas of the basin and adjacent synclines. Intra-Latrobe fields contain hydrocarbons in Latrobe reservoirs that are not associated with the Top Latrobe unconformity.

These reservoirs are fed by local migration of hydrocarbons within fault blocks and reflect maturation of source rock in a smaller area. Pre-Latrobe fields are located on the edges of the basin with reservoirs in the Golden Beach Group. Although Gippsland Basin oils have been attributed to the same source rock, there is considerable variation in chemical composition ranging from very waxy and paraffinic to light and condensate-like.

These differences are attributed to oil being generated at different maturities, low reservoir temperatures, and the presence of a fresh-water wedge that extends from the present shoreline east and south into the basin and to depths of as much as 2,400m. Oils in traps at Top Latrobe are not chemically distinct from oils in traps within the Latrobe Group. Gas generation from a deep overmature source has been suggested.

Analysis of six fields showed the carbon isotope composition of methane to range from –31.4 to –41.4 per mil, and oil gravity ranging from 15.4°-64° API; almost universally sulphur content is below 0.5% $^{wt}/_{wt}$.

A trend of oil gravity increasing with source rock maturity has been demonstrated, most evident in the Wirrah Field (Figure 28). The field's reserves have been located a number of different locations, with oil found at 2,633m and 2,046m are heavier in nature, being identified as originating from were identified as being from early mature source rocks, while reserves at 2,195m were lighter in composition and deemed to have originated from peak mature source rocks.

Source Rock

The results of analyses of oils and potential source rocks indicate that terrestrial source rocks – coals and lower coastal plain coaly shales--show excellent correlation with the produced oils of the Gippsland Basin. These strata in the Latrobe Group contain total organic carbon contents ("TOC") as much as 70%$^{wt}/_{wt}$ and hydrocarbon indicies ("HI") as high as 400mg hydrocarbon ("HC")/g TOC; these are widely considered to be the Gippsland Basin's source rocks.

Marine shales of this group are reported to have TOC values of 1 – 3%$^{wt}/_{wt}$. The average TOC of the Golden Beach Group is 2 – 3%$^{wt}/_{wt}$. The dominantly aggradational setting described by Fielding (1992) during the Cretaceous to Paleocene period of Latrobe deposition may have favoured deposition of coal and coaly shale source rocks. Furthermore, is has been demonstrated that low-ash coals that are best developed landward of aggradational shorelines and discussed the development of raised peat mires that may have influenced aggradation; one oil sample showed an algal influence in a dominantly terrestrial character.

The estimated 1,000-m-thick Kipper Shale did not correlate with any of the oils analysed, exhibiting average TOCs 2 – 4%$^{wt}/_{wt}$ and is characterized as gas-prone with S_2 values below 2mg/g and HI below 100mg HC/g TOC. Well intersections at Kipper, Tuna, Emperor, Sunfish and Sole (Figure 28) encountered more than 700m of lacustrine shale described as lean source rocks with HI of 80 – 200mg HC/g TOC. The poor source-rock quality of this lacustrine shale has been attributed to oxidation of organic matter due to seasonal turnover of the lake waters of this cold climate setting at this latitudes (65° South).

This lacustrine shale could be a source for some gas in the Gippsland Basin. Possible source rocks in the coaly section of the Strzelecki Group penetrated in onshore wells range from 0.21 to 26.83%$^{wt}/_{wt}$ TOC, with vitrinite reflectance values ("R_o") 0.35-1.04% and HI values from 23 – 179mg HC/g TOC.

Maturation And Migration

Peak generation and primary migration occurs at depths of 4 – 5km for oil and 5 – 6km for gas. Maturation studies and sampling from the deep Volador-1 well (Figure 28), to 4,611m, indicate that maturation and peak hydrocarbon generation of the source rocks occurs at R_o of between 0.92 – 1.00%. This is in contrast to maturation of shale source rocks like the Kimmeridge Clay Formation in the North Sea, which reach peak generation at around R_o 0.80%.

Calculated maturity from source-rock extracts was compared to vitrinite reflectance measurements indicates that discovered oils were generated at maturity levels of R_o 1.15 – 1.30 %, and gas from the overmature section at maturity levels of Ro 1.25 – 2.00 %. Oil and gas generation and expulsion from Golden Beach and lower Latrobe source intervals in the central eastern portion of the Gippsland Basin occurred in Late Cretaceous and Early Paleocene time due to higher heatflow and subsidence of this area prior to formation of trapping structures in Late Eocene to Middle Miocene time (Figure 25)

Subsequent to Miocene trap formation, oil has been generated from younger Latrobe source intervals, accounting for the predominance of oil fields in this region. Gas has been the dominant hydrocarbon generated since trap formation in the area north of Barracouta field (Figure 28), which explains the predominance of gas fields in the north and western portions of the basin.

Vertical migration of 2km or more occurs in the central portions of the Gippsland Basin, and significant lateral migration is cited for accumulation on the Northern Platform (Figure 26 and Figure 27). Discovery trends that locate most oil in the middle of the basin and most gas toward the margins are explained by the migration paths and the state of maturity of the immediately adjacent synclinal "kitchen" and the timing of compressional trap formation.

Oil fields found on the margins of the basin are thought to tap only oil-mature source rocks within the migration area. Hydrocarbons from the deepest parts of the basin were expelled during an early phase of generation in the Paleocene, but the main phase of generation has been in the last 20my. Structures in the northwest were not available for early oil migration so these structures have trapped mostly mature gas. Source rocks in the southwestern portions of the basin are still in the oil window.

There may have been some contribution of hydrocarbons from Strzelecki Group source rocks to the Latrobe petroleum system. Hydrocarbon generation and expulsion modelling from onshore wells in the Seaspray Depression and on the Northern Strzelecki Terrace near Lake Wellington indicate that there was one widespread expulsion event in this area at 115 – 95mya and a second event detected in some wells between 80mya 40mya with one area possibly continuing to the present.

Trap Types

Compression from Eocene through Early Miocene time resulted in anticlines and fault traps. Most of the large accumulations occur immediately below the Top Latrobe unconformity in anticlines eroded and then sealed by the overlying regional Seaspray Group. The traps were in place in the Kingfish Field area at approximately 28mya (Late Oligocene) and in the

Barracouta Field (Figure 28) area at approximately 22 Ma (Early Miocene). At the Marlin Field, erosional topography creates a larger closure than the anticline alone. Additional traps within the Latrobe Group are fault traps sealed by the fault or juxtaposed shales. However, favourable juxtaposition is difficult in this fluvial, alluvial, and shoreline sandstone dominated group. Intra-Latrobe Group traps in the Barracouta Field (Figure 28) area were in place at approximately 34mya.

Successful fault traps within the Golden Beach Group are formed by lacustrine sandstones juxtaposed against thick lacustrine shale sections. The Kipper discovery (Figure 28) appears to be an inverted structure containing hydrocarbons at several levels: Top Latrobe, intra-Latrobe Group and Golden Beach Group. The Golden Beach accumulation is sealed by a basalt flow and faulted against shale.

Reservoir Rock

The Latrobe Group sandstones are the primary reservoirs of the Gippsland Basin with diagenesis an important factor in reservoir quality. Widespread dolomite cement, grain and cement solution secondary porosity development, illite, kaolinite and chlorite cement, and quartz overgrowths are all factors either occluding porosity or enhancing porosity. Dolomite cement occurs as pore filling and grain replacement and makes up as much as 30% of the total rock volume.

This widespread and variable cementation is the major cause of porosity reduction in the Latrobe Group. Secondary porosity accounts for most of the reservoir porosity, principally as dissolution of dolomite cement that is possibly associated with hydrocarbon emplacement. Dissolution of clay matrix is also a mechanism important in developing secondary porosity in the group, as is dissolution of feldspars and rock fragments.

Porosity may then be occluded by authigenic kaolinite growth, chlorite filling, quartz cementation and overgrowths, and compaction. Porosity versus depth plots for Latrobe Group sandstone reservoirs of the Basker Manta area, suggest a severe decline in porosity approaching 4km burial depth indicating a possible maximum depth of target reservoirs.

Seal Rock

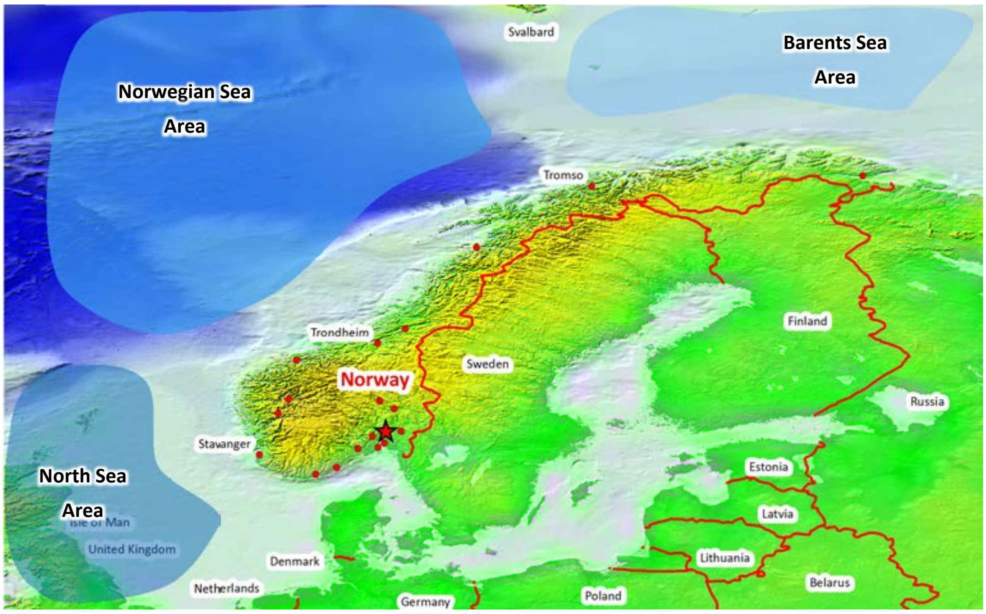
Regionally extensive marine shales and marls of the Seaspray Group provide excellent seals for most of the fields in the area. Shales within the Latrobe Group provide seals for intra-Latrobe Group fields and a basalt flow provides the seal for at least one accumulation.

European Basins

Within the European Basin Region, Hibiscus' sole interests are in Norway. However, the Company has interests in 16 licences in 3 separate hydrocarbon provinces (Figure 29), namely: the (i) North Sea Province (including the North Sea Graben and Horda Basin); (ii) Norwegian Sea Province (including the Vestford-Helgeland Basin); and (iii) Barents Sea Province (including the Hammerfest-Varanger Basin and Kola Monocline).

Figure 29 – European Regional Basin

Location of the North Sea, Norwegian Sea and Barents Sea Provinces within the European Basin Region



Source: USGS, ESRI & SPA data

North Sea Graben Province & Horda Basins

The North Sea Graben Province ("NSGP") (Figure 30) is one of the world's major oil producing regions. North Sea exploration actually began onshore in 1959 with the discovery of the giant Groningen gas field in the Netherlands by Shell and Esso. It was postulated that the thick, high-quality Rotliegend reservoirs of the Groningen series extended further offshore.

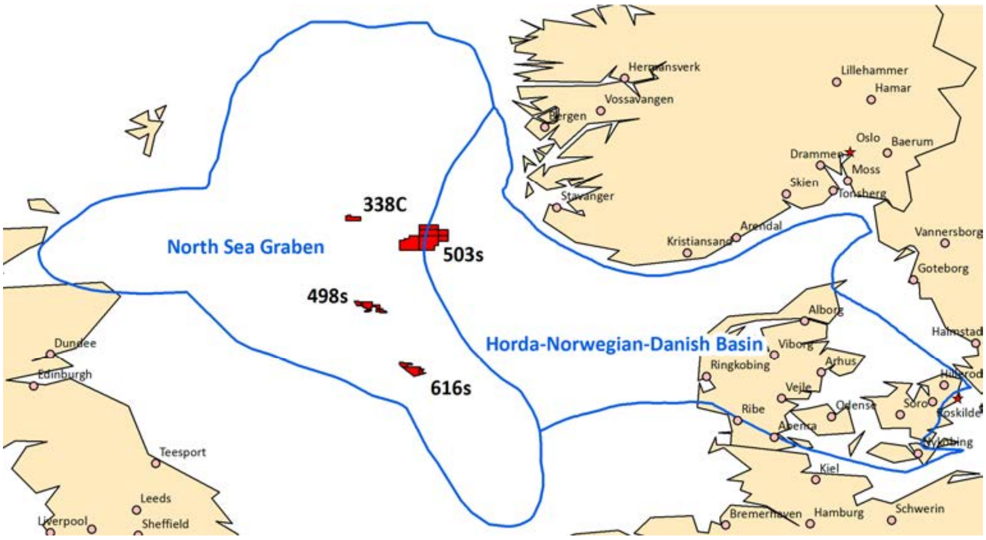
The geological history of the NSGP is dominated by an episode of late Jurassic to earliest Cretaceous crustal extension, which developed a number of distinct sub basins, principally identified as the: (i) Viking Graben Basin; (ii) Moray Firth Basin; and (iii) Central Graben basin (Figure 31).

Virtually all significant oil and gas accumulations in the northern North Sea are believed to have been generated within certain fine-grained, organic-carbon-rich marine strata of late Jurassic and earliest Cretaceous age. These Kimmeridgian shales accumulated in oxygen-starved rift basins and may locally thicken to 3,000m.

The actual source rocks are black shales that display high radioactivity and have total organic carbon ("TOC") contents of 2% to 15% or more and average about 5% TOC. The typical kerogen types within the hot shales are mixtures of organic matter commonly described as Type II kerogen, reflecting a mixture of planktonic marine algae and degraded terrigenous humic organic matter.

Figure 30 – North Sea Graben & Horda Basins

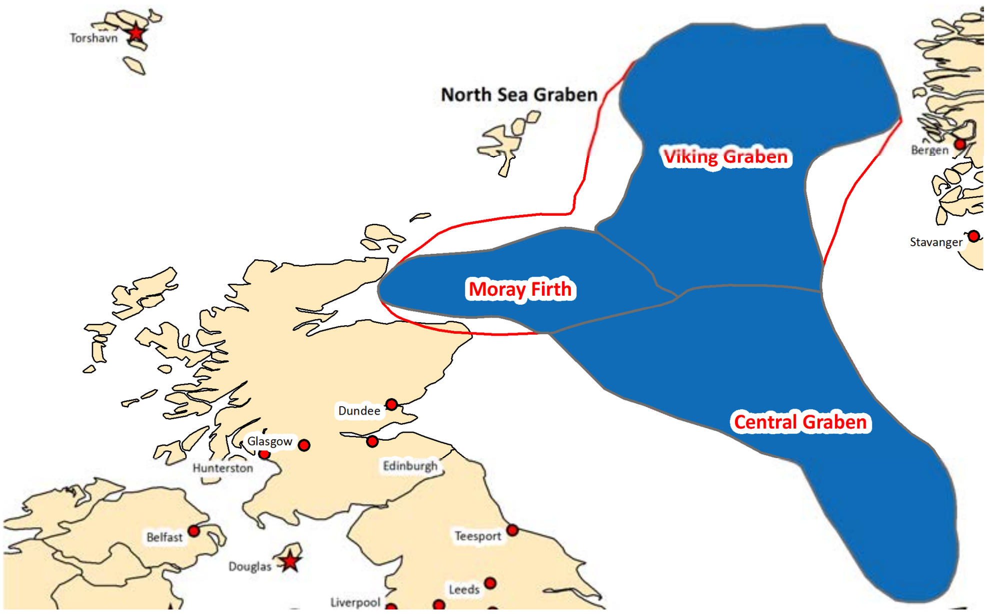
Schematic of the Principal Norwegian North Sea Basins



Source: USGS, NPD, ESRI & SPA data

Figure 31 – Sub Basins of the NSGP

Location of the Viking Graben, Moray Firth and Central Graben sub basins of the NSGP



Source: ESRI, USGS & SP Angel data

Burial of Central Graben source rocks has been more or less continuous from the time of deposition until the present day. Some source rocks achieved thermal maturity with respect to oil and gas generation as early as Late Cretaceous time and continuing to the present day in some areas. Thus newly generated oil and gas has been available to traps almost continuously during post-early Cretaceous Central Graben history. Locally, the continuous time-temperature process was interrupted by structural inversion, also in Late Cretaceous time.

The near-universal predominance of upper Jurassic marine shales as source rocks in the Central Graben has resulted in a wide variety of migration styles and pathways, including stratigraphically downward migration into pre-Jurassic reservoirs rocks in fault blocks.

Pre-rift rocks as old as Devonian, and including non-marine Carboniferous fluvial sequences associated with the Coal Measures, Permian Rotliegendes sandstones, Zechstein carbonates, and Triassic and lower Jurassic sandstones in fault blocks have been variously charged with hydrocarbons.

Middle and Upper Jurassic sandstones, deposited simultaneously with rifting in the Central Graben, form significant reservoirs for fields such as Fulmar and Ula. These syn-rift reservoirs include both shallow water and deep-water marine facies, evidently reflecting topography present during the formation of the Central Graben rifts.

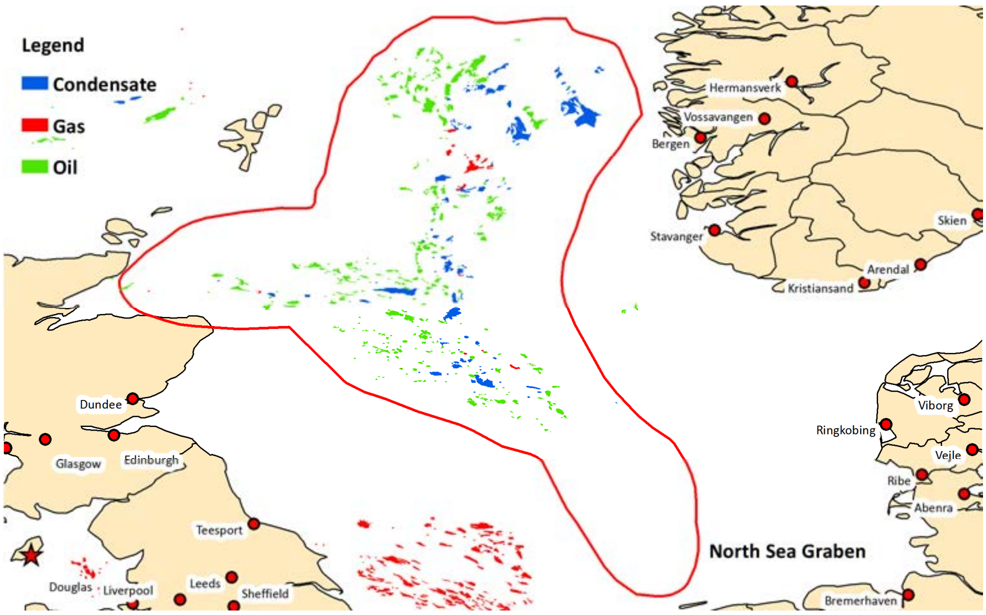
Lower Cretaceous reservoir sandstones are also present, having formed within the framework of the post-rift topography of the Central Graben. Chalk reservoirs dominate the Upper Cretaceous to lowermost Danian strata of the Central Graben. The most productive chalk reservoirs of the Central Graben occur in slump blocks and other structures associated with salt tectonics. Paleogene submarine fan complexes provide reservoirs for some of the most outstanding fields of the North Sea, including Forties.

Central Graben traps include fault blocks draped with Jurassic mudstones, Cretaceous chalk, or shale of Tertiary age. In contrast to the Viking Graben and Moray Firth, salt tectonics is responsible for much of the structural complexity that provides opportunities for hydrocarbon entrapment. Stratigraphic traps are dominant in the upper Jurassic and younger sandstones. Seals are Jurassic shale, Cretaceous chalk, or Tertiary shale.

The Central Graben contains a wide range of pre-, syn- and post-rift fields (Figure 32). Its pre-rift producing fields have mainly Palaeozoic or Triassic to Lower Jurassic reservoirs. Those having reservoirs of Palaeozoic (Devonian, Carboniferous or Permian) age are concentrated on tilted footwall blocks (e.g. Auk Field) associated with the major graben-bounding faults.

Figure 32 – Principal North Sea Fields

Map illustrating the main North Sea Graben fields



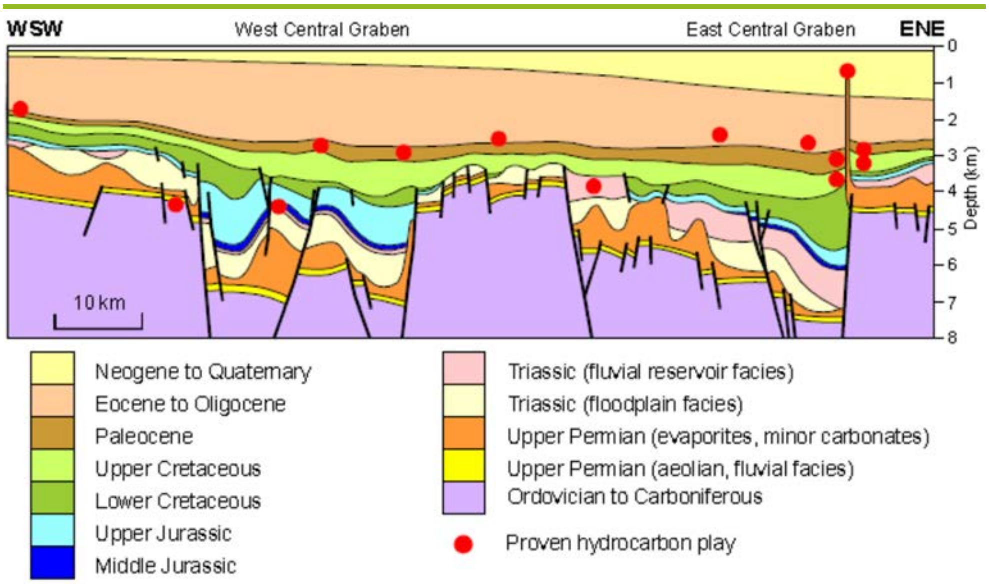
Source: DECC, NPD, ESRI & SPA data

The discovery, as recently as 1998, of the Flora Field, with its Stephanian-1 well, indicates that the Palaeozoic play has not reached maturity yet. Indeed, the reservoir potential of the Carboniferous strata remains underexplored.

The traps for pre-rift producing fields with reservoirs of Triassic to Lower Jurassic age are subcrop closures beneath syn-rift or post-rift strata (e.g. Marnock Field). The reservoirs are typically thick, highly feldspathic, fluvial channel and sheetflood sandstones. They are fine-grained on the western flank of the Central Graben, where they are partly confined to topographic lows that formed in response to halokinesis of underlying Upper Permian evaporites (Figure 33).

Figure 33 – Central Graben Cross Section

Schematic section illustrating principal under-explored plays in the Central Graben



Source: ESRI & SPA data

This has led to abrupt reservoir thickness changes, elongate patterns of net sandstone, and poor connectivity between adjacent sand systems. Reservoir properties are highly variable. Not all of the prospective structural or subcrop traps have been drilled as yet, and the potential for traps defined by reservoir pinch-out is under-explored.

Pre-rift Middle Jurassic clastic reservoirs in the Central Graben are associated with volcanic centres, and reservoir prediction is difficult. Nevertheless, there may be an opportunity for discovering untapped resources, because there is a likelihood that overpressure has preserved economic porosity and permeability to anomalous depths in the graben. The most attractive prospects may be those stacked below syn-rift targets.

The pinch-out of syn-rift, Upper Jurassic shallow marine and basin-floor sandstones at the margins of the Central Graben will continue to provide an attractive exploration target (e.g. Buzzard Field). Careful sequence stratigraphic analysis will be required to fully evaluate the distribution of shoreline facies reservoirs in this Mesozoic basin margin play.

Exploration within overpressured parts of the Central Graben has revealed that the basal syn-rift shallow-marine sandstones are more widespread than previously recognised. Identification of drilling targets will be more challenging here than around the basin margins, but careful sequence stratigraphic interpretation of 3D seismic data should yield further successes in this area.

Contemporaneous halokinesis is another factor affecting facies distributions in the Central Graben, and later halokinesis is also important as a trapping mechanism. Recent wells in the deepest parts of the Central Graben have extended the play fairway for thick, overpressured Jurassic syn-rift basin-floor sandstones into this area too. It is these sandstones that provide the gas reservoir for the recently discovered Jacky Field. Furthermore, recent drilling successes have demonstrated that substantial hydrocarbon resources still remain to be discovered on the hanging walls of the major faults of the region.

Up to 1,000m of post-rift Upper Cretaceous chalk accumulated in the Central Graben. The chalk has generally poor reservoir properties in the UK sector. Exceptions include chalk that has been redeposited by gravity flow processes at the base of oversteepened slopes, for instance around rising salt diapirs and around the graben margins. The potential for stratigraphic entrapment within porous redeposited chalk encased in non-porous sediment remains under-explored in basinal areas, but requires an effective migration conduit from underlying source rocks.

There is also a possibility that chalk porosity has remained anomalously high relative to depth of burial in overpressured areas of the Central Graben. Even where relatively porous, however, it has yet to be proven that significant resources remain to be discovered from chalk reservoirs in the UK sector of the North Sea. All of the existing fields (e.g. Joanne and Kyle fields) are in the south-east of the oil province. They are small and only marginally economic.

The Paleogene reservoirs in the Central Graben occur in both structural and stratigraphic traps. Structural traps are located mainly over pre-Tertiary structural highs (e.g. Forties Field), or are either flanking or overlying Permian salt diapirs (e.g. Andrew Field, Pierce Field).

Top seal is provided by regionally extensive mudstone intervals. Stratigraphic traps include mounded closures and sand pinch-outs, which can occur in a wide range of depositional settings. The pinch-out traps have a higher exploration risk of seal failure, although they have only rarely been tested in optimal drilling locations.

Norwegian Sea Province

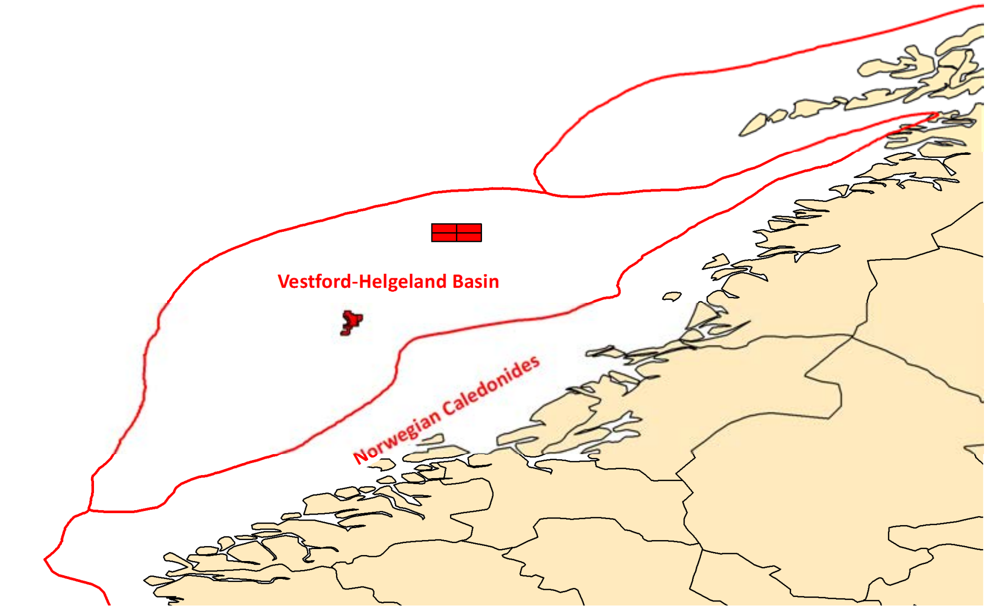
The Norwegian Sea Province ("NSP") is composed principally of the Vestford-Helgeland Basin, but also includes the Norwegian Caledonides, which extends beyond the NSP and covers most of the offshore area of the coast of Norway. The constituent basins in the NSP are illustrated in Figure 34.

Upper Jurassic marine shales equivalent to the Spekk Formation of the Halten Terrace and to the Kimmeridge Clay in the northern North Sea constitute the oldest readily identifiable stratigraphic marker on regional seismic sections. Although not drilled in the area of this assessment unit, this organic carbon-rich shale is expected to have similar hydrogen enriched, high TOC, oil-prone properties of equivalent rocks elsewhere in this area.

Estimated depths of burial and time-temperature integrals of the Upper Jurassic in most of the assessment unit indicate thermal maturity in excess of stability of oil in all but a few small areas in the area. Thus, resources are expected to be largely gas rather than oil. Thermal maturity is thought to have greatly increased in late Neogene time as a result of burial beneath glacio-marine sediments derived from the glaciation of the Scandinavian Shield.

Figure 34 – Sub Basins of the NSP

Location of the Vestford-Helgeland and Norwegian Caledonides sub basins of the NSP



Source: USGS, ESRI & SPA data

Migration is expected to have taken place from the Upper Jurassic source rocks into a variety of structural blocks formed during Mesozoic rifting and into various large inversion structures and myriad potential stratigraphic traps that can be expected to be widely distributed around.

A wide range of potential reservoir rocks include deeply buried clastic rocks as old as Devonian in rift-related fault blocks, Permian carbonate rocks, fluvial channel and deltaic sandstones of Jurassic age, and a variety of Cretaceous and Tertiary sandstones ranging from late Early Cretaceous to rocks as young as Oligocene.

Postulated seals and traps are analogous to those in the Halten Terrace, Trondelag Platform, and Viking Graben, consisting of lithologic permeability barriers in stratigraphic traps as well as seals provided by overlying marine fine-grained rocks in the case of structural closures.

While there has been limited exploration in the NSP, in comparison to the wider North Sea area, there has nonetheless been a number of commercial discoveries (Figure 35), which have served to maintain the interest in this underexplored hydrocarbon province.

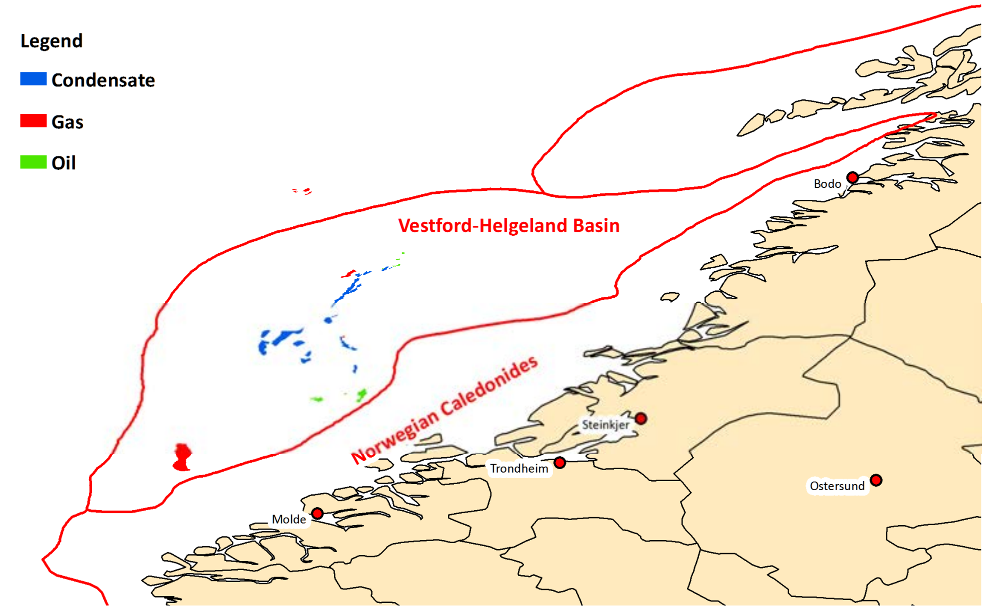
Barents Sea Province

The Barents Sea Province ("BSP") is located wholly offshore Norway's northern coast and contains several sedimentary basins separated by structural arches in the eastern part and a broad structural platform in the western part. There are 5 key structures, namely the: (i) Hammerfest-Varanger Basin; (ii) Troms-Bjornoya Basin; Central Barents Platform; (iii) Kola Monocline; (iv) Barents Continental Slope; and (v) Norwegian Caledonides. The BSP stretches in to Russian territorial water and is illustrated in Figure 36.

Analyses of petroleum and rocks from wells indicate sources of petroleum in Middle Triassic and Upper Jurassic mudstones, with possible contributions from underlying Palaeozoic and other Mesozoic rocks. Due to possible mixing of petroleum from differing source rocks, a single Palaeozoic-Mesozoic Composite system was identified for the East Barents Basins, Novaya Zemlya Basins and Admiralty Arch, and Barents Platform Provinces. Along the west margin of the shelf, source rocks include Jurassic, Cretaceous, and possibly Paleogene mudstones.

Figure 35 – Principal Norwegian Sea Fields

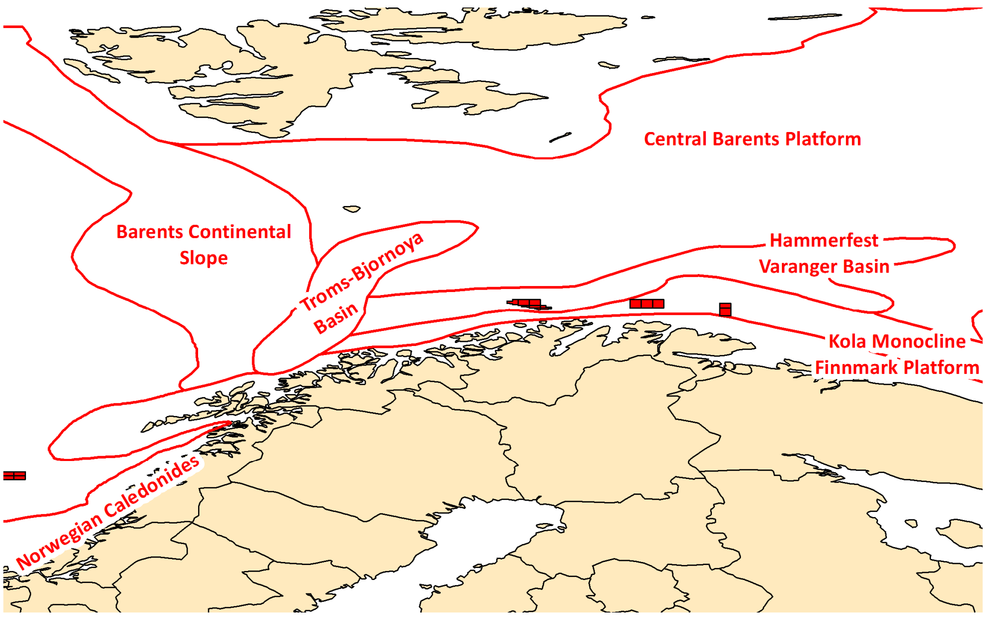
Map illustrating the main Norwegian Sea fields



Source: DECC, NPD, ESRI & SPA data

Figure 36 – Barents Sea Basins

Location of Barents Sea Basin and principal features



Source: ESRI & SPA data

Known reservoir rocks include Carboniferous to Permian, Triassic, Middle and Upper Jurassic, and Cretaceous and Paleogene sandstones, as well as Upper Permian spiculite. Potential reservoirs include upper Paleozoic carbonate rocks.

Known and inferred traps include structural highs with closures, fault-related structures, drapes over structures, stratigraphic onlaps and pinchouts along basin margins, carbonate-shelf and reef-associated deposits, stratigraphic traps (such as, submarine fans and channels), and salt structures.

The tectonic history of the Euro-Asian Arctic is anchored by the Early Proterozoic (Karelian) orogeny, which established the stable Russian-European platform adjacent to the Archean Baltic Shield. Accreted and superimposed, latest Proterozoic (Baikalian) orogenic trends are oriented NW-SE, exemplified by the Kanin-Timan Ridge and the Kola Monocline southwest of the Timan-Pechora and Barents Provinces.

Baikalian basement comprises the western and central Timan-Pechora Basin Province and possibly part of the South Barents Basin Province. Karelian (or younger, Grenvillian) basement is likely present in more northern regions.

The Early Paleozoic Caledonian orogeny largely closed the Cambrian Iapetus (old Atlantic) Ocean and consolidated the Laurentia (Greenland/North America) and Baltic (Euro-Russian) continental plates, primarily impacting the more western Barents Sea and possibly establishing tectonic trends northeastward into at least part of the North Barents Basin. A remnant of the old Iapetus oceanic basin could have been preserved in this eastern Barents region, according to some plate tectonic models.

Late Paleozoic (Devonian and younger) rifting and subsequent continental collision were recorded in the carbonate-to-siliciclastic stratigraphic succession along the southern margins of the South Barents Basin. Collisions of the Laurentia/Baltic plate with the West Siberian plate (Permo-Triassic “Uralian” orogeny and Early Jurassic “Early Kimmerian” orogeny) tectonically defined the eastern boundaries of the Barents and Timan-Pechora Provinces by creating the Ural and Novaya Zemlya foldbelts that supplied siliciclastic sediments westward to the foredeeps of the eastern Barents Sea and the Timan-Pechora Basin.

Eastern Barents subsidence and sedimentation rates were probably greatest during latest Permian and Triassic times. The Ludlov Saddle separating the South and North Barents Basins is Mesozoic in age, possibly as old as Triassic, and contains east-west trending anticlines and synclines.

The exact origin of the mostly Mesozoic eastern Barents basins and the age of the basin floors are uncertain. Remnant Cambrian (Iapetus) ocean floor might be present locally. Similar basins exist northeastward within the North Kara Sea. It has been proposed that Late Permian-Triassic rifting origin from mantle diapirism, which explains the gravity maxima. Crust of the basin centers is thin and oceanic, with basalts of presumed Late Paleozoic age and a typical Moho depth of 30km.

In contrast, surrounding platform areas contain additional continental crust to 15km in thickness above the basalts, with the Moho at an average depth of 45km. East Barents magnetic rocks are known or postulated to exist in the basement, locally within Devonian carbonates, in the basin centres as sills within Triassic siliciclastics, and in the northern regions of Franz Josef Land and Svalbard within Jurassic through Early Cretaceous rocks.

Cenozoic uplift associated with the opening of the Greenland Sea and the Arctic Ocean resulted in regional erosion ranging from probably hundreds of meters to several kilometres over the entire Barents Sea. Late Cretaceous and Tertiary rocks are generally thin to absent from the eastern Barents region.

Exploration history

Bathymetric studies, bottom samples and earliest seismic surveys in the Barents Sea were acquired during the 1960s, followed in the 1970s by more detailed seismic exploration and the acquisition of gravity and aeromagnetic data to nearly latitude 80° N. Some island drilling was accomplished during the 1970s, with Franz Josef Land and Svalbard containing wells to 3km depths. The first offshore location was tested in 1982/1983 at Murmansk field in the southern South Barents Basin.

More than 250,000km of eastern Barents seismic data have been acquired with spacings of up to 6km in the South Barents Basin and spacings of up to 40km spacing in the North Barents Basin; at least 30 major structures have been identified from these seismic surveys.

The deepest regional well was drilled to a depth of 4,524m in Lower Triassic rocks within the central South Barents Basin; Carboniferous limestones are the oldest rocks penetrated at 4,005m total depth in a well just east of these provinces on the Novaya Zemlya monocline.

Middle East Basins

The Company operates in 3 basins in the Middle East, namely, the: (i) Masirah Trough; (ii) Gulf of Oman and (iii) Rub al Khali (Figure 37). While all of the basins have a similar history, the geology of the Masirah Trough and Gulf of Oman is nominally identical.

Figure 37 – Middle East Regional Basins

Location of the Masirah Trough, Gulf of Oman and Rub al Khali Basins in the Middle East Basin Region

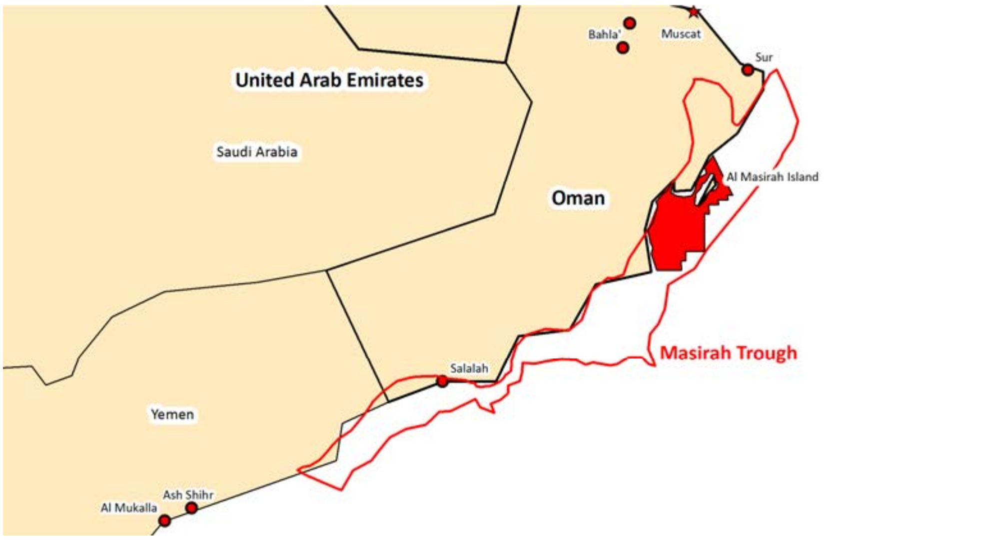
Source: USGS, ESRI & SPA data

Masirah Trough

The Masirah Trough is located primarily offshore of the southern area of Oman (Figure 38), stretching from Sur (in the north) to Ash Shihr in the south; the basin also encompasses Masirah island.

Figure 38 – Masirah Trough Basin

Map showing the location of the Masirah Trough Basin



Source: USGS, ESRI & SPA data

Oman is located on the southeastern margin of the Arabian plate and is close to the boundaries of the Iranian, Indian, and African plates. Consequently, plate movements have resulted in complex structural, sedimentation, and burial histories.

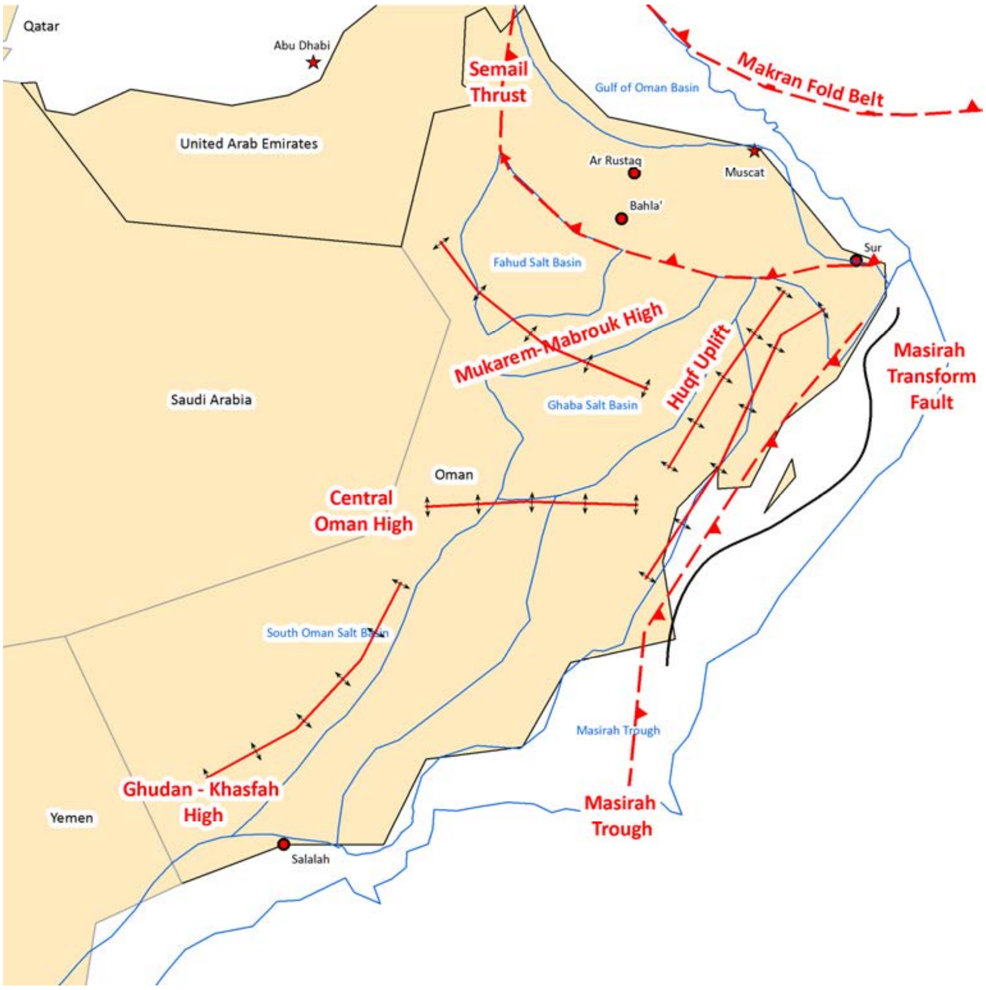
Oman is tectonically bounded on the south by the Gulf of Aden spreading zone, to the east by the Masirah Transform Fault and the Owen Fracture Zone Trough, and to the north by the complex Zagros-Makran convergent plate margin, compression along which produced the Oman Mountains. Precambrian metamorphic and igneous basement rocks are known from a limited number of wells and from exposures of bedrock along the Huqf-Haushi Uplift on Oman's eastern margin.

Orogeny

During the Late Precambrian period, Oman and its surrounds underwent accretion and collision, followed by an extensional phase of deformation. It appears that the Huqf uplift has been a long lived, large-scale, feature that has controlled the sedimentation towards the east in the basins of Oman (Figure 39).

Figure 39 – Key Omani Basins

Structural elements and basins of Oman



Source: USGS, AkerGeo, ESRI & SPA data

The Huqf high, probably, was the eastern boundary of the Infracambrian–Cambrian Oman salt basin. In the western flank of the Huqf uplift there are outcrops of Permian-Carboniferous rocks and striations in older rock units resulting from glaciation. The Huqf uplift may have also acted as a barrier to the deposition of upper Paleozoic sediments to the southeast of the arch, where wells drilled east of the uplift have not penetrated rock units between the ages of Infracambrian to Jurassic.

It is possible to ascertain that during the transition from the Pre-Cambrian to Cambrian, the Pan-African collisional tectonics changed to an intra-continental extensional tectonics and the Infra-Cambrian rocks overlies unconformably the deformed Pre-Cambrian rocks.

The opening of the NE-SW oriented basins was linked to major left lateral strike slip faults oriented NW-SE across the Arabian Peninsula. Along the NE-SW oriented extensional basins there were right lateral strike movements along the normal faults.

Following the rifting event, the Tethys Ocean gradually encroached onto the southeastern corner of the Arabian Peninsula reaching the fringes of the Masirah Graben and stepwise flooding the area. The depositional sequences consists of the predominantly clastic sediments of variable thickness (Abu Mahara Group) at the base, to more uniformly stratified clastic deposits and platform carbonates of the Nafun Group at the top.

The Abu Mahara Group is poorly resolved from seismic data, but, it has been partly penetrated by wells and studied in outcrops in the Huqf, Jebel Akhdar, and Mirbat areas. Thickness variations in the Abu Mahara Group suggest that, during deposition of the Ghadir Manqil Formation, a NE-SW trending rift basin developed in eastern Oman. The sedimentary facies variations suggest that during the deposition of the Abu Mahara Group there was a relief created by NE-SW trending horst-and-graben and basement highs may have developed separating different basin segments, maybe the Huqf uplift was at that time already a basement high.

The rifting event was locally associated with igneous activity and was followed by a thermal subsidence in the basins with deposition of siltstones, sandstones, stromatolitic carbonates and source rock of the Masirah Bay Formation.

The Nafun Group consists of two sequences of platform carbonates the Khufai and Buah Formations, separated by a sequence of mainly fine clastics of the Shuram Formation. Thickness and facies variations in the Nafun Group appear to be much less pronounced than in the underlying Abu Mahara Group sequences.

A relatively quiet tectonic period with absence of volcanics and coarse-grained clastics characterises the deposition of the Nafun Group that probably was controlled by eustatic sea level changes during a late phase of thermal subsidence following the Abu Mahara rift event. After this relatively tectonic quiet period, the Abu Mahara rift trend was reactivated, volcanism and the sedimentary sequences of carbonates, thick salt and the organic rich shales of the Athel source rock suggests renewed tectonic activity and subsidence during the deposition of the Ara Group (Upper Huqf).

The existence of a salt basin east of the Huqf uplift that can be time equivalent to the Oman salt basins is speculative. However, it is important to note that the SMPA-1 well, drilled in the southern Masirah graben penetrated 2,500m of Infracambrian sediments; this thick section of the Huqf Group may indicate the presence of another Infracambrian basin east of the Huqf uplift.

An unconformity separates Infracambrian sediments from Jurassic sediments in the Masirah Graben. It is not known if Paleozoic-Triassic sediments were not deposited or if they were eroded by successive events ending at the Triassic extension when a rift basin was probably formed at the site of the Masirah Graben.

There is no direct evidence for sedimentation in the Masirah area until the Jurassic, but, the presence of Permian to Cretaceous blocks in the Batain melange suggests that Paleozoic-

Mesozoic sediments were present in northeastern Oman. Basement granite blocks in the ophiolites suggest basement was eroded from beneath the Permian.

During the Triassic extension in the Tethyan rift domain, rifting and faulting created the conditions that resulted in the deposition of Jurassic and Lower Cretaceous shelf carbonates in Oman. This phase is represented by the Jurassic Sahtan Group and Khamah Group penetrated by wells in the Masirah graben. These rocks are similar in age to the Upper Jurassic Shuqra-Sabatayn formations of Yemen, and the Upper Jurassic Arab-Hith formations of central Arabia.

From the Aptian to the Cenomanian, the general sea level rise and flooding of the basins resulted in the deposition of the Nahr Umr Formation shale unit, the Nahr Umr Formation and the Lower Cretaceous Wasia Group were penetrated by wells in the Masirah graben.

During the Campanian the Hawasina and Semail nappes were obducted towards the southwest in northeastern Oman. Following this obduction, in latest Maastichtian to Paleocene times the Batain Complex was obducted in southeastern Oman, coeval with the northwestern directed obduction of the eastern ofiolite belt. The location of the Arabic paleocontinental margin is now hidden beneath the obducted allochthonous sediments.

The Cretaceous/Tertiary evolution of the Masirah graben and adjacent Huqf uplift has been illustrated in Figure 40. The Late Cretaceous to Paleocene age for the formation of the ophiolites indicates that sediments A-B are most likely of Upper Cretaceous age and that the Batain/Hawasina ophiolites were obducted in a large thrust sheet overlying layer A. The overthrust direction was to the west-northwest, and involved imbricates branching from a basal detachment above layer A.

Extensional faults appear to have been active during the Eocene in the eastern part of the Huqf uplift. The faults were reactivated and the footwall of the Huqf/Jebel Ja'alan block was further uplifted and tilted.

During the later Paleogene or Neogene, there was subsequent inversion of the faults surrounding the Jebel Ja'alan/Huqf uplift, folding of the Tertiary sediments, and overthrusting of the ophiolites. The transport direction was to the northwest, so the main Jebel Ja'alan/Huqf fault zone was reactivated as an oblique-slip fault with a left-lateral and reverse sense of motion. The original fault system was of a normal sense of motion and formed the western margin of the Masirah graben.

Tectonics

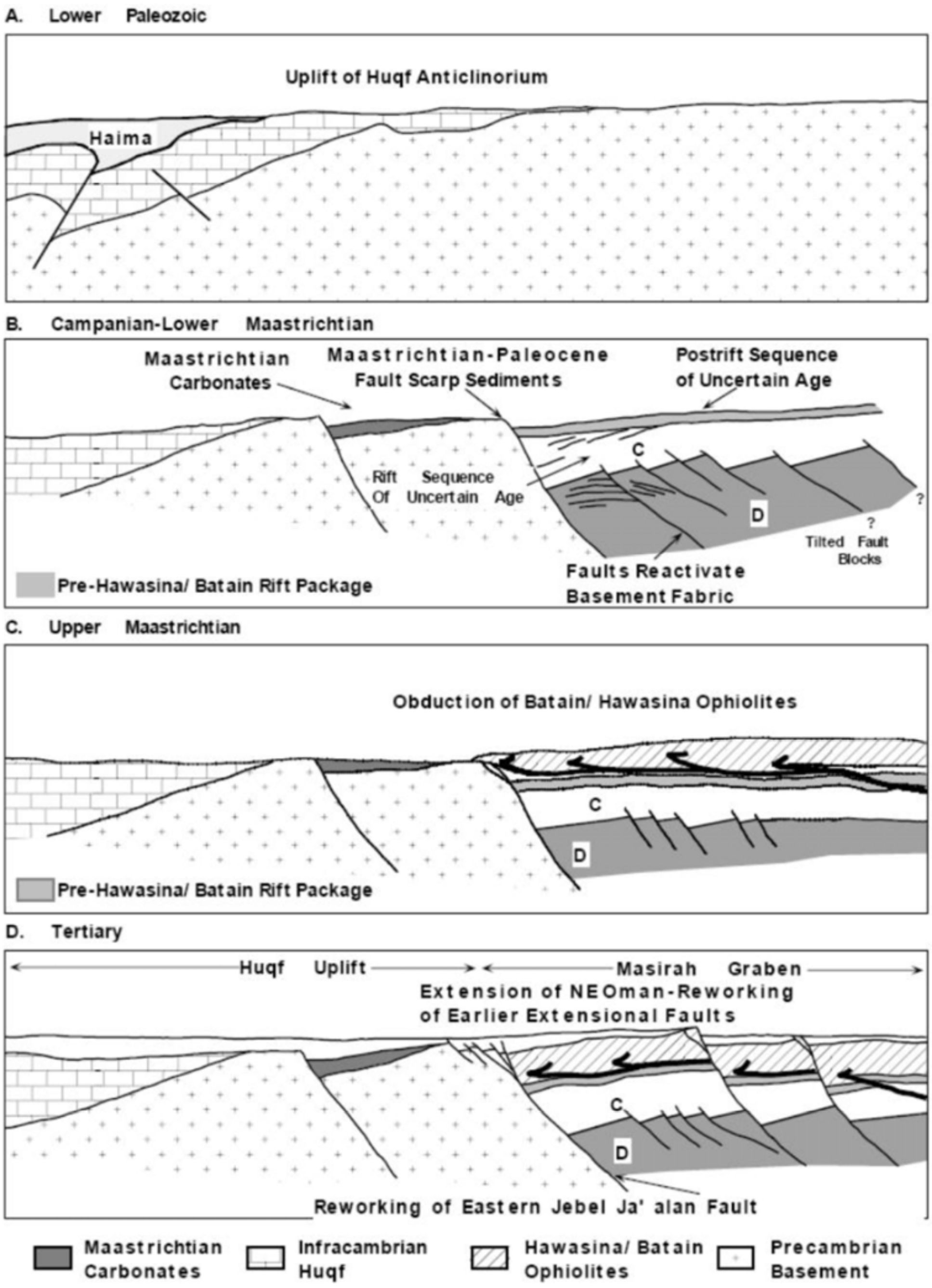
The present day plate boundary between the Indian and Arabian plates is located along the Owen Ridge, however, initially the Indian-Arabian plate boundary was located further west, along the Oman continental margin. Probably, during the re-organisation of the plate movements in the Oligocene-Miocene, the plate boundary moved to the present location and movements further west ceased.

The present primary plate boundary structure is not the bathymetrically high Owen Ridge, but is instead a series of clearly delineated right lateral strike-slip fault segments separated by several releasing and restraining bends. Despite abundant sedimentary supply by the Indus River flowing from the Himalaya, fault scarps are not obscured by recent deposits and can be followed over hundreds of kilometres, pointing to very active tectonics.

The total strike-slip displacement of the fault system is 10 – 12km, indicating that it has been active at least for the past 3 to 6mm years. This has been interpreted by high resolution multi-beam echo sounder data and described the geometry of this recent fault system, including a major pull-apart basin.

Figure 40 – Masirah Graben

Tectonic evolution of the Masirah Graben



Source: USGS, AkerGeo, ESRI & SPA data

The value of this analysis for us is to illustrate the possible analogous structures along the ancient plate boundary domain dominated by a left-lateral strike-slip wrench tectonics with the passage of the Indian continent towards its present position. The change of left-lateral to right-lateral movements probably occurred in Tertiary times during the opening of the Gulf of Aden-Sheba ridge zone.

In addition to this large scale, transform margin, plate tectonic forces that formed structures in the Masirah Basin there are other components of the stress regime that have to be considered as contributing or enhancing the structures in the basin. Three major tectonic events with different stress regimes have influenced the structuration in the Masirah Basin.

In the Late-Cretaceous obduction of the Hawasina Complex and Semail Nappe induced a southwest verging compression. In the latest Cretaceous to Early Paleocene obduction of the Batain complex and the Masirah ophiolite coeval to the opening of the Gulf of Aden, led to a NW-verging complex transpresional and transtensional stress regime that could have caused E-W oriented oblique normal fault formation. Lastly, the Miocene Alpine orogeny that resulted in growth of the Oman Mountains had a southwest oriented compression.

Source Rocks

Onshore Oman is a mature exploration province, with well-known petroleum systems. It is a widely held belief that to find new resources it will require the search for opportunities beyond the known hydrocarbon provinces, which in turn are considered to have significant charge risks.

Source rocks in Oman are multiple, generally rich, and fairly widespread marine sequences. They are predominantly oil prone, and most of the gas found is interpreted to result from thermal cracking of liquid hydrocarbons trapped in deep reservoirs and retained in source rocks.

Existing data show that Mesozoic and Cenozoic kitchen areas are restricted to western north Oman, the only areas currently buried at their maximum temperature. Large parts of north and central Oman depend on lateral migration from these kitchens for their charge. Progressive uplift of the east flank and basin inversion since the middle Paleozoic provides favourable conditions for long-distance migration in the post-Carboniferous interval. In central Oman, geochemical data suggests that a north-south–trending, reactivated basement grain has funnelled charge up to 300km southeastward.

Charge risks increase in the deeper sequence, in which eastward migrating hydrocarbons have to traverse the Ghaba salt basin, a pronounced syncline at depths greater than 3 km. The south Oman salt basin is currently cool because of shallow depths and hydrodynamic fluid flow activity. The shallow post-Cambrian reservoirs rely on storage of early (Cambrian–Ordovician) charge by the Ara salt (Cambrian) sequence, followed by release of hydrocarbons as the salt edge retreats through time.

Geochemical analyses of oil stains from the SMPA 1 well that were found at two levels in the Infracambrian (1811– 1905 m and 1985–2042 m depth) showed that the oils have identical properties and the analyses produced results comparable to published data. The results of the analyses of oils from the two zones suggested that the SMPA 1 oils were not sourced from the Infracambrian. The oils appear to be normal salinity marine and clastic sourced from a relatively aerobic depositional environment. The oil analyzed in the SMPA 1 well is mature on the basis of biological marker ratios, probably from a peak to late-mature source.

Although the exact source cannot be determined, it is most likely not an Infracambrian or Q source rock. This points to a younger sedimentary section as a source (Mesozoic–Jurassic), presently off structure from the area of the SMPA 1 well. The most similar sourced oils described elsewhere in Oman are those attributed to the regionally known Jurassic Sahtan Group (Diyab Formation).

This Jurassic source was not present in the wells of the Masirah trough, but was inferred by correlation of oil types from northwestern Oman, the United Arab Emirates, and Qatar.

These oils also have some affiliations to the Silurian Safiq sourced oils, but the correlation is better with the Jurassic source. This might also imply the existence of a precollision Cretaceous rift basin because such a basin would have been necessary to generate a Mesozoic oil for migration into existing structures in the Masirah graben.

The Mesozoic carbonate basins of the Arabian plate are one of the most prolific hydrocarbon provinces of the world. The outstanding features of these petroleum systems are the presence of source rock, reservoir, and seal facies within the same depositional system. The repeated cycles of development of organic-rich shallow basins upon the Arabian plate assured that significant source rock accumulations lay adjacent or in contact with potential reservoir facies.

For example in the Jurassic succession, the organic-rich source rock of the Hanifa Formation is partly interfingering, partly overlying Arab Formation. In the Cretaceous, the Aptian organic-rich deposits of the Bab basin are time equivalent to the adjacent Shuaiba reservoirs and the Cenomanian, organic-rich intrashelf basins were formed at the time of deposition of the Mishrif and Natih reservoir facies.

Whether the Mesozoic carbonate basins of the Arabian plate have an equivalent in the area of the Masirah graben it is not known, however, it is possible to speculate that in Jurassic to Cretaceous time the area of the Masirah graben was part of a shallow water embayment formed by Triassic rifting at the fringes of the Tethys Ocean.

In such a setting it is possible to visualize the development of a carbonate depositional system (confirmed by the Masirah wells) where restricted water circulation favoured the deposition and preservation of organic rich carbonate muds that could become source rocks in depositional settings similar to the basins on the Arabian Platform or the Persian Gulf.

Reservoir Rocks

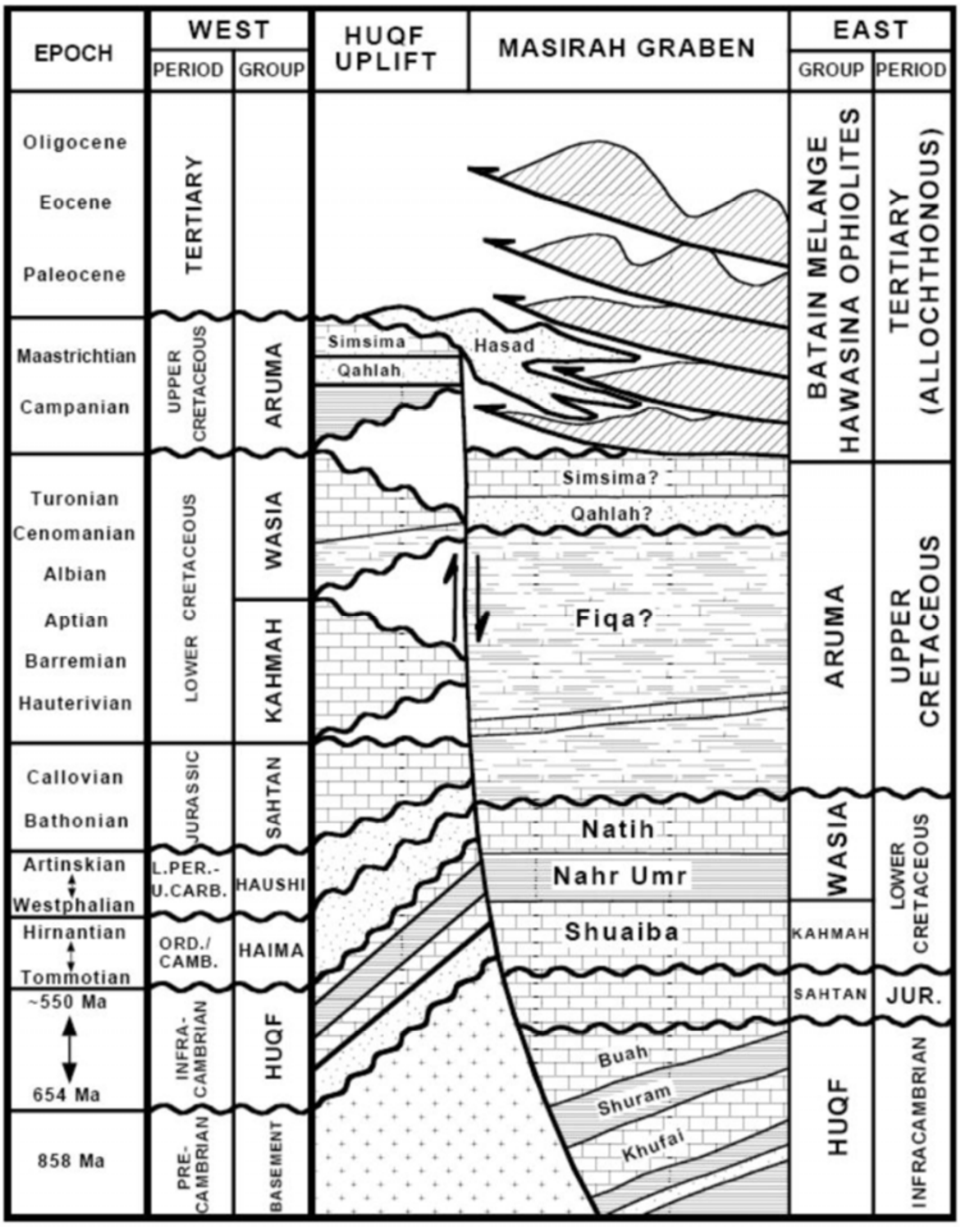
The SMPB 1 ended in the Infracambrian Huqf Formation after penetrating ~2,300m of Mesozoic–Cenozoic sediments composed of carbonates of the Lower Cretaceous Wasia Group/Natih Formation and the Lower Cretaceous Khamah Group/Shuaiba Formation. These shallow water carbonates composed mainly of oolitic and fossiliferous grainstones-wackestones separated by dense evaporitic had well preserved porosity of up to 25%. The porous intervals of the Lower Cretaceous Natih Formation were absent in the SMPA 1 well, probably removed by erosion in the Late Cretaceous or otherwise not developed. The general stratigraphy of the Masirah Graben is illustrated in Figure 41.

The differences in the thickness of these intervals between wells SMPA 1 and SMPB 1 may represent differential subsidence in the Masirah graben. The shallow-marine Lower Cretaceous Khamah Group is separated from the Lower Cretaceous Wasia Group by a regional flooding surface and deposition of the Nahr Umr calcareous shales. This sequence is similar to those recognised elsewhere in Oman and the United Arab Emirates.

The Jurassic sedimentary rocks penetrated in the SMPA 1 and SMPB 1 wells ranged from Bathonian to Callovian in age based on biostratigraphy. The Jurassic was composed of dolomites consisting of micritic mudstones. The Jurassic carbonates were not reservoir quality in the SMPA 1 or SMPB 1 wells.

Figure 41 – Stratigraphy of the Masirah Graben

The décollement surface of the Batain mélange and ophiolite nappes is interpreted as the Aruma Group



Source: AAPG & SPA data

For the Infracambiran, postulated characteristics of the Abu Mahara and Nafun Group can be summarised as follows:

- The Abu Mahara consists of mixed continental and marine siliciclatics. Large thickness variations (few 10's to 1000m). Poor reservoir quality (preservation of porosity and reservoir continuity is at risk); most likely productivity will depend on fractures.
    - Seal reliability is variable; depend on tight limestones and shales (shales are silty). Lateral seal across faults can be questionable.
    - Any mature Huqf source rock will be confined along the NE-SW trending deep basins. Abu Mahara source rocks are discontinuous with thickness of up to 50m and TOC of 3-5%.

    - Development of structures forming traps can range in age from Infra Cambrian to Tertiary.

- The Nafun Group (Kufai, Shuram and Buah Formations) are mixed carbonates and siliciclastic marine depositional environment. Preserved porosity is poor <10%. Secondary porosity is produced by diagenesis and development of vugs, connectivity can be poor and productivity will depend on fractures.

    - Seal depends on tight limestones, shales and top seal of the Ara salt (if present).

    - Source rock confined to rift basins. Huqf "Q" source or Athel, relatively thick (100's m and more than 1000m onshore) and TOC from 1 to 5%. Also possible charge from younger sources if large faults are present (i.e. well SMPA 1).

    - Development of structures forming traps can range in age from Infra Cambrian to Tertiary.

In general the Infra-Cambrian reservoir productivity will depend on interconnected and intersecting sets of fractures connecting the pore space. The rotating stress field created by transcurrent, extensional and compressional tectonic cycles from the Paleozoic to the Cenozoic probably have been of sufficient strength to fracture competent rocks.

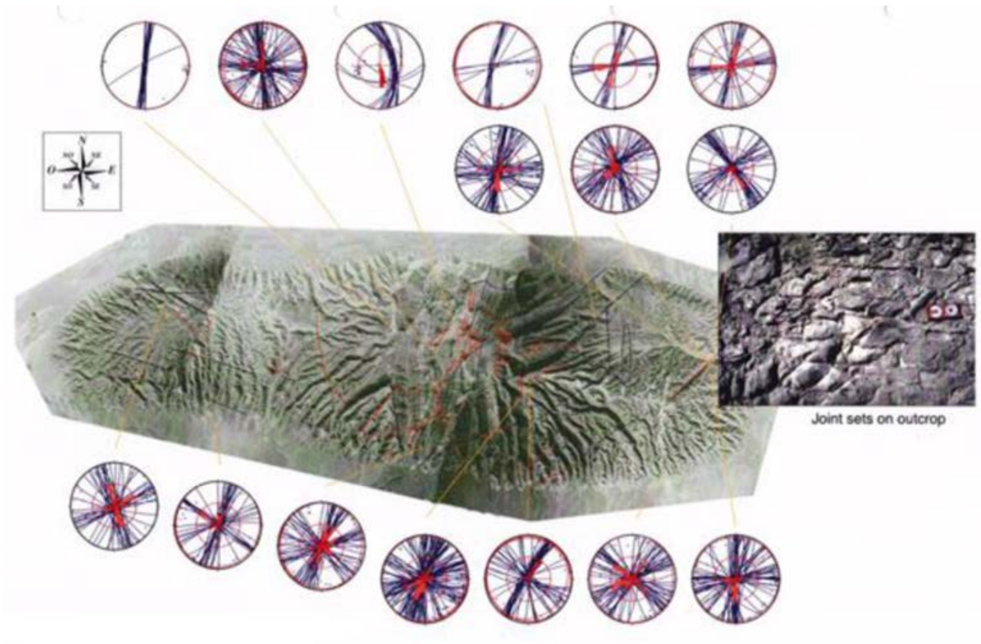
The SMPA 1 and the SMPB 1 wells had oil shows in cuttings and drill-stem tests from the carbonates of the Khufai Formation and the sandstones of the Abu Mahara in the SMPA 1 well. The shows in both formations were in poor-quality reservoir rocks. Drill-stem tests over intervals of the Khufai and Abu Mahara formations indicated low permeabilities and resulted in minor traces of oil associated with the acid water and cushion recovered.

Although no reservoir-quality rocks were encountered in the Huqf Group in either well, the carbonates of the Buah and the Khufai, as well as the sandstones of the Abu Mahara Formation, may be of reservoir quality elsewhere in the Masirah graben. These same-age (Infracambrian) rocks are proven reservoirs in the southern Oman salt basin west of the Huqf uplift.

The fractured carbonates of the Middle East contain some of the world's largest hydrocarbon reserves. Besides matrix permeability and porosity, reservoir quality is highly dependent on fracture distribution. The multiple tectonic events that occurred in the Mesozoic-Cenozoic have created a stress field variable in time direction and intensity, this has resulted in multiple fracture patterns that enhance the porosity-permeability and connectivity of the pore space in otherwise relatively tight rocks. As examples of fractures that could potentially be present in structures are illustrated in Figure 42.

Figure 42 – Oman Fracture System in Jebel Qusaybah

Fracture system in Jebel Qusaybah; circular pictographs depict fracture trends.



Source: AAPG & SPA data

Gulf of Oman

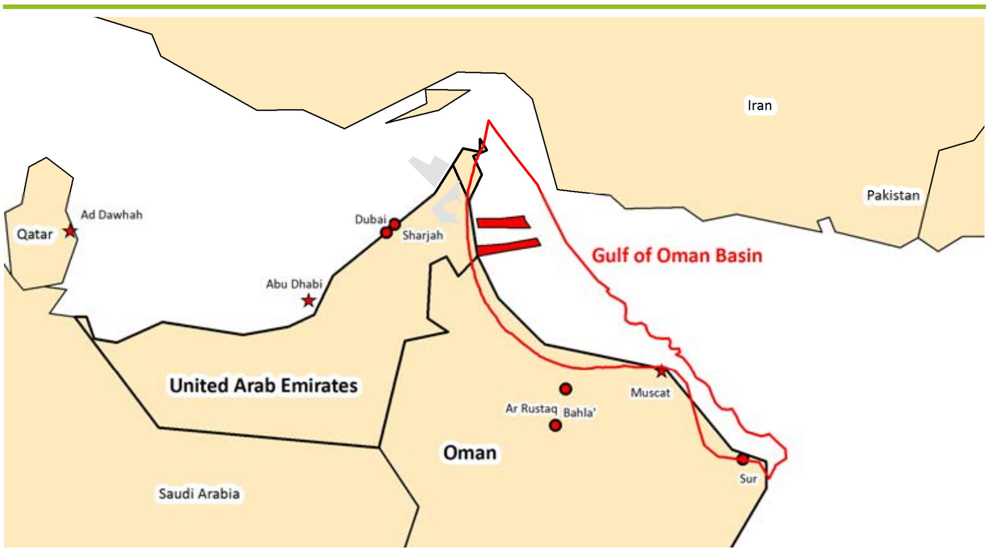
The Gulf of Oman basin is located in the north eastern coast of the Arabian Peninsula to the south of the Straits of Hormuz (Figure 43). Structurally, all of the basins in the Arabian Peninsula have undergone similar tectonic activity.

Orogeny

The tectonic events that led to the structural configuration of the Gulf of Oman Basin can be divided into four phases: rifting, sea-floor spreading, convergence and a divergence. The rifting phase probably began in Late Permian to Early Triassic time. It has been proposed that the blocky topography of the Oman continental slope formed during this rifting phase by listric faulting.

Figure 43 – Gulf of Oman Basin

Map showing the location of the Gulf of Oman Basin



Source: USGS, ESRI & SPA data

Rifting gave away to sea-floor spreading in Early Triassic time, and by Mid- Jurassic time an extensive southern Tethys developed in the region of the Gulf of Oman- Persian Gulf. At that time, deep- and shallow water carbonates were deposited on the graben fill and topped the topography of the fault blocks. In mid Cretaceous time, the sea-floor spreading and passive margin regime was replaced by transpression and later the obduction of a melange of pelagic sediments and volcanic rocks of the Hawasina and the Semail Ophiolite complex over the Mesozoic carbonates.

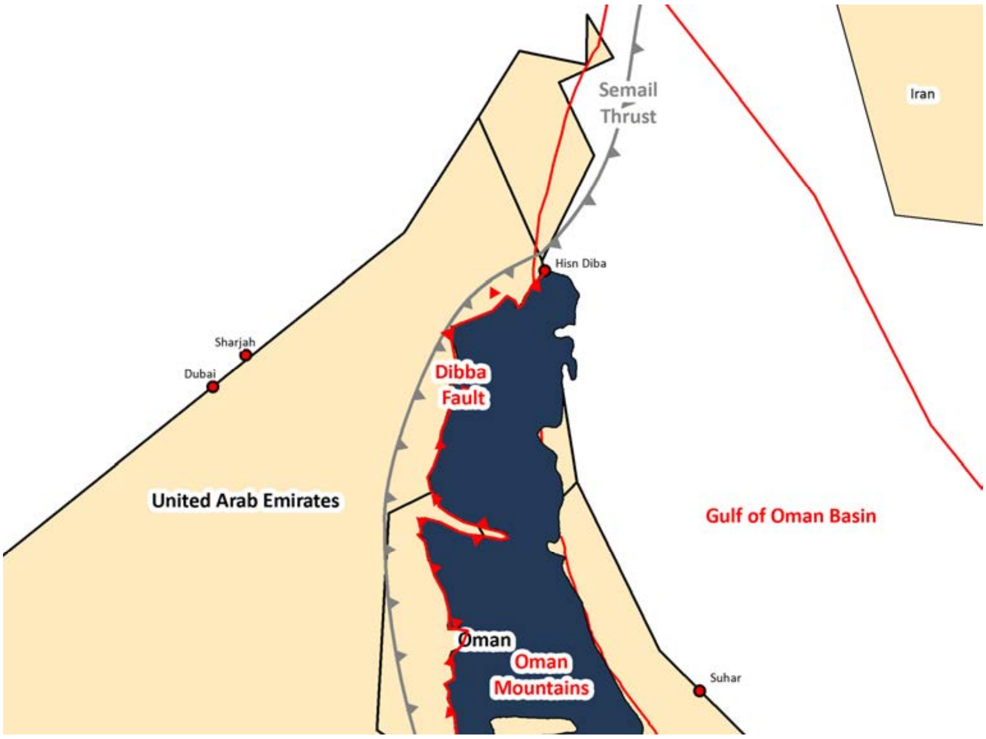
The margins of the Gulf of Oman Basin range from convergent at the north to translation at the west and east, and passive at the south. The basin's northern margin has been a site of continuous subduction since Cretaceous time, which has led to the creation of an accretionary wedge, most of which is above sea level.

Strata in the centre of the Gulf of Oman Basin display minor deformation resulting from the northward tilting of oceanic crust. A basin-wide unconformity dividing these strata in two was the result of erosion during Early Oligocene time when bottom water circulation was enhanced during a climatic deterioration. The morphology of the basin's south margin is the result of the Early Triassic rifting, deposition during Jurassic-Early Cretaceous time, early Late Cretaceous ophiolite obduction and Late Cretaceous-Cenozoic deposition.

The Mesozoic-Cenozoic accretionary wedge is truncated on the western side by the right lateral Zendan-Oman Line transform fault. West of the fault lays the Arabian Platform, the Musandam Peninsula, the Oman Mountains and the Dibba Fault (Figure 44). The Dibba Fault separates the ophiolites in the Oman Mountains from the Mesozoic carbonates in the Musandam Peninsula.

Figure 44 – Dibba Fault

Map showing the location of the Dibba Fault



Source: USGS, AkerGeo ESRI & SPA data

The Musandam Peninsula and Oman Mountains were formed by Mesozoic platform carbonate accretion and the obduction of oceanic crust and ophiolites in Cretaceous time.

Study has illustrated that the region between the Zendan Fault-Oman Line and the Dibba Fault is one of continental collision and that oceanic crust is restricted to the area southeast of the Zendan Fault-Oman Line. Subsequent study has revealed magnetic reversals in the region between the Zendan Fault-Oman Line and the Dibba Fault suggesting that parts can be underlain by oceanic crust.

Sedimentary strata in this region have been deformed during the Late Mesozoic-Cenozoic into a series of north-south trending ridges parallel to the Oman coast; between these ridges there are deposits of Paleocene to Lower Miocene turbidites.

Paleogeography

A number of paleogeographic and paleofacies maps have been compiled to reconstruct the depositional history of the Arabian Plate from Late Permian to Holocene in an attempt to mitigate the primary concern, namely the deposition of suitable source rocks in the Sharjah Area. It appears that other aspects, as deposition such as suitable rocks to become reservoirs and seals are less critical than the forming and preservation of source rocks.

Late Permian

In the Late Permian, continental rifting and spreading took place along the present-day Zagros Suture and Gulf of Oman as the Neo-Tethys Ocean started to form. Short-term sea level oscillations caused recurrent shoaling pulses that culminated in the establishment of evaporate sabkhas and salinas particularly over the Central Arabian Arch.

In the Late Permian, a shallow-marine carbonate platform (Khuff and Saiq formations) was established over most of Oman. This transgression was the result of subsidence of the northeastern Oman margin. Near Muscat, a rifted shelf margin with horst and graben structures developed.

Condensed carbonate successions are present on the horsts, whereas thick melanges of clastics, conglomerates, and olistoliths occur in the troughs. Offshore along the outer shelf break, higher energy calcarenites formed. The outer belt at the edge of the Arabian Plate margin was rimed with reef-like carbonate build-ups and detrital carbonates. Abyssal (hemipelagic) carbonates developed in Fars and on the Gulf of Oman-Makran slope.

The development of a petroleum system in Permian rocks in the Sharjah-Fujairah Area is entirely speculative and of little practical value because of the depth of burial. Only a process of re-migrated gas could be of any significance for prospects within the reach of drilling.

Triassic

During the early to mid-Triassic, the Arabian Plate persisted as a relatively peneplaned east-northeast sloping passive margin platform. During this period the deposition of the Sudair Formation (Saudi Arabia, United Arab Emirates, Oman) and the Mahil Formation of Oman took place. In the Rub' Al-Khali Basin gypsiferous shales predominated (Sudair Formation) and gave way eastward to shallow-marine carbonates (Mahil Formation of Oman). The eastern shelf-break that developed in the Late Permian remained as a flexure with horst and graben structures.

In the Late Triassic, a second phase of Neo-Tethyan extensional tectonics occurred in the eastern part of the Arabian Platform. This caused drowning of the northeastern margin, and localised volcanic activity on the continental slope. This second subsidence event had an important effect on the restructuring of the Hawasina Basin and it is assumed that the basement of the Hawasina Basin was thinned continental.

It is possible that in mid Triassic time the northeast flank of the Arabian Platform was a sloping platform where shallow-marine shales and carbonates were deposited and a flood of siliciclastics was carried into the sea by a major fluvial system.

There are not well documented Triassic sources in Oman and there is not additional data that can be used to predict the existence of Triassic source in the Sharjah-Fujairah Area.

Jurassic

During Early Jurassic time In Oman, the long-lasting Sahtan group was a gradually shoaling carbonate sequence that had a thin, basal transgressive succession of mixed terrigenous clastics and carbonates. In mid Jurassic time sediments were deposited in an open-marine environment, as the Arabian Plate now had passive margins to Neo- Tethys to the northeast and north. This was a time of a general phase of sea level rise. Coastal and near shore environments are represented by coastal sands that pass eastward into shallow-marine shales and then into shallow marine detrital carbonates.

In Oman, the shallow-water limestones of the Middle to Late Jurassic Sahtan Group were deposited in the eastern part of the Rub' Al-Khali Basin. The present-day shore of the Gulf of Oman corresponds roughly to the Middle Jurassic paleoslope that passed into the Hawasina Basin off the continental margin. The slope has a fringe of submarine-fan sands. It is possible that the Dibba fault was already active in mid Jurassic time separating a deeper basin to the southeast from the main platform.

In the Late Jurassic to Early Cretaceous, intermittent uplift, coincident with the easterly tilt of the Oman plate margin, occurred due to incipient rifting and spreading in the Indian Ocean, with continental separation occurring at the end of the Jurassic. It appears that the Arabian basin was filled-in rapidly by organic detritus and shelf marginal calcarenite wedges (clinoforms) that produced the prolific Middle Eastern oil reservoir facies of the Hanifa, Jubaila and Arab formations.

In Oman, the NE-trending Dibba Fault clearly separates the western Gulf province from the complexly structured margin of the Hamrat Duru and Umar basins to the southeast. Here, high-energy, well oxygenated sediments such as reefs and detrital calcarenites, characterize the plate margin. Various types of debris flows covered the continental slopes of Neo-Tethys.

The widespread occurrence of conglomerates in Oman at the end of the Jurassic indicates a regional destabilisation of the shelf edge associated with the rifting of India from Arabia. It appears that, synchronous with a sea level rise, the rapid drowning of the northeast platform seems to have outpaced the vertical carbonate production and led to the accumulation of deeper-water, mud-dominated, chert rich facies.

Cretaceous

The Early Cretaceous time period spanned the deposition of the Yamama, Minagish, Habshan, and Rayda formations, and their regional equivalents. Relatively continuous sedimentation took place in Oman, but most other parts of the Arabian Plate were affected by a late Valangian unconformity.

The sediments were deposited on open platforms and within intrashelf basins of the Arabian Plate that was surrounded to the north, east, and south by passive margins. In the Hawasina Basin of northeastern Oman, cherty sediments characterize the sequence from Tithonian through Hauterivian. However, the Hamrat Duru Basin with a high carbonate generation rate contains hemipelagic limestones, whereas radiolarian cherts prevail predominantly in the proximal, shale-rich Al Ayn subbasin and the distal Duru subbasin.

The flanking platform of the Al Ayn sag had mainly shallow-shelf environments with reefs, winnowed oolitic and peloidal limestone belts, and a lagoonal to platform interior environment.

The depositional environment appears to have alternated between an inner-outer, proximal-outer, to deep-outer ramp conditions. The rudists in the Thamama Group indicate general shoaling phases reflecting an inner-ramp environment sloping into intrashelf basins with predominantly deeper-marine, fine-grained argillaceous and organic rich mudstones and lime packstones (in Qatar the Lekhwair Formation overlain by Kharaib Formation).

The transgressive Albian deposits reflect a rise in sea level. The gradually rising sea level that followed the pre-Albian unconformity caused the oscillating deposition of shale and carbonates. The Shu'aiba, at a location in the southern Rub' Al-Khali Basin, evolved from a moderately deep-water platform into a rudist-rimmed plateau that may be a spur of the Dibba Fault of Oman. The distinct biofacies belts allow subdivision into an open marine/basinal environment, followed by platform-rimming rudist banks, and finally back-bank to lagoonal environments.

In Cenomanian-Turonian time the prospective sediments of the Mishrif, Ahmadi, and Rumaila were deposited in the Arabian Peninsula that are contemporaneous with the Natih Formation of Oman). In the mid-Turonian a prominent unconformity was formed by the beginning of the ophiolite obduction along the eastern margin of the Arabian Plate.

The Late Cretaceous Fiqa (United Arab Emirates, Oman) formations and their regional equivalents were deposited within a compressive foreland basin setting following onset of mid-Turonian ophiolite obduction along the eastern margin of the Plate. A narrow NW-trending foredeep formed west of the rising orogen as a result of ophiolite obduction, the erosional products from the orogenic front were shed as flysch deposits into the foredeep where deeper-water marine conditions were present (e.g. Simsima and Shiranish formations).

Subsequently, the Oman Platform became submerged and a series of transgressions resulted. This setting lasted through the Maastrichtian with deposition of the Aruma and Simsima formations, the Aruma Formation overlies unconformably the Early Turonian rocks

Paleogene

This time period spanned the deposition of the Rus and Umm er Radhuma formations in the Arabian Peninsula and the Pabdeh Formation in Iran. The emerged and uplifted mélange and ophiolite complex was eroded and sediments were deposited in the remaining foredeep in the Arabian Plate to the west.

East of the Oman uplift, the eroded sediments were shed into the Gulf of Oman culminating with a maximum flooding of the basins in the Early Eocene. During the Eocene debris flows and turbiditic slope sediments were mixed with fine-grained basinal sediments in the foredeep. Basinal shales also accumulated in the Mahdi Basin and the Gulf of Oman.

In mid-Oligocene time a major erosional event was caused by a prominent sea-level fall developing an unconformity and sedimentary hiatus that affected much of the Arabian Plate. This unconformity is also present in the Gulf of Oman, and above the unconformity there are low stand wedges and submarine fans sourced from the uplifted Oman margin and deposited in Gulf of Oman. Probably, in the Sharjah-Fujairah Area the turbidites were deflected along north south- trending ridges that were formed during the preceding compressive events.

Onshore example of the tectono-stratigraphic relation of the Middle Cretaceous Wasia Group, the Fiqa Formation, the Hawasina thrusts and the Late Cretaceous-Tertiary basin in the Al Jaww Plain has been previously published.

Neogene

Between the prominent north south- trending ridges in the Sharjah-Fujairah Area there are also Paleocene to Lower Miocene turbidites that prograde southward. They can be rhythmically alternating sands, silts and shales or sandy shales and conglomerates of Late Miocene and younger age thickening southward. This progradation terminates eastward at the Zendan Fault-Oman Line transform.

At the end of the Pliocene, sea level was probably about 150m higher than at present, and the shorelines of this time are visible on the Arabian mainland. During the Late Pleistocene glaciation submarine erosion would have carved channels and erosional terraces in the Gulf of Oman.

Modern equivalent of the Tertiary turbidite systems are useful to visualize the possible setting and geometry of prospective siliciclastic plays.

Source Rocks

Mesozoic Source Rocks

In Oman there are two prominent Mezosoic families of oil-source relations: The first group corresponds to the Shuaiba/Tuwaiq Oil Family, originating from Late Jurassic (Callovian–Kimmeridgian) and Middle Cretaceous (Aptian) source rocks. The second group corresponds to the Natih Oil Family,derived from Middle Cretaceous (Cenomanian to Turonian) Wasia Group source rocks.

Shuaiba/Tuwaiq oils are sourced by type II/I marine source rocks. Both source rocks were deposited in intracratonic basins, which covered most of Abu Dhabi and extend into northern Oman. The TOC values measured in the UAE exceed 4 % by weight. In the foreland basin of the UAE, the TOC in the Thamama Group drops gradually and averages only 1.4 % near the Oman border where most of the organic matter is overmature, but, can have gas potential. Shuaiba/Tuwaiq oils are restricted to northwestern Oman and are present predominantly in the Late Jurassic Tuwaiq and middle Cretaceous Shuaiba formations.

The Natih oils are sourced by marine type I/II source rocks within the Natih Formation. Deposition most likely occurred in a restricted possibly oxygen-depleted intracratonic marine basin on the Arabian craton that was connected to the open (Tethys) ocean in the northwest.

The TOC values range up to 15%, but average around 5%. Hydrocarbon indices may be as high as 800 mg HC/g TOC (Terken, 2001). Nearly all Natih oil is reservoired within the Natih Formation itself. Deep-marine shales of the Late Cretaceous Fiqa Formation onlap its top and provide an excellent seal in most parts of north Oman. Natih oils are restricted to a small area in central north Oman, a distribution that is structurally controlled to the south by the peripheral bulge of the foreland basin and to the east by the deformed core of the Ghaba salt basin.

It is not straightforward to extrapolate Mesozoic source rock analogs of the Arabian Platform into the Sharjah-Fujairah offshore. However, accordingly to the paleogeographic setting and considering that the Dibba Fault zone could have played a role in creating a basinal setting with restricted water circulation it is plausible that source rock quality sediments were deposited in Jurassic-Cretaceous.

Even if there were not isolated or restricted basinal conditions, still it is possible that organic rich sources were formed and preserved on the outer shelf during for example the Turonian global anoxic event. A modern analog example of the “anoxic open ocean” is found today in the Indian Ocean. The upper continental slope of the Indian Ocean from the Gulf of Aden to the Andaman Islands is occupied by a very large and relatively shallow anoxic layer.

Wherever this layer impinges on the shelf and slope between 250 – 1,200 m abnormally high organic carbon concentrations (between 2 and 10%) have been observed. Organic carbon content on the shelf and other parts of the slope under oxic water is lower (between 0.5 and 1%). Similar observations were made in the Gulf of Oman.

Paleogene Source Rocks

Contemporaneous with these events on the Arabian Plate a well-defined NW-SE trending depression was formed parallel to the Zagros Suture, extending from Fars to Lurestan, during the Paleocene-Eocene and even Oligocene in Lurestan. This depression was bordered to the SW by platform carbonates covering most of the Arabian Gulf. To the SE, the depression was limited by the Fars Platform, where the shallow water dolomitic limestone of the Jahrum Formation was deposited.

In the depression a monotonous and thick (200 to 1,000m) sequence of grey marls, containing a rich planctonic fauna was deposited. Euxinic conditions prevailed in the central part of the depression during Middle/Late Eocene and even Early Oligocene in Lurestan. Source rocks of up 150 to 200m of organic-rich marls contain up to 11.5% organic carbon, elsewhere, the average TOC values vary from 3% in Fars to 7.5% in Lurestan.

The organic matter is mostly algal, with HI up to 500/650 g HC/kg C (Bordenave, 2002). Whether similar source rocks were deposited in the Eocene between the N-S ridges in the Fujairah-Sharjah area of the Gulf of Oman is speculative, but possible. Such source rock was assumed to be present and has previously been modelled; this study concluded that potential source rocks of Eocene-Early Oligocene are in the oil window and are capable to expel substantial quantities of oil. If this scenario is true then there is a significant upside potential in the Sharjah and Oman acreage.

Reservoir Rocks

The SMPB 1 ended in the Infracambrian Huqf Formation after penetrating 2285 m of Mesozoic–Cenozoic sediments composed of carbonates of the Lower Cretaceous Wasia Group/Natih Formation and the Lower Cretaceous Khamah Group/Shuaiba Formation. These shallow water carbonates composed mainly of oolitic and fossiliferous grainstones-wackestones separated by dense evaporitic had well preserved porosity of up to 25%. The porous intervals of the Lower Cretaceous Natih Formation were absent in the SMPA 1 well, probably removed by erosion in the Late Cretaceous or otherwise not developed.

The differences in the thickness of these intervals between wells SMPA 1 and SMPB 1 may represent differential subsidence in the Masirah graben. The shallow-marine Lower Cretaceous Khamah Group is separated from the Lower Cretaceous Wasia Group by a regional flooding surface and deposition of the Nahr Umr calcareous shales. This sequence is similar to those recognised elsewhere in Oman and the United Arab Emirates.

The Jurassic sedimentary rocks penetrated in the SMPA 1 and SMPB 1 wells ranged from Bathonian to Callovian in age based on biostratigraphy. The Jurassic was composed of dolomites consisting of micritic mudstones. The Jurassic carbonates were not reservoir quality in the SMPA 1 or SMPB 1 wells.

For the Infracambiran, postulated characteristics of the Abu Mahara and Nafun Group can be summarised as follows:

- The Abu Mahara consists of mixed continental and marine siliciclatics. Large thickness variations (few 10's to 1000m). Poor reservoir quality (preservation of porosity and reservoir continuity is at risk); most likely productivity will depend on fractures.
    - Seal reliability is variable; depend on tight limestones and shales (shales are silty). Lateral seal across faults can be questionable.
    - Any mature Huqf source rock will be confined along the NE-SW trending deep basins. Abu Mahara source rocks are discontinuous with thickness of up to 50m and TOC of 3-5%.
    - Development of structures forming traps can range in age from Infra Cambrian to Tertiary.
- The Nafun Group (Kufai, Shuram and Buah Formations) are mixed carbonates and siliciclastic marine depositional environment. Preserved porosity is poor <10%. Secondary porosity is produced by diagenesis and development of vugs, connectivity can be poor and productivity will depend on fractures.
    - Seal depends on tight limestones, shales and top seal of the Ara salt (if present).
    - Source rock confined to rift basins. Huqf "Q" source or Athel, relatively thick (100's m and more than 1000m onshore) and TOC from 1 to 5%. Also possible charge from younger sources if large faults are present (i.e. well SMPA 1).
    - Development of structures forming traps can range in age from Infra Cambrian to Tertiary.

In general the Infra-Cambrian reservoir productivity will depend on interconnected and intersecting sets of fractures connecting the pore space. The rotating stress field created by transcurrent, extensional and compressional tectonic cycles from the Paleozoic to the Cenozoic probably have been of sufficient strength to fracture competent rocks.

The SMPA 1 and the SMPB 1 wells had oil shows in cuttings and drill-stem tests from the carbonates of the Khufai Formation and the sandstones of the Abu Mahara in the SMPA 1 well. The shows in both formations were in poor-quality reservoir rocks. Drill-stem tests over intervals of the Khufai and Abu Mahara formations indicated low permeabilities and resulted in minor traces of oil associated with the acid water and cushion recovered.

Although no reservoir-quality rocks were encountered in the Huqf Group in either well, the carbonates of the Buah and the Khufai, as well as the sandstones of the Abu Mahara Formation, may be of reservoir quality elsewhere in the Masirah graben. These same-age

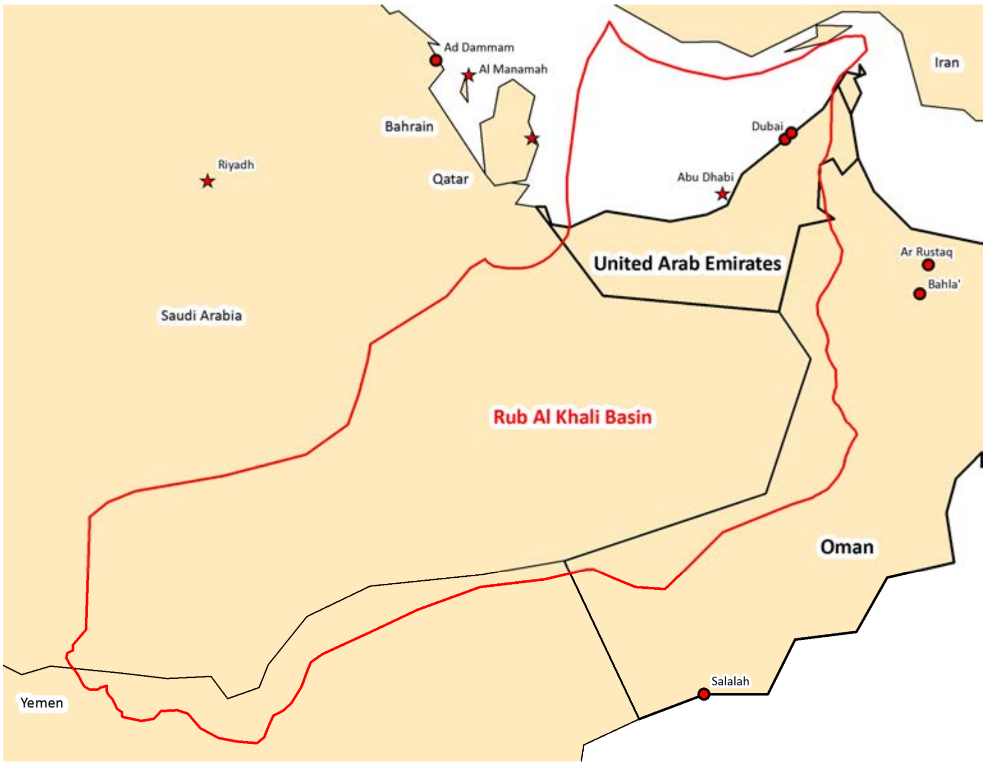
(Infracambrian) rocks are proven reservoirs in the southern Oman salt basin west of the Huqf uplift.

Rub Al Khali Basin

The Rub Al Khali Basin is one of the largest and most prolific hydrocarbon producing basins in the world. The basin itself covers almost the entire southern portion of Saudi Arabia and extends north eastwards into the Arabian Gulf encompassing northern Oman and the UAE (Figure 45); the basin gets its name from the desert of the same name.

Figure 45 – Rub Al Khali Basin

Location of the Rub Al Khali Basin



Source: ESRI & SPA data

Orogeny

The Arabian Peninsula has been subjected to significant orogeny, comprising of early continental rifting and block-faulting in the Mid-Permian and a later stage of rifting in the Late Triassic – Early Jurassic that led to continental break-up. During the early Mesozoic, the South Eastern region, where the UAE and Oman are presently, was part of a large carbonate platform on the rifted southern continental margin of the Neo-Tethys Ocean that by the end of the mid-Cretaceous became a mature carbonate basin.

At the end of the Late Cretaceous, the region was subjected to compressional deformation by the emplacement of a number of thrusts sheets migrating from east to west onto the Neo-Tethyan rifted continental margin. The obduction of the Semail Ophiolite and thrusts sheets loaded and flexed the underlying rift margin sediments forming the UAE foreland basin and the flank bulge.

The ophiolites and the thrust complex were intensely deformed; however, the underlying Mesozoic shelf carbonates were mildly deformed and faulted. But, these tectonic events caused uplift and erosion of the shelf carbonates and the development of the Turonian Wasia-Aruma unconformity that separates the rifted margin sequence from the overlying foreland basin sequence. The Upper Cretaceous foreland basin was infilled by an up to 4km Santonian – Campanian deep-marine mudstones of the Fiqa and Juwaiza formations.

The foreland infill is overlain by the Upper Maastrichtian to Palaeogene conglomerates and shallow-marine limestone of the Qahlah and Simsima formations and the basin remained stable until post-Middle Eocene time through the deposition of the transgressive Umm Er Radhuma Formation. The UAE foreland basin region was affected by a second compressional event during the Late Eocene − Miocene when the Arabian Plate moved northeastward, colliding with the Eurasian Plate. This event caused the reactivation of deep-seated faults in the frontal fold and thrust belt and adjacent foreland basin.

We describe the key intervals in the Rub Al Khali Basin below. Refer to the regional stratigraphic history (Figure 46).

Upper Jurassic

Diyab Formation (Callovian-Oxfordian)

In the early Late Jurassic active subsidence in the Arabian Gulf resulted in the development of intrashelf basinal sediments of the Diyab/Dukhan Formation that consists mainly of organic-rich, argillaceous lime mudstones and wackestones and constitutes source rocks. The Diyab Formation has a facies change toward the shallower parts of the basin, where it consists of limestones, slightly dolomitic with wackestone to packstone texture, grading upward to cleaner, sucrosic dolomite.

The progressive Jurassic flooding of the Arabian craton by a shallow sea ended in the Late Jurassic time with the formation of an extensive evaporitic platform over much of the area that had formerly been a shallow carbonate sea.

Late Jurassic sediments were deposited over a shelf that underwent periodic epeirogenic movements probably controlled by basement features. The widespread occurrence of four depositional cycles of the Arab/Hith Formations suggests also that this depositional cycles may be related to eustatic sea-level variations.

Arab Darb Formation

The Arab Formation can be subdivided into four members A, B, C and D. The dominant lithology of members A-C consists of limestone to mudstones with sucrosic dolomite, dolomitised pelletal wackestones to packstones, with thin stringers of peloidal grainstones separated by continuous anhydrite intercalations.

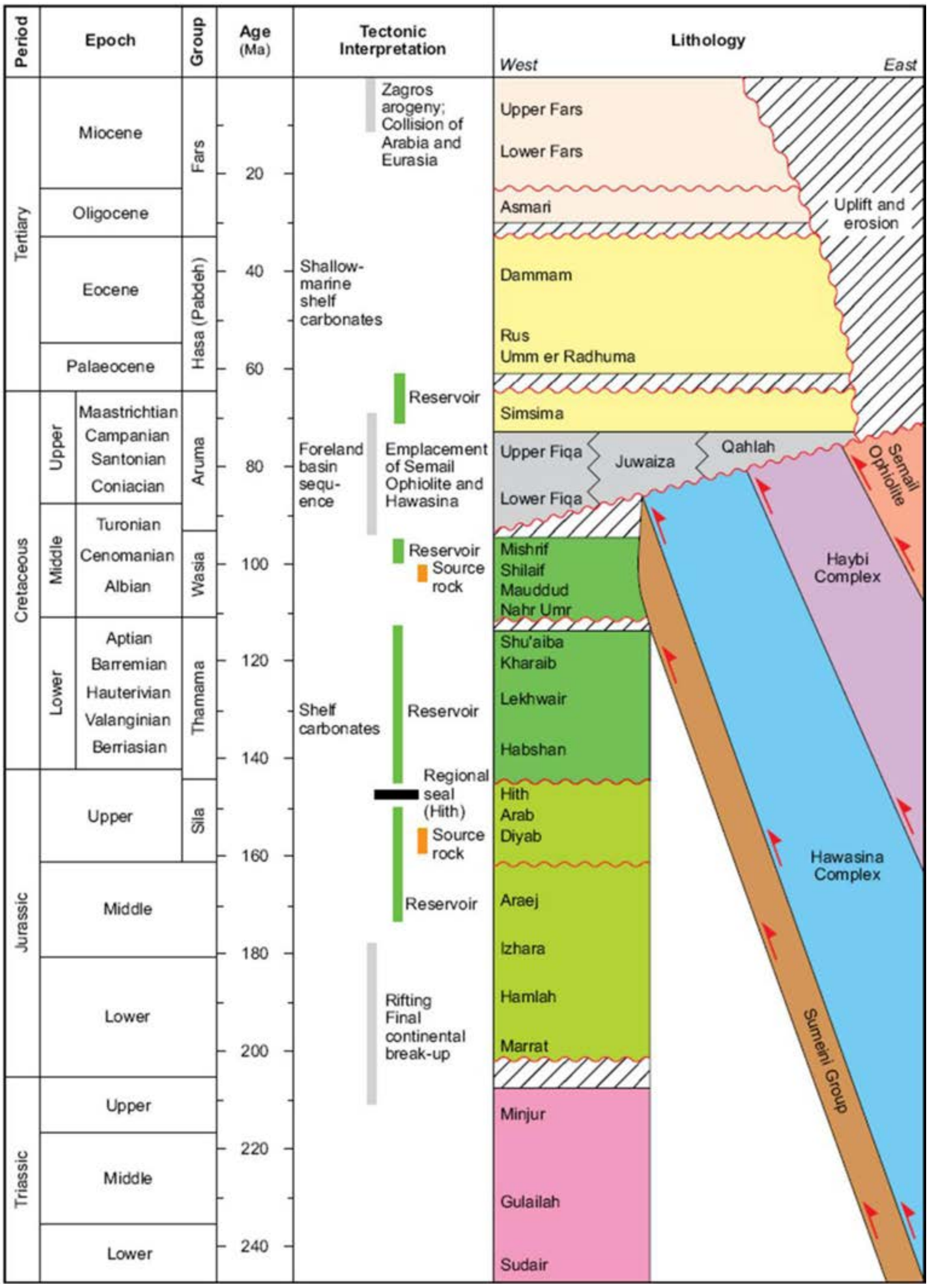
Member D is in general characterised by dense, bioturbated, slightly dolomitised lime mudstones to wackestones with local pelleted packstones. Towards the base of this member is possible to find locally oolitic grainstones.

The Arab Formation can be a prolific reservoir: In Qatar the Arab Formation produces oil and gas at BulHanine, Dukhan, Idd El Shargi (North and South Domes) and Maydan Mahzam, and minor oil at North Field.

In Abu Dhabi the Arab Formation has porosities of up to 30% and permeabilities exceeding 100mD. The Umm Shaif Field holds the largest oil accumulation, with 38° oil. Oil accumulations occur in the Ghasha, Nasr, Bu Tini, Saath Al Raazboot, Abu Al Bukhoosh, Satah, Jarnain, Dalma, Bunduq, Arzana, Hair Dalma, Hail, Umm al Dholou and Belbazem fields.

Figure 46 – Rub Al Khali Basin Stratigraphy

Key features in the Rub Al Khali Basin's stratigraphic history



Source: AkerGeo & SPA data

Lower to Middle Cretaceous

In the Arabian Gulf region, three major Cretaceous depositional cycles are separated by regional unconformities, these are: (i) Lower Cretaceous Thamama Group, which includes Berriasian to middle-late Aptian age rocks; (ii) Middle Cretaceous Wasia Group formed during the late Aptian-latest Cenomanian or earliest Turonian; and (iii) Upper Cretaceous Aruma Group, which includes sediments of Coniacian-Maastrichtian age.

Thamama Group

The Lower Cretaceous Thamama Group accumulated over a time span of about 30mm years during a cycle of extensive flooding of the Arabian Peninsula. During the Early Cretaceous, ramp depositional conditions were established. Later in the Early Cretaceous, an advancing sea pushed clastic sources westward, and a differentiated carbonate shelf was established.

During the Barremian-early Aptian the Thamama Group deposition was differentiated into shallow shelf carbonates and an intrashelf basin within the stable cratonic shelf. Around the margins of this basin, rudist reefs developed that constitute the main Shuaiba Formation reservoir facies.

Shuaiba Formation

Locally in the United Arab Emirates, carbonate build-ups are found on the slopes of the intrashelf basin. In the northern part of the UAE, the carbonate Shuaiba Formation is characterised by wackestone to packstone and a few peloidal grainstones depositional textures. This formation contains also rudist and coral patch reefs or biostromes. The Shuaiba Formation was encountered in some exploration wells, such as the Al-Ali 2 and Bukha 1.

At this location, the formation is characterised by fractured peloidal wackestones that exhibit an extensive recrystallisation of the micrite matrix and the peloidal packstones, which contain echinoderm fragments and shell debris. The porosity of these sediments is filled with calcite spar.

It is widely accepted that much of the oil in the Abu Dhabi Shuaiba reservoirs was generated from the prolific Jurassic Diyab Formation. However, minor potential source rocks are thought to occur as relatively thin kerogen-rich layers.

Wasia Group

During the middle Cretaceous cycle in late Albian-Cenomanian time an intrashelf basin was formed in the southern part of the Arabian Gulf. The basin was filled by deeper water sediments, but along the margins of the basin the carbonate deposition show substantial lateral facies variation with carbonate build-ups occurring in some areas. It has been suggested that that the location of the build-ups was controlled by the same structures over which the present day Mishrif Formation reservoirs are found.

Mauddud Formation

It seems that the Mauddud Formation was deposited in the RAK area under similar conditions as the northern offshore areas of Qatar and Oman. Offshore Qatar, the Mauddud Formation consists of relatively well-developed rudist build-ups, with Orbitolina and echinoderm bearing limestones, but with no significant dolomitisation, porosity and permeability are mainly the result of carbonate dissolution. In Oman, the Mauddud-equivalent strata are oil producing reservoirs from zones with dissolution and dolomitisation porosity that are believed to be associated with subaerial exposure.

Mishrif Formation

In the Cenomanian Mishrif Formation, although rudist build-ups are not as numerous as those of the Shuaiba Formation, significant levels of hydrocarbon production occur in offshore UAE, oil is produced from rudist bank or reef in the Fathe, Southwest Fathe, West Fathe, Falah, Umm Al Dalkh, and Saleh fields. The occurrence of rudists in Saleh field of northern UAE and Malik and Wadi Aswad wells in Oman may indicate that thin rudist build-ups or biostromes may be localised along the crest of prospective structures.

The Mishrif reservoir has primary remnant and leached porosities. In the leached shelfal grainstones to packstones associated with rudist bioherms, porosity can range from 10 to 15%. The leached skeletal grainstones associated with rudist build-ups can have significant porosity and fair permeability depending on grain size of the rudist rubble forming reservoirs. Karstic solution of sub- aerially exposed highs can be also an important factor that can improve the original, primary porosity.

Paleogene

During the Paleogene, the basin that was formed in the Cretaceous and encompassed western Oman, the northern Emirates and Fars in Iran was subsiding. The thick Pabdeh Formation (Paleocene-Oligocene) that was mainly deposited in the Zagros/Lurestan and Ras Al Khaimah troughs consists principally of deep marine shales, marls and limestones. Towards the coastal rims of the basin (including the margins of Ras Al Khaimahh) the Pabdeh Formation merges into a single platform carbonate unit that includes the Jahrum Formation.

Oligocene-Miocene Asmari Formation

Large parts of the northeastern margin of Arabia was sub-aerially exposed and eroded in late Paleogene times. However, sedimentary continuity represented by the Asmari Limestone seems to have been restricted to the Zagros and Ras Al Khaimahh basins.

The massive, dense Asmari limestones with poor primary porosity are important reservoirs in the fields of the Zagros Fold Belt, in this region the Asmari limestone is fractured due to fold deformation and it is the fracture porosity and permeability that makes the Asmari limestone productive.

Rock quality similar to the Zagros can be expected in the Ras Al Khaimah basins and the reservoir potential of the Asmari Formation will be dependent on the development of fractures. As this regions was less affected by fold movements, the reservoir quality of the Asmari limestone can be significantly reduced, however, halokinesis could play a significant role for the development of fractures.

In the Ras Al Khaimah basins, the Asmari Formation is capped by massive salt and the Miocene Gasharan Formation that consists mainly of layers of carbonates containing nodular beds of anhydrite, sandwiched between predominantly anhydritic units with minor limestones, dolomites mudstone and rare siltstone beds.

Source Rocks

Silurian, Jurassic, Mid Cretaceous and Early Tertiary. The most relevant source rocks for the Rub Al Khali, especially in and around Ras Al Khaimah. These are described in greater detail in the following text.

Jurassic

Izhara Formation

The Bajocian (Middle Jurassic) Izhara Formation apparently provides a local source for the Arab formation reservoirs offshore western Abu Dhabi.

Diyab (or Hanifa-Jubailah) Formation

Towards the end of the Middle to early Upper Jurassic major parts of the Arabian platform were inundated and resulted in the development of an intrashelf basin characterised by laminated, bituminous lime mudstones and marls of the Hanifa and equivalent formations which form the prolific source rocks for the oil in most of the Upper Jurassic and Lower Cretaceous reservoirs. For example, in Qatar organic matter in these rocks varies up to 6% (wt) TOC and consists predominantly of sapropelic organic matter.

Cretaceous

Shilaif Formation

The Shilaif Formation is the deeper water, intrashelf basin depositional unit correlative to the shallow water Mishrif Formation. Periodically organic rich (during cycles of low carbonate flux) wackstone and mudstone deposited in low oxygenated conditions constitute source rocks.

Mauddud Formation

The deeper water facies of the Mauddud Formation in the eastern and southeastern parts of Qatar consists of marl and calcareous shale with organic-rich intercalations. The TOC content of these intercalations have been observed up to 8% (wt). It is mainly sapropelic and believed to have excellent source potential.

The existence of a local Mauddud Formation source rock in basinal positions down flank of the Ras Al Khaimah shelf is speculative, Silurian, Jurassic, Mid Cretaceous and Early Tertiary are believed to be the most relevant source rocks for fields in Ras Al Khaimah.

Reservoir Rocks

Butabul Group, Arab-Darb Reservoir Facies

The Arab-Darb reservoir facies have very variable reservoir properties, depending on depositional environment, overburden and diagenetic evolution. In general it can be expected that these reservoirs in the Ras Al Khaimah basin are of lower quality than the Arab reservoirs offshore Qatar and Abu-Dhabi. It is possible that the Arab-Darb was deposited in deeper waters in the Ras Al Khaimah.

The Arab A and B are in general a dolomitic peloidal grainstone, wackestone and packstone with porosities ranging from 5 – 25% and permeability of few mD and seldom exceeding 100mD.

The Arab C is very variable. Can be oolitic, dolomitic grainstone (Qatar) with porosities of 2-25% and permeability of up to 1D or it can be wackestone-boundstone (Abu Dhabi) with porosities of less than 15% and permeability under 10mD.

The Arab D can be in general of better reservoir quality, with reservoir rocks composed of oolitic grainstones and peloidal packstones with porosity up to 30% and permeability of up to 1 D. However, conservatively the reservoir quality of the Arab D can be comparable or slightly better than the Arab A and B.

Thamama Group, Shuaiba Reservoir Facies

All these reservoir facies can have altered porosity-permeability properties. Diagenetic destruction of porosity or development of enhanced secondary porosity-permeability due to diagenetic processes, leaching and fracturing.

Generally, these groups can be broken down further into 3 main subgroups, characterised by depositional environment, namely (i) Shallow Shelf; (ii) Intermediate Shelf; and (iii) Ramp and Slope Deposits.

The shallow facies are predominantly Packstone and grainstones with abundant rudist build ups or are wackestones, demonstrating presence of algal layers and corals build-ups. They generally have porosities of between 15 – 25% and permeability is exceeding 100mD, but rarely more than 1D.

Intermediate shelf facies are predominantly Wackestones, boundstones and packstones with algal colonies, but lime mudstones have been observed in deeper waters. Porosities tend to range between 5 – 18% while observed permeabilities range between 10 – 100mD

Ramp and slope deposits are generally microporous in nature and consist of argillaceous lime mudstones and wackestones. As a result of the microporous structure, these facies often exhibit poor porosity-permeability.

Waisa Group, Mishrif Reservoir Facies:

All these reservoir facies can have altered porosity-permeability properties. Diagenetic destruction of porosity or development of enhanced secondary porosity-permeability due to diagenetic processes, leaching and fracturing.

As with Thamama Group, Shuaiba Reservoir Facies, these groups can be broken down further into 3 main subgroups, characterised by depositional environment, namely (i) Shoal and Shallow Shelf; (ii) Backshoal Platform; and (iii) Platform Margin to Slope Deposits.

Shoal and shallow shelf facies tend to be comprised of bioclastic packstones and grainstones, rudists biostromes. Porosities and permeabilities tend to be high with porosity ranging from 10 – 30%, while permeability varies between 100mD – 1D.

Backshoal platform facies tends to present as coarse to fine packstones, grainstones and wackestones, but also comprised of scattered ophiomorpha and rudists. Porosity ranges between 5 – 20% and permeability ranges between 5 – 100mD.

Platform margin to slope deposits tend to be inter bedded and comprised of prograded, bioturbated medium grained packstones. Porosities range between 3 – 18%, but permeabilities tend to be low, ranging from below 10mD to 50mD.

Waisa Group, Mauddud Reservoir Facies

The producing Mauddud reservoirs in northern Qatar and Oman consist primarily of bioclastic packstone and grainstone with local rudist build-ups and chalky, fractured, limestone. Porosity range from 10 to 30% with permeability typically below 100mD.

Seals

Various possibilities for sealing rocks exist in the Ras Al Khaimah basin. Seals can be intraformational tight limestones, mudstones and evaporites and/or regional seal as listed above. The presence of a regional seal will depend on the location of a prospect and the uplift and erosion history at that particular location.

Main Regional Seals

The Tithonian Hith anhydrite provides effectively regional seals in many of the Middle East large oil fields. The porous Middle and Late Jurassic reservoirs are sealed by the Hith Formation in Saudi Arabia, Bahrain, Qatar and the Emirates.

In the Ras Al Khaimah region the Albian Nahr Umr Formation can be a regional seal for the Thamama (Shuaiba) reservoirs. The Nahr Umr Formation consists of grainstones near the base, overlain by argillaceous packstones and marls. Locally, an Upper Albian shale, the Khatiya formation, is encountered between the Misrif and Mauddud limestones.

The Late Cretaceous foreland basin infill sediments of the Aruma Group can provide seals for the Wasia Group sediments (Misrif Formation). Within the Aruma Group the main sealing units are the Laffan shale, the Fiqa shale and silty marls and the Simsima argillaceous limestone and silty marls. The Oligocene Asmari potential reservoirs are sealed by layers of salt, evaporites and tight limestones of the Gachsaran Formation.

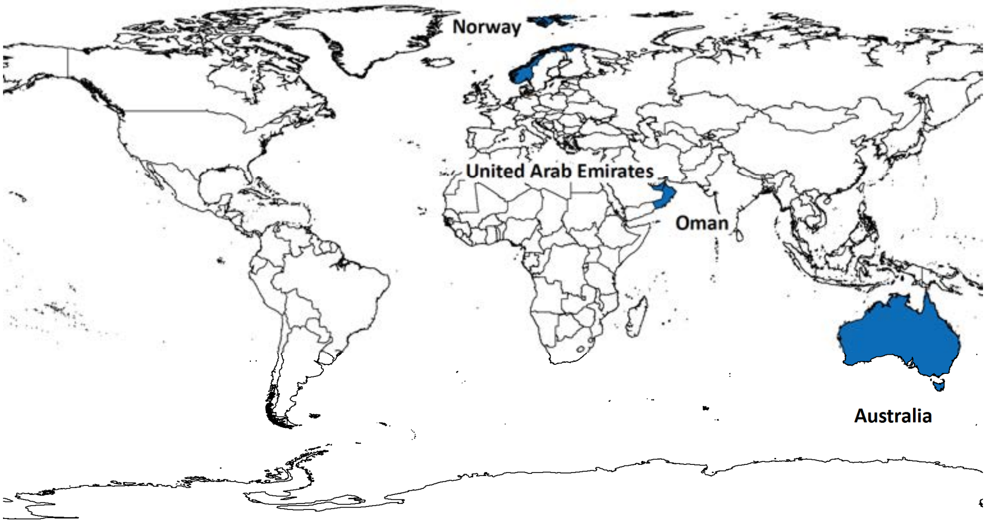
Country Briefs

Hibiscus operates a diverse portfolio across the full exploration/development spectrum. It also enjoys significant diversity in its exposure to geopolitical risk; no one single country dominates its portfolio.

Hibiscus operates in four countries, namely: (i) Australia; (ii) Norway; (iii) Oman; and (iv) United Arab Emirates (Figure 47). It is currently in the final stages of closing the acquisition of a producing asset in the joint development area between Timor-Leste and Australia.

Figure 47 – Countries of Operation

Countries where Hibiscus has interests



Source: ESRI & SPA data

Table 23 – Area of Operation Summary

Country	Summary	Page
Australia	The Australian economy has been buoyed by the demand for resources and energy from Asia and especially China, which has grown rapidly, creating a channel for resources investments and growth in commodity exports. The tax royalty regime has been revised and is becoming increasingly regressive, although more recently a punitive carbon tax has been repealed. Australia remains a high cost operating environment and given that it provinces are gas prone it struggles to attract external investment.	75
Norway	Norway's GDP is heavily reliant on oil and gas revenues, and the high tax environment would ordinarily act as a headwind to foreign direct investment. However, the accelerated capital allowance and 78% cash tax rebate on exploration spending means that a significant proportion of risk capital is met by the Norwegian government, both of which create attractive environment for Oil & Gas investment.	85
Oman	Oman's GDP is almost entirely reliant on oil and gas revenues, with relatively minor amounts being generated by other segments such as tourism and agriculture. As a result, its economy is heavily reliant on oil and gas exports, and hence remains vulnerable to energy price shocks	94
United Arab Emirates	The United Arab Emirates ("UAE") is heavily dependent on Oil & Gas revenues, however, the contribution to revenues from differing sectors such as tourism and trade has been promoted. While Oil & Gas investment has waned modestly, access to the Oil & Gas segment is restricted and tightly controlled. However, the emirates such as Ras Al Khaimah and Sharjah are starting to open up access to more commercially focused Junior E&P companies.	103

Source: SPA data

Australia

The Australian economy has experienced continuous growth and features low unemployment, contained inflation, very low public debt, and a strong and stable financial system. By 2012, Australia had experienced more than 20 years of continued economic growth, averaging 3.5% a year. However, the recent decline in the prices for natural resources raw materials has significantly undermined the outlook for Australia's continued growth. We summarise our Australia section in Table 24.

Table 24 – Section Summary – Australia

Section	Content	Page
Introduction	The Australian economy has been buoyed by the demand for resources and energy from Asia and especially China, which has grown rapidly, creating a channel for resources investments and growth in commodity exports. The high Australian dollar has hurt the manufacturing sector, while the services sector is the largest part of the Australian economy, accounting for about 70% of GDP and 75% of jobs. Australia was comparatively unaffected by the global financial crisis as the banking system has remained strong and inflation is under control.	75
Oil & Gas Segment	While Australia has a limited liquid sector its gas industry is world scale and such is the volume of gas in the north-west shelf that some discoveries have been waiting in line for development for an excess of 40 years waiting for the international gas market to catch up.	77
Fiscal Regime	The tax royalty regime has been revised and is becoming increasingly regressive, although more recently a punitive carbon tax has been repealed. Australia remains a high cost operating environment and given that it provinces are gas prone it struggles to attract external investment.	80

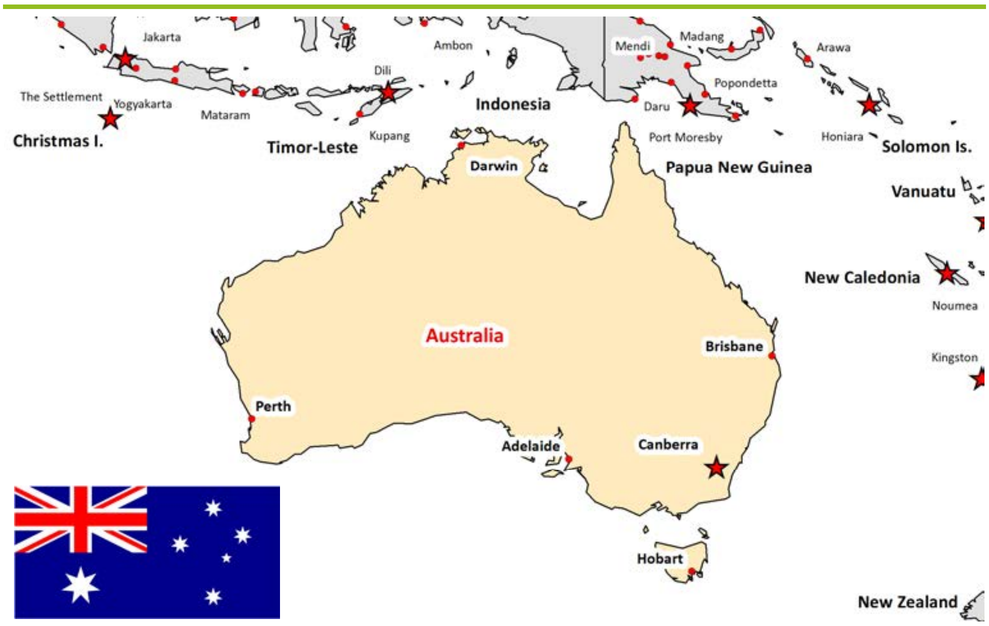
Source: SPA data

Introduction

Australia is a country/continent located between the Indian Ocean and the South Pacific Ocean (Figure 48). The current Prime Minister, Tony Abbott, defeated a motion against his leadership on February 9th at a meeting of his Liberal Party.

Figure 48 – Australia – Map

General Location



Source: ESRI & SPA Data

However, doubts about his leadership remain, but the ruling Liberal-National coalition will want to avoid the sort of in-fighting that crippled the previous, Labour Party government. Low commodity prices and weak consumer spending contribute to our forecast that GDP growth will decelerate slightly, to 2.8%, in 2015, but growth will average 3% annually in 2016-19.

Prehistoric settlers arrived on the continent from Southeast Asia at least 40,000 years before the first Europeans began exploration in the 17th century. No formal territorial claims were made until 1770, when Capt. James Cook took possession of the east coast in the name of Great Britain (all of Australia was claimed as British territory in 1829 with the creation of the colony of Western Australia). Six colonies were created in the late 18th and 19th centuries; they federated and became the Commonwealth of Australia in 1901. The new country took advantage of its natural resources to rapidly develop agricultural and manufacturing industries and to make a major contribution to the Allied effort in World Wars I and II.

In recent decades, Australia has become an internationally competitive, advanced market economy due in large part to economic reforms adopted in the 1980s and its location in one of the fastest growing regions of the world economy.

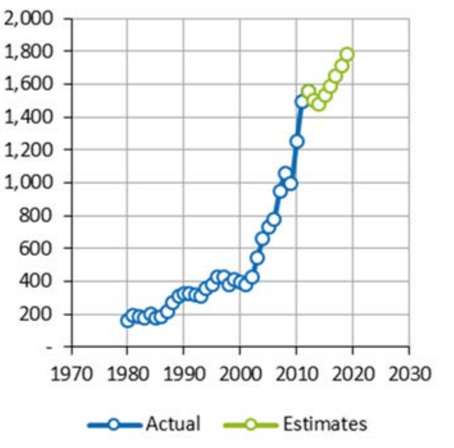
Long-term concerns include aging of the population, pressure on infrastructure, and environmental issues such as floods, droughts, and bushfires. Australia is the driest inhabited continent on earth, making it particularly vulnerable to the challenges of climate change.

Economy

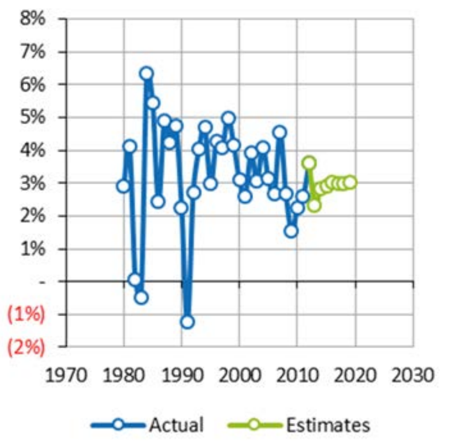
The Australian economy has been buoyed by the demand for resources and energy from Asia and especially China, which has grown rapidly, creating a channel for resources investments and growth in commodity exports. The high Australian dollar has hurt the manufacturing sector, while the services sector is the largest part of the Australian economy, accounting for about 70% of GDP and 75% of jobs. Australia was comparatively unaffected by the global financial crisis as the banking system has remained strong and inflation is under control. With the exception of contraction in its economy, Australia has demonstrated strong and significant GDP growth since 2000. While growth is expected to slow, it is still predicted to remain around the 3% level (Figure 49).

Figure 49 – Australia – GDP

$bn



% Growth



Source: IMF & SPA Data

Oil & Gas Sector

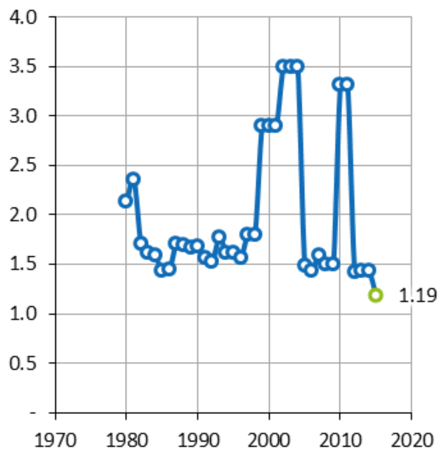
Reserves, Production, Demand & Exports

Oil

As at 2015 Australia had 1.2bn bbl of proved reserves, which is broadly flat year-on-year, but represents a 20% decline over 10 years; the changes in Australia's reserves are shown in Figure 50. While reserves have been flat for the last few years, we believe that the recent decline has been precipitated by the changes to the fiscal terms (discussed from Page 80), have provided a headwind to investment by introducing uncertainty.

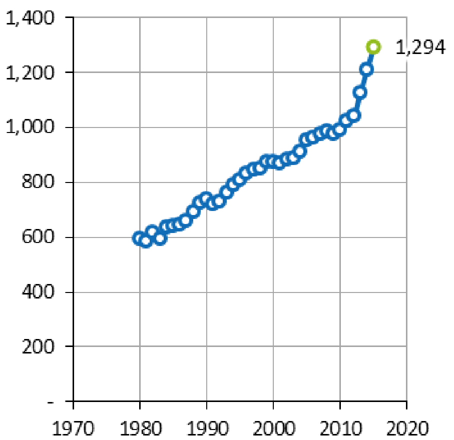
Figure 50 – Australia – Oil Sector Key Data

Reserves (bn bbl)

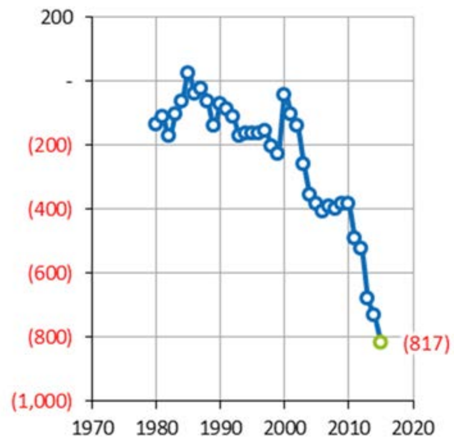


Production (m bpd)

Consumption (m bpd)



Exports (m bpd)



Source: EIA & SPA Data
NOTE: Blue 1980 – 2013
Green 2015 (estimated)

Australia produced 477m bpd in 2014 (Figure 50), an increase of 6.9% from production in 2013, due in principle to the pervasiveness of the high oil price environment. The start of 2015 has seen production plateau somewhat as the oil price and tax changes have conspired to undermine investment.

Australian demand is expected to average 1.3mm bpd in 2015, an increase of 7.5% from 2014 (Figure 50), reflective of the continued growth in the demand for natural resources. However, given the recent hiatus in global growth, we would expect the latest data for 2015, once it becomes available, to show flat or declining consumption. Given this, Australia imported over half of its crude oil needs, which in 2015 is estimated to amount to an estimated 0.82mm bpd (Figure 50).

Gas

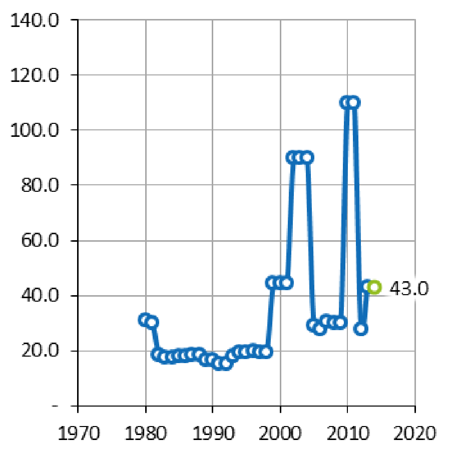
Australia has significant gas reserves, at 43tcf (Figure 51), which represents a significant downgrade. However, this must be interpreted with caution as a significant proportion of this downgrade has very little to do with subsurface and has been precipitated by: (i) the tightening of the application of SPE categorisation (i.e. what constitutes reserves versus contingent resources); and (ii) the treatment of reserves booked to Australia in the joint development area with Timor-Leste.

As can be seen in Figure 51, Australia by comparison to its production has modest demand, which has been in decline since 2010. We think that this has been related, in part at least, to the liberalisation of the Australian gas market. Consequently, exports of remain significant and will continue to be a key feature of the Australian gas market, as given the volume of available resources the Australian market lacks the required depth.

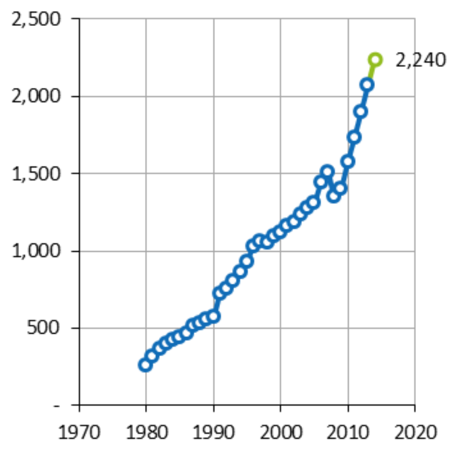
The following figures are estimated for 2014 as country specific asset level data is not yet available.

Figure 51 – Australia – Gas Sector Key Data

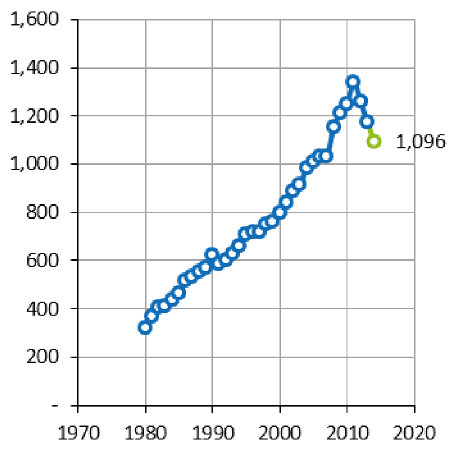
Reserves (tcf)



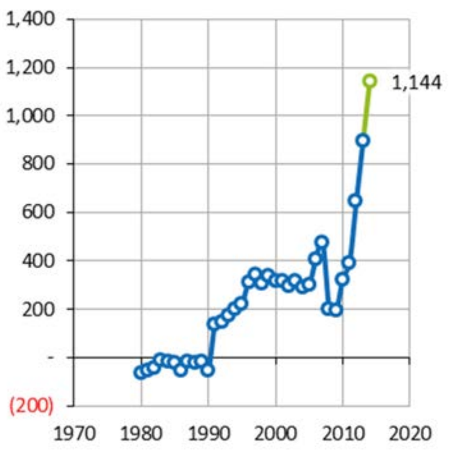
Production (bcf py)



Consumption (bcf py)



Exports (bcf py)



Source: EIA & SPA Data

NOTE:	Blue	1980 – 2013
	Green	2014 (estimated)

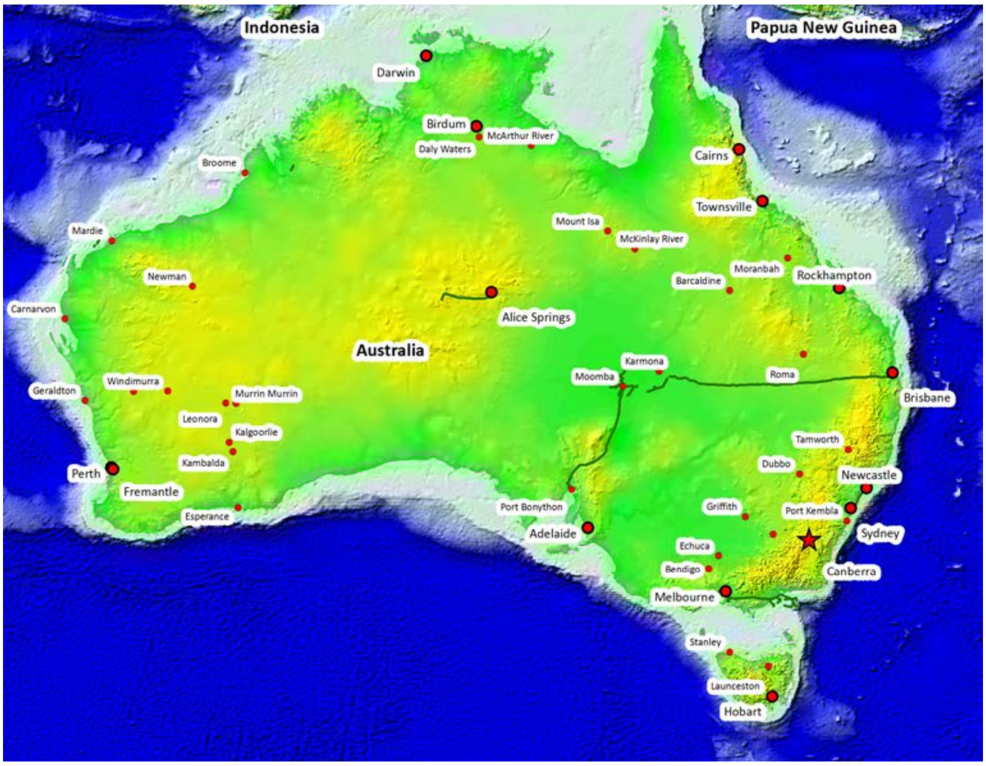
Infrastructure

Oil

Australia has a limited network of oil pipelines (Figure 52), mostly located in the east of the country, and connected to the industrial hubs near Brisbane (Queensland) and Port Bonython (South Australia).

Figure 52 – Australia – Oil Infrastructure

Major Oil Infrastructure in Australia



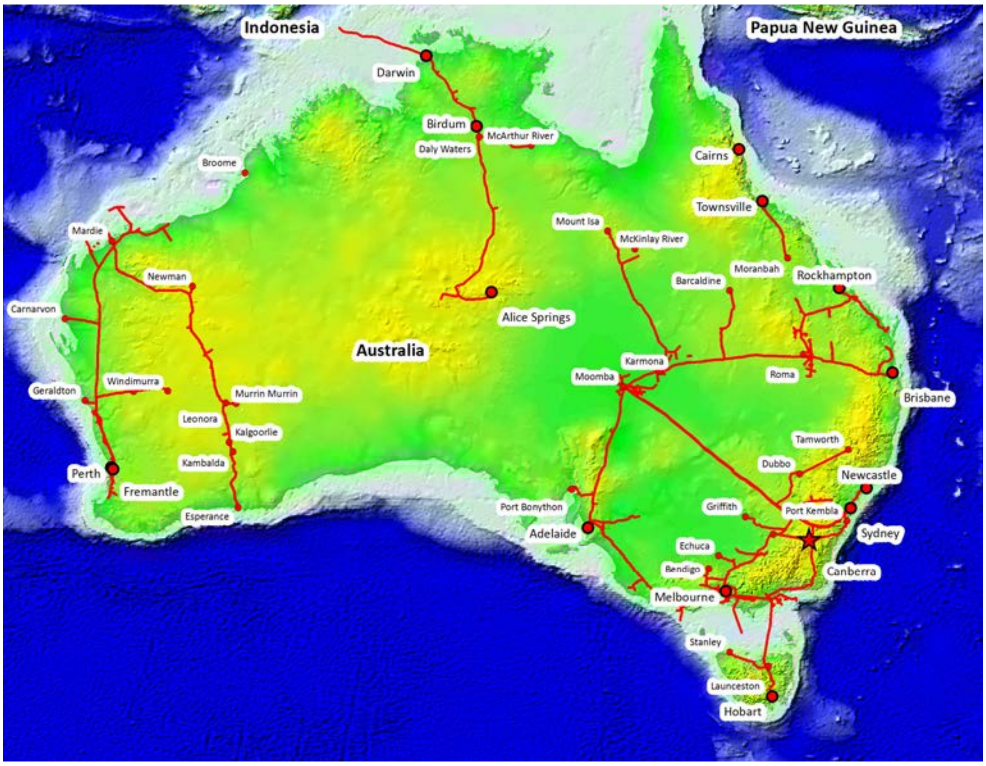
Source: GeoScience Australia, ESRI & SPA data

Gas

Australia operates a limited number of gas pipelines, but the ones that it does operate cover significant distances (Figure 53). With the exception of LNG export facilities, the majority of pipeline infrastructure operates in the south-west of Australia, which is the most densely populated, and therefore the most significant domestic market.

Figure 53 – Australia – Gas Infrastructure

Major Gas Infrastructure in Australia



Source: GeoScience Australia, ESRI & SPA data

Fiscal Regime

Australia operates a concession-based tax royalty system, where a distinction between Federal and State licensing (greater than 3 miles offshore) come under Federal jurisdiction, and onshore/inshore waters come under State control. This results in certain differences in licence and fiscal terms between Federal and State areas, and between States. In summary:

Royalty rates for onshore production vary by State, but royalty does not apply to offshore fields, which are liable to Petroleum Resource Rent Tax ("PRRT"), which is an additional profits tax which applies once fields have achieved a certain rate of return; Australia's principal terms are summarised in Table 25.

Table 25 – Australia – Key Fiscal Terms

Category	Comment
Licence Terms	**Offshore Licences** Offshore Exploration Permits are initially granted for six years. The first three years under the work programme bidding system are mandatory. After this period, providing the current year's work programme has been fulfilled, a permit may be surrendered at any time. At the end of the initial period of tenure, 50% of the area must usually be relinquished, with 50% relinquishment of the remainder after each five-year renewal period. After making a discovery, the permit holder has two years, with an option to apply for a further two to four years, to consider whether to apply for a production licence or a retention lease, depending on the commerciality of the discovery. If the permit holder makes a non-commercial discovery that has a reasonable chance of becoming commercially viable in the next fifteen years, a retention lease may be applied for. A retention lease has a five year duration and may be extended for further five year term. At each renewal, the permit holder must demonstrate the likelihood of the discovery becoming commercial within the following fifteen years. Once the commerciality of a discovery has been established, the licence holder must apply for a production licence. Following amendments to the Petroleum (Submerged Lands) Act 1967 in July 1998, new production licences and third term renewals are now awarded for a term which expires five years after the cessation of production. **Onshore/Inland Waters Licences** The terms and relinquishment requirements for onshore licences varies by State:

State	Allocation	Maximum Permit Size	Relinquishment	Initial Term (Renewal Term)
New South Wales	Open application	10,000 km2	25% on each renewal	6 years (up to 6 years)
Northern territory	Open application	200 graticular blocks (5*5 mins)	50% on each renewal	2-5 years (2-5 years)
Queensland	Relinquished areas advertised	No maximum	25% at end of years 2 & 3	4 years (up to 4 years)
South Australia	Prospective regions gazetted, otherwise open	10,000 km2	25-50% on each renewal	5 years (5 years)
Tasmania	Open application	No maximum	100% after 5 years	5 years (5 years)
Victoria	Areas offered are bid upon	12,500 km2	One renewal only – 50% on renewal	5 years (5 years)
Western Australia	Areas offered are bid upon	400 graticular blocks (5*5 mins)	50% on each renewal	6 years (5 years)

Category	Comment
Equity Participation	None
Bonuses, Rentals and Fees Signature Bonuses Payable	Area rentals and various small fees are payable.
Royalty	Does not apply to offshore fields taxed under the PRRT system. In general, royalties are calculated as a fixed percentage of the 'wellhead value' of petroleum (usually between 10% and 12.5% with deduction for transportation costs). The definitions of allowable costs vary between Federal/State and from State to State.
Corporate Income Tax Income	FIT is levied at 30% of gross income less allowable deductions, including royalty/resource rent/excise payments. Contractor can normally choose between a straight line depreciation or a double declining balance method based on 'useful life of asset'. Wood Mackenzie assumes double declining balance over 15 years for tangible onshore investments, and 20 years for offshore investments. Losses are normally carry forward for 7 years.
Additional Profits Tax	Petroleum Resource Rent Tax ("PRRT") is a secondary tax on offshore petroleum production, in lieu of royalty, and is calculated on a pre-tax profit basis at a rate of 40%. Where deductions exceed revenues in any year then the excess is compounded forward at a rate known as the threshold rate, set at the Commonwealth long-term bond rate plus 5 or 15%, for development and exploration costs, respectively.

Category	Comment
Other Taxes	10% Goods and Services Tax on goods and services consumed can be reclaimed through input tax credits. All exported goods and services are exempt from GST, however input GST can still be reclaimed even if it is not added to the sales price of the final product. Import duties are levied at 5% for certain types of goods.
Excise Duty	Depending on production level and the age of production, excise duties of 0-55% are payable for oil and condensate produced. Excise duty is levied on the FoB sales price received by a field once 30mmbbl has been produced. Excise duty is not applicable to offshore projects taxed under the PRRT regime.
Ring Fencing	At field level for PRRT, although exploration costs can be consolidated at the Company level. At field level for royalty and excise duty, if applicable. At company level for income tax.
Product Pricing	Realised prices. Transportation costs for gas can often be very considerable in Australia.

Source: WoodMackenzie & SPA data

Operating in Australia

Standard and Poor's ("S&P's") rates Australia's sovereign debt as AAA and its currency as AAA; a guide to S&P's ratings is provided in the *Appendix* (*Country Brief* – Page 130); the EIU's Country Risk Summary is provided in Table 25. As a guide, however, the Heritage Foundation's annual Index of Economic Freedom provides a good benchmark with which to start.

Table 26 – Australia – Country Risk Summary

Category	Ranking	Comment
Sovereign Risk	BBB	The public finances are less fragile than those of most other developed countries, but the government nevertheless plans to increase taxes and cut spending in fiscal year 2014/15 (July-June). The Economist Intelligence Unit believes that the government will make gradual progress in reducing the budget deficit in 2015-16.
Currency Risk	BBB	After being above parity with the US dollar in 2011 and 2012, the Australian dollar has since depreciated by around 10%, putting the real effective exchange rate on a par with that in 2010. Further modest depreciation is likely, but will be limited in size by high domestic interest rates compared with those in the US.
Banking Sector Risk	A	Banking sector regulatory standards have recently been tightened and macro--economic fundamentals are improving. Moreover, the sector will not have to make major adjustments to comply with Basel III international capital-adequacy rules.
Political Risk	AA	The government has a clear majority in the lower house of parliament. However, the passing of legislation is likely to be slow in some policy areas, as the ruling coalition lacks a majority in the upper house and is struggling to build reliable working relationships with minor parties and independents.
Economic Structure Risk	BB	The economic structure risk is on a moderating trend, driven by changes in macroeconomic fundamentals, particularly a structural decline in the current-account deficit and a relatively steady public debt-to-GDP ratio.

Source: EIU & SPA data

In September 2013, Liberal Party leader Tony Abbott was elected prime minister following his coalition's victory in national elections. Australia is one of the Asia–Pacific's wealthiest nations and has enjoyed more than two decades of economic expansion.

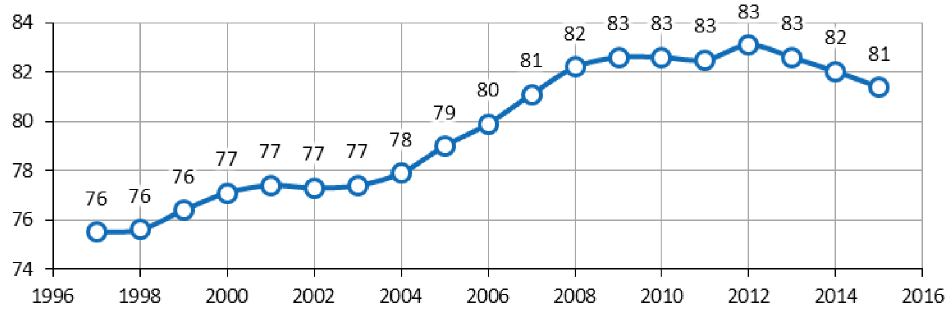
Australia emerged from the global recession relatively unscathed, but stimulus spending by the previous Labour government generated a fiscal deficit. Australia is internationally competitive in services, technologies, and high-value-added manufactured goods. Mining and agriculture are important sources of exports.

Australia’s strong commitment to economic freedom has resulted in a policy framework that has facilitated economic dynamism and resilience. Although overall economic freedom has declined slightly over the past five years, the Australian economy performs remarkably well in many of the 10 economic freedoms. Regulatory efficiency remains firmly institutionalized, and well-established open-market policies sustain flexibility, competitiveness, and large flows of trade and investment. In 2014, Australia became the first developed country to repeal a carbon-emissions tax.

Banking regulations are sensible, and lending practices have been relatively prudent. Monetary stability is well maintained, with inflationary pressures under control. A well-functioning independent judiciary ensures strong protection of property rights, and corruption has been minimal. Australia’s Heritage Index score is illustrated in Figure 54.

Figure 54 – Australia – Heritage Index Score

Economic Freedom Score



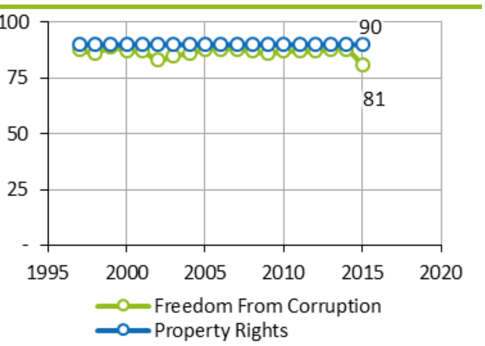
Category	**Chart**

Rule of Law

Australia has a stable political environment with well-established and transparent political processes, a strong legal system, and a professional bureaucracy. Anti-corruption measures are generally effective in discouraging bribery of public officials.

Australia's judicial system operates independently and impartially. Property rights are secure, and enforcement of contracts is reliable.

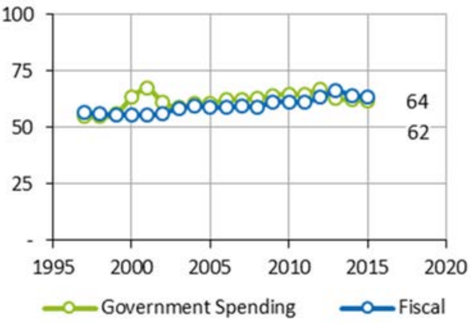
Expropriation is highly unusual.



Limited Government

The top individual income tax rate is 45%, and the top corporate tax rate is 30%. Other taxes include a value-added tax and a capital gains tax.

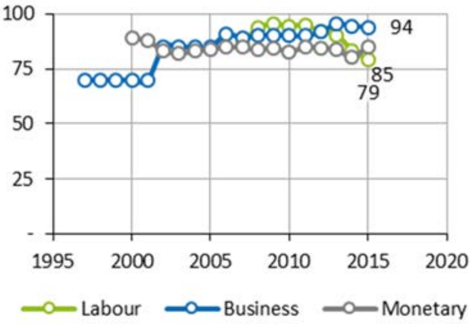
Total tax revenues equal about 27% of the domestic economy. A controversial carbon tax has been repealed. Government expenditures equal 35.7% of the economy, and public debt is equivalent to less than 30% of GDP.



Regulatory Efficiency

Start-up companies enjoy great flexibility under licensing and other regulatory frameworks. It takes only one procedure to start a business, and no minimum capital is required.

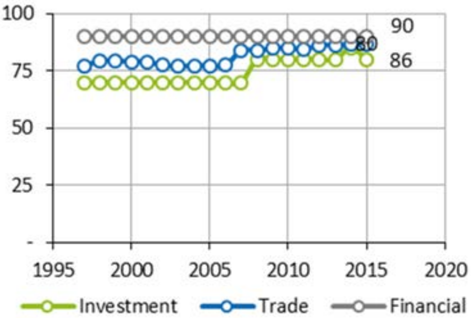
Flexible labour regulations facilitate a dynamic labour market, increasing overall productivity. In 2014, the government lifted price controls on electricity to encourage market-based production of power.



Open Markets

Australia has a 1.8% average tariff rate, and non-tariff barriers are low. Large-scale foreign investments are subject to review. In 2013, the government rejected a takeover of Australia's GrainCorp by the U.S. firm Archer Daniels Midland.

The well-developed financial sector offers a wide range of financing instruments. The banking system has remained stable, and all banks are privately owned.



Source: Heritage Index of Economic Freedom & SPA data

Note: For details on each of the sectors, see *Heritage Foundation's Measurement of Economic Freedom* (Page 131)

Norway

Norway's GDP is heavily reliant on oil and gas revenues, and the high tax environment would ordinarily act as a headwind to foreign direct investment. However, the accelerated capital allowance and 78% cash tax rebate on exploration spending means that a significant proportion of risk capital is met by the Norwegian government, both of which create attractive environment for Oil & Gas investment. We summarise our Norway section in Table 27.

Table 27 – Norway – Section Summary

Section	Content	Page
Introduction	Norway is a mature democracy with an open economy providing access to international firms. The recent election of a socialist government is likely to result in the continuation of the relatively high taxation environment.	85
Oil & Gas Segment	Norway is an important supplier of relatively light sweet crude to the international market. It has a well-developed infrastructure and provides open access to its licence areas to those that demonstrate technical and financial capability.	87
Fiscal Regime	Norway uses a tax royalty scheme to access the economic benefits from oil production. Where the concession fiscal regime is still in place, and royalties were once payable, the royalties have been abolished. Corporate income tax (28%) and an additional profits tax (Special Tax, at 50%) are both payable and not deductible against each other; hence, the total marginal tax rate payable is 78%. Nevertheless, the tax rebate of 78% of exploration investment makes Norway an attractive destination for Oil & Gas investment.	91

Source: SPA data

Introduction

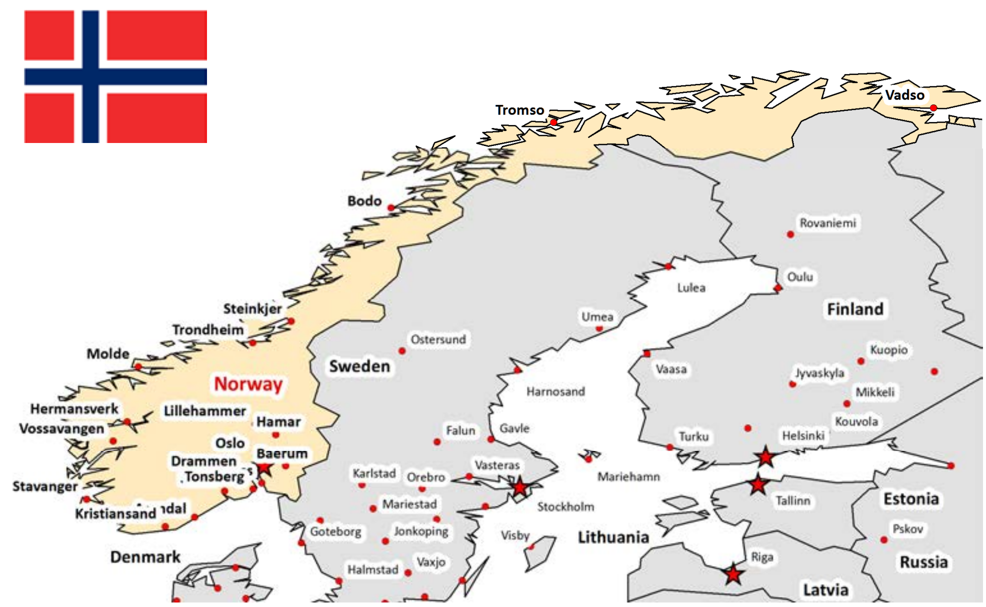
Norway is located in Northern Europe, bordering the North Sea and the North Atlantic Ocean, west of Sweden (Figure 48). The country is a Constitutional Monarchy, led by King Harald V, whose government is led by Prime Minister Erna Solberg of the Conservative Party.

Norway has been a member of NATO since 1949, but voters have twice rejected membership in the European Union ("EU"). Instead, it maintains close economic interaction with EU members under the European Economic Area agreement.

The country has significant resources available to it, but is highly dependent on the petroleum sector, which accounts for the largest portion of export revenue and about 20% of government revenue. Norway is the world's third-largest natural gas exporter; and seventh largest oil exporter, making one of its largest offshore oil finds in 2011.

Figure 55 – Norway – Map

General Location



Source: ESRI & SPA Data

Economy

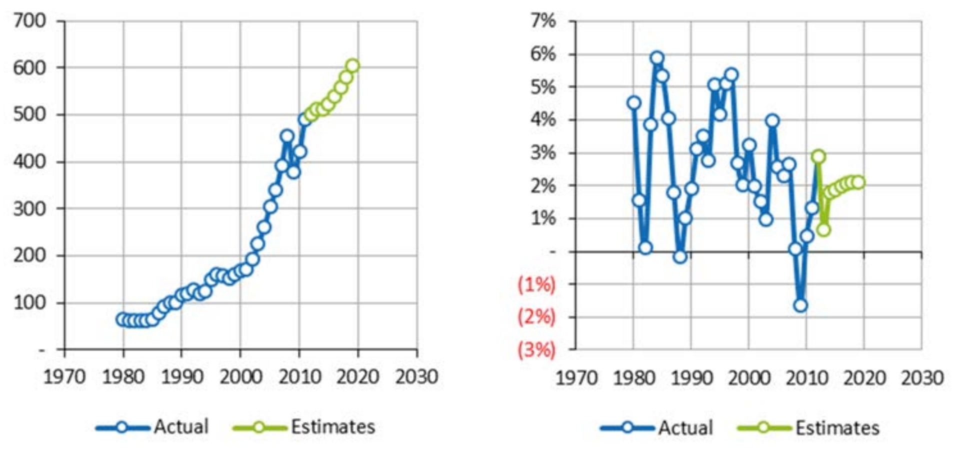
The Norwegian economy is a prosperous mixed economy, with a vibrant private sector, a large state sector, and an extensive social safety net. The government controls key areas, such as the vital petroleum sector, through extensive regulation and large-scale state-majority-owned enterprises.

Norway opted to stay out of the EU during a referendum in November 1994; nonetheless, as a member of the European Economic Area, it contributes sizably to the EU budget. In anticipation of eventual declines in oil and gas production, Norway saves state revenue from the petroleum sector in the world's second largest sovereign wealth fund, valued at over $830bn in January 2014 and uses the fund's return to help finance public expenses.

After solid GDP growth in 2004 – 2007, the economy slowed in 2008, and contracted in 2009, before returning to positive growth in 2010 – 2012 (Figure 56), however, the government budget is set to remain in surplus.

Figure 56 – Norway – GDP

$bn **% Growth**



Source: IMF & SPA Data

Oil & Gas Sector

Reserves, Production, Demand & Exports

Oil

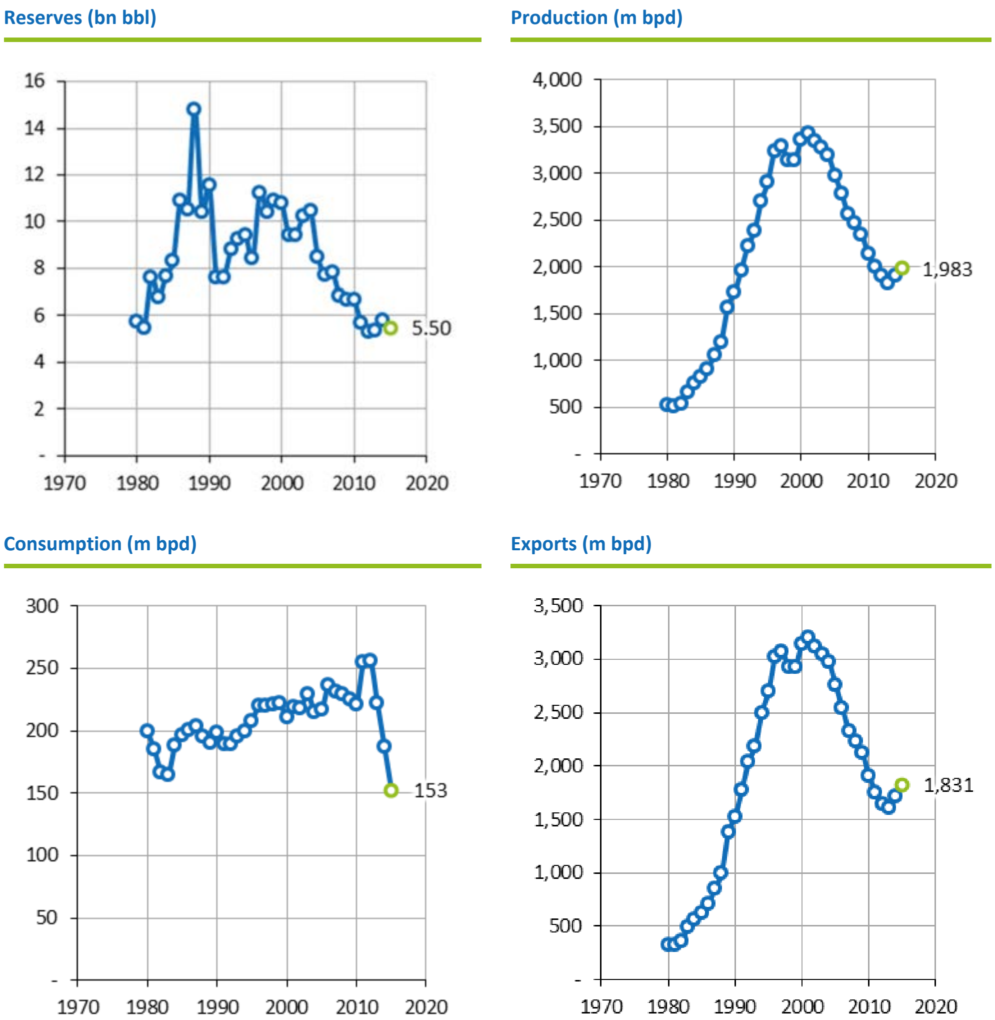
At the start of 2015 Norway had 5.5bn bbl of proved reserves, which we estimate will represent a decline of ~6% over 2014; the changes in Norway's reserves are shown in Figure 57. While reserves have been flat for the last few years, we believe that the changes to the fiscal terms (discussed from Page 80), have provided significant impetus to exploration in the region, and the small uptick in 2013 we believe is the reversal of the general downward trend.

Norway is estimated to have produced 2.0mm bpd in 2015 (Figure 57), an increase of ~4.2% over 2014, which the NPD attribute to the greater availability of infrastructure and new production. Norway's production accounted for 2.1% of the global total.

The uptick in production seen at the start of 2014 is expected to have continued in to 2015 which marks the reversal what has been a general decline in production rates; production is expected to rise ~4% year on year. Norwegian demand is expected to average 153mm bbl in 2015, a continuing the decline observed in 2013 to 2014 (Figure 57). Demand remained largely static at ~0.25mm bpd, modest increase of 0.5% over 2012.

Norway is estimate to export ~1.8mm bpd in 2015, which accounted for in excess of 90% of its production (Figure 57). Norway's principle export partner is the United Kingdom, accounted for >50% of its exports 2014.

Figure 57 – Norway – Oil Sector Key Data



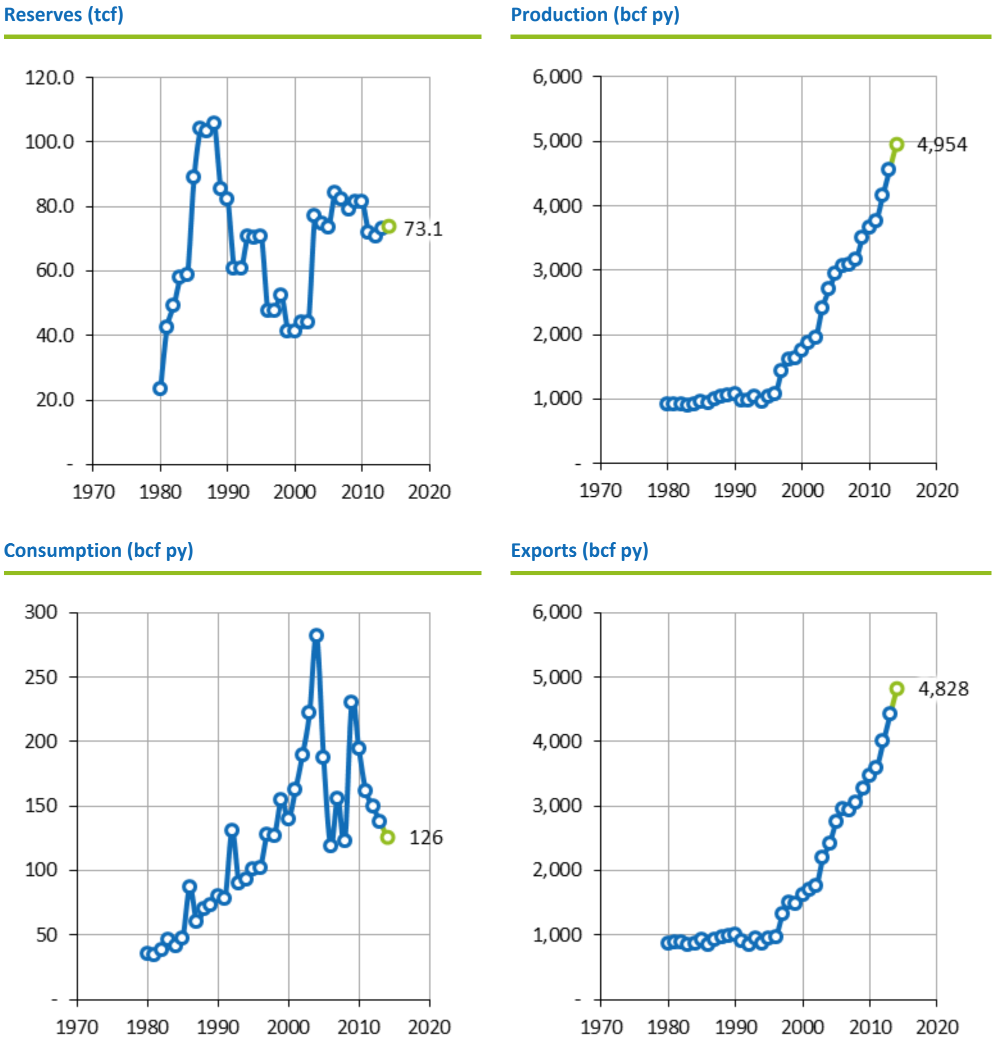
Source: EIA & SPA Data

NOTE:	Blue	1980 – 2013
	Green	2015 (estimated)

Gas

Norway's gas reserves grew 3.1% to 73.1tcf in 2014 (versus 2013) despite production rising to ~4.9tcf py (Figure 58). Given that demand declined, this increase in production was exported (Figure 58).

Figure 58 – Norway – Gas Sector Key Data



Source: EIA & SPA Data

Note:	Blue	1980 – 2013
	Green	2014 (estimated)

Infrastructure

Oil

Norway has an extensive network of subsea oil pipelines (Figure 59), including 8 major domestic oil pipelines with a total capacity of more than 2.2mm bpd which connects offshore oilfields with onshore processing terminals. There are numerous smaller pipelines that connect North Sea fields to either the Oseberg Transport System or the Troll I and II pipeline systems, with the remaining offshore production brought ashore via shuttle tanker.

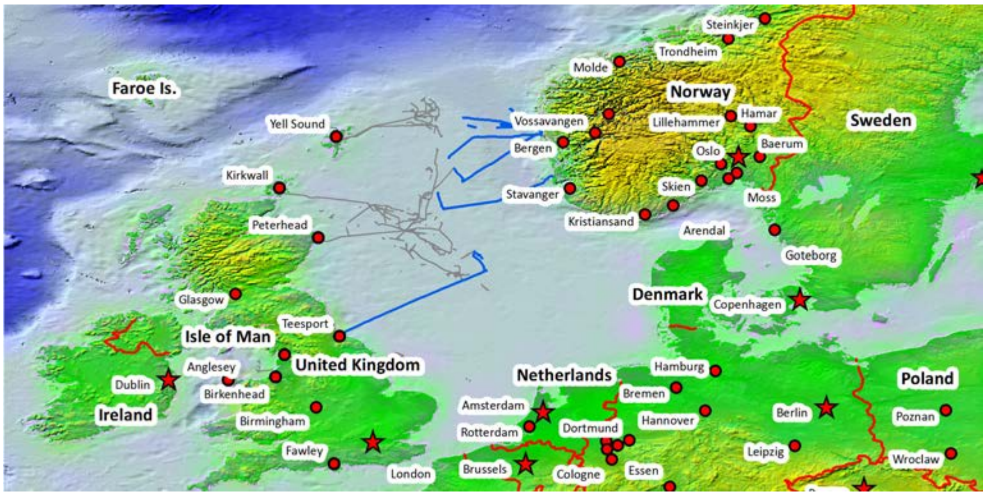
ConocoPhillips operates the 900m bpd subsea Norpipe, which connects Norwegian oil fields in the Ekofisk system, as well as associated fields in both Norwegian and UK waters, to the oil terminal and refinery at Teesside, England. The pipeline is a 50-50 joint venture between ConocoPhillips and Statoil.

Gas

Norway operates a number of gas pipelines (Figure 60) which connect directly with other European countries, specifically France, the United Kingdom, Belgium, and Germany. Franpipe (42” diameter), with a capacity of 692bcf py, exports gas to Dunkirk, France, while Zeepipe I, IIA and IIB (each with a diameter of 40” combined capacity of capacity 2.4tcf py) exports gas to Zeebrugge, Belgium.

Figure 59 – Norway – Oil Infrastructure

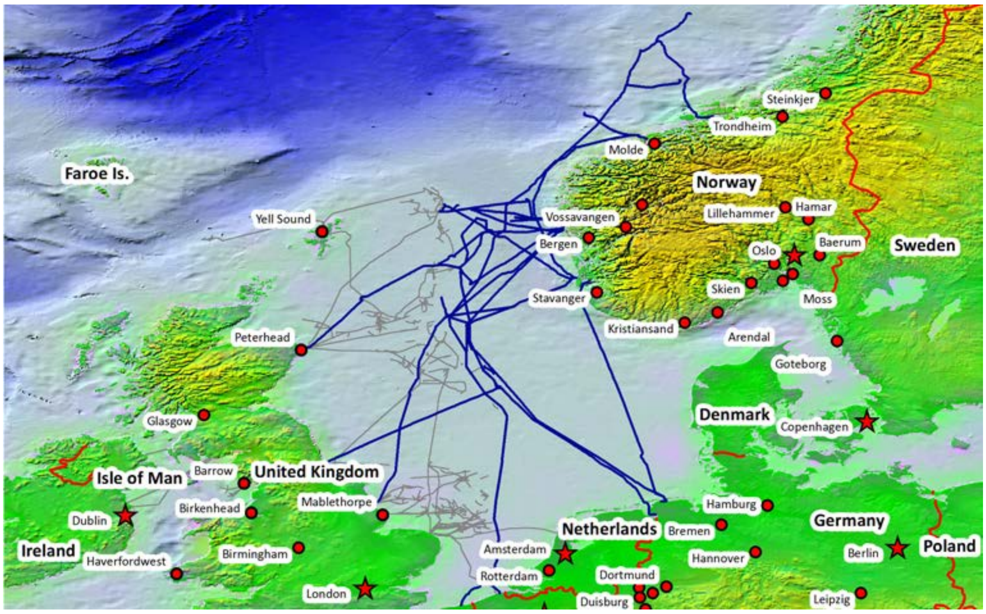
Major Oil Infrastructure in Norway



Source: DECC, NPD, ESRI & SPA data
NOTE: Gray denotes privately own liquids infrastructure

Figure 60 – Norway – Gas Infrastructure

Major Gas Infrastructure in Norway



Source: DECC, NPD, ESRI & SPA data
NOTE: Gray denotes privately own liquids infrastructure

Europipe I (40”) and II (42”) (combined capacity of 1.4tcf py), exports to Dornum, Germany, while Norpipe (36” – 572bcf py), runs to Emden, Germany. Vesterled (32” – 463bcf py), links to St. Fergus, Scotland, while Langeled (North – 42” & South – 44” – 893bcf py), links to Easington on the east coast of England. All of Norway’s export lines are operated by Gassco, with some pipelines exporting straight from the production platform, while others are exported via gas facilities.

Fiscal Regime

Norway uses a tax royalty scheme to access the economic benefits from oil production. Where the concession fiscal regime is still in place, and royalties were payable, the royalties have been abolished. Corporate income tax (28%) and an additional profits tax (Special Tax, at 50%) are both payable and not deductible against each other; hence, the total marginal tax rate payable is 78%; Norway's principal terms are summarised in Table 28.

Table 28 – Norway – Key Fiscal Terms

Category	Comment
Licence Terms	Non-exclusive exploration licence 3 years Exclusive exploration licence period 3-6 years + a possibility of a 4 year extension Production licence 15 years
Equity Participation	The State reserves the right to take direct participation, at varying rates, through state entity Petoro, which manages the State's Direct Financial Interest ("SDFI") Average SDFI interest ~20% (where is has elected to participate), paying its full share of costs from day one The State also has a major, indirect participation through its majority ownership of Statoil, the NOC. Statoil has no mandatory right to participate in licences Valuations only provide for Hibiscus's net interest
Bonuses, Rentals and Fees Signature Bonuses Payable	No signature or production bonuses are payable Annual rentals are NOK4,000 ($667) per km^2 in the exploration phase, increasing annually during the production phase to a maximum of NKr121,500 (UMYR20,250) per km^2 SPA has not specifically allowed for any rental payments
Royalty	None payable for fields approved after 1 January 1986 Royalty was previously payable on older fields but has now been abolished
PSC Cost Recovery	-
PSC Profit Sharing	-
Corporate Income Tax Income	Corporation Tax ("CIT") is levied at 28% of revenue less operating costs and depreciation. Offshore production assets depreciated straight line over 6 years, measured from date of purchase. Leased assets may be capitalised according to a deemed purchase price. Exploration costs can either be expensed or capitalised without uplift Tax value of exploration losses are reimbursable in the tax year that expenses are incurred, even if the explorer has no taxable income that year. Losses are carried forward with interest at after-tax risk free rate
Additional Profits Tax	Levied at 50% of taxable income for CIT purposes, with an additional 30% uplift on capital expenditure over 4 years (i.e. 7.5% p.a.) CIT is not deductible for Special Tax and vice versa.
Other Taxes	Minor CO_2 and NO_x levies are payable on gas flared, gas or oil/condensate used for power generation and nitrous oxide emissions This has not been considered in the valuations
Ring Fencing	Companies can consolidate their upstream activities for income tax and special tax purposes Onshore losses may not be set against offshore income.
Product Pricing	Norm prices are used to calculate revenue for tax purposes, which are fixed by government taking account of market conditions and reference transactions.

Source: WoodMackenzie & SPA data

Operating in Norway

This is difficult to gauge accurately as it is subjective and dependent on each persons' perspective. Standard and Poor's ("S&P's") rates Norway's sovereign debt as AAA and its currency as AAA; a guide to S&P's ratings is provided in the *Appendix* (*Country Brief* – Page 130). As a guide, however, the Heritage Foundation's annual Index of Economic Freedom provides a good benchmark with which to start.

The 2013 general election saw the four centre-right parties win 96 out of 169 seats, but the centre-left Labour Party remains the largest in parliament. The Conservatives and the Progress Party formed a minority right-of-centre coalition government, after protracted negotiations.

The strong competitiveness of the Norwegian economy is built on openness and transparency, with policies that support dynamic trade and investment, and the legal framework is among the world's strongest, providing effective protection of property rights.

As such, the rule of law is well maintained, and a strong tradition of minimum tolerance for corruption continues. Norway is considered to be relatively low risk, with an overall rating of "AA"; S&P rates its sovereign debt as "AAA." The EIU's summary of the key criteria is provided in Table 29.

Table 29 – Norway – Country Risk Summary

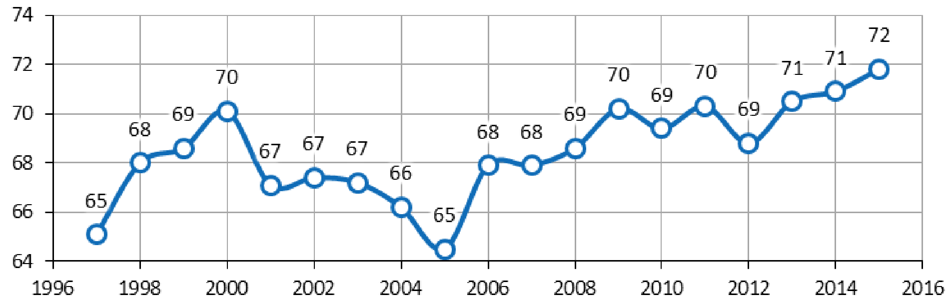
Category	Ranking	Comment
Sovereign Risk	AAA	The stock of public debt is comparatively modest, at around 30% of GDP, and is more than offset by Norway's large sovereign wealth fund, in which it invests petroleum earnings. However, we expect this to rise to 39.1% by 2016, driven by a large increase in expenditure as automatic stabilisers come into effect and the government tries to combat the impact of lower oil prices.
Currency Risk	AA	The krone can be volatile, fluctuating according to oil prices and risk appetite. Highlighting this issue is the recent depreciation triggered by a large fall in the price of oil. No further significant movements are anticipated and the depreciation may help areas of the economy unrelated to oil.
Banking Sector Risk	AA	Direct exposure to distressed sovereign debt is low, but banks' shipping and commercial property exposures are sensitive to global growth. Household debt and house prices, fuelled by low interest rates, also give some cause for concern. However, risks are mitigated by low unemployment and high savings.
Political Risk	AAA	Risks to political stability are limited, hence Norway's triple-A rating in this category. Norway's tradition of well-functioning minority administrations and broad political consensus among the country's main parties will continue to underpin political stability.
Economic Structure Risk	AA	The impact of the petroleum sector on the exchange rate makes the non-hydrocarbon economy less competitive, although this is mitigated by keeping much of the petroleum revenue in offshore investments.

Source: EIU & SPA data

Norway's economic freedom score is 71.8, making its economy the 27th freest in the 2015 Index. Its score has increased by 0.9 point since last year, with improvements in investment freedom, the management of government spending, and monetary freedom partially offset by declines in freedom from corruption and business freedom. Norway is ranked 15th out of 43 countries in the Europe region, and its overall score is well above the world and regional averages. Norway's economic score is summarised in Figure 61.

Figure 61 – Norway – Heritage Index Score

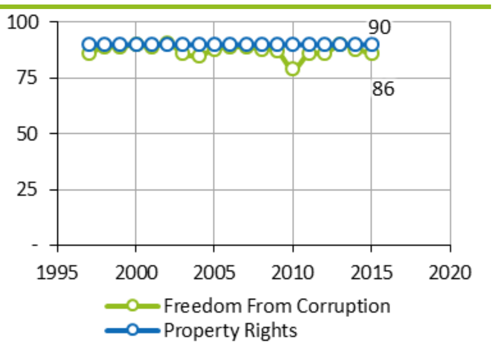
Economic Freedom Score



Category	**Chart**

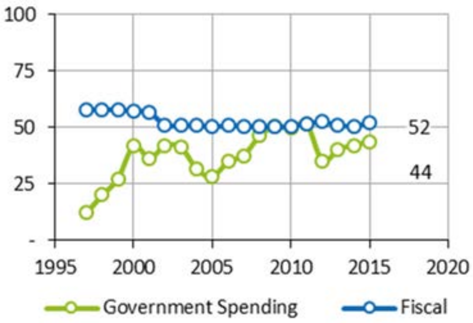
Rule of Law

Norway remains one of the world's least corrupt countries. Well-established anti-corruption measures reinforce a cultural emphasis on government integrity. Transparency is a key institutional asset. The judiciary is independent, and the court system, headed by the Supreme Court, operates fairly at the local and national levels. Private property rights are securely protected, and commercial contracts are reliably enforced.



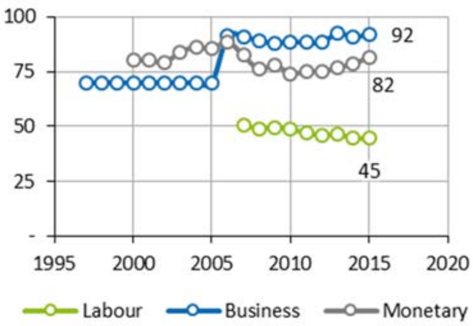
Limited Government

The top individual income tax rate is 47.8%, and the top corporate tax rate is 28%. Other taxes include a value-added tax ("VAT"), a tax on net wealth, and environmental taxes. The overall tax burden equals 43.2% of gross domestic income. Government spending equals 44% of GDP, and public debt equals 34% of the domestic economy. Public finances are partially funded by a $750 billion sovereign wealth fund.



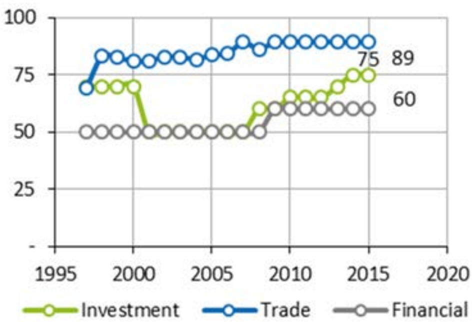
Regulatory Efficiency

The overall regulatory framework is transparent and competitive. Launching a business is subject to minimum capital requirements but takes only five procedures. Bankruptcy procedures are modern and efficient. Labour regulations are relatively rigid, and the non-salary cost of employing a worker is high. Monetary stability has been well maintained, although the government subsidises numerous renewable energy projects.



Open Markets

Norway has a low 0.5% average tariff rate. There are few government barriers to international trade and investment, but investment in some sectors may be screened. The financial sector is market-driven, although the state retains ownership of the largest financial institution. Supervision of the banking sector is prudent, and regulations are largely consistent with international norms. Credit is allocated on market terms.



Source: Heritage Index of Economic Freedom & SPA data
Note: For details on each of the sectors, see *Heritage Foundation's Measurement of Economic Freedom* (Page 131)

Oman

Oman's GDP is almost entirely reliant on oil and gas revenues, with relatively minor amounts being generated by other segments such as tourism and agriculture. As a result, its economy is heavily reliant on oil and gas exports, and hence remains vulnerable to energy price shocks; the sections are summarised in Table 30.

Table 30 – Oman – Section Summary

Section	Content	Page
Introduction	Oman has always benefited from its position in the Strait of Hormuz, with trade having featured heavily in its past. Further information about Oman's economy can be found in the *Appendix* (*Country Brief Supplement* – Page 130).	94
Oil & Gas Segment	Oil and gas is an important contributor to Oman's GDP, and as a result it's infrastructure and economy provides ample support for investment in the segment.	96
Fiscal Regime	Oman operates under PSC terms, with contracts negotiated with direct contact with the Ministry of Oil and Gas. Profit oil splits may be fixed, or on a sliding scale based upon production rates. Corporate income tax is paid on the contractors' behalf by the government.	100

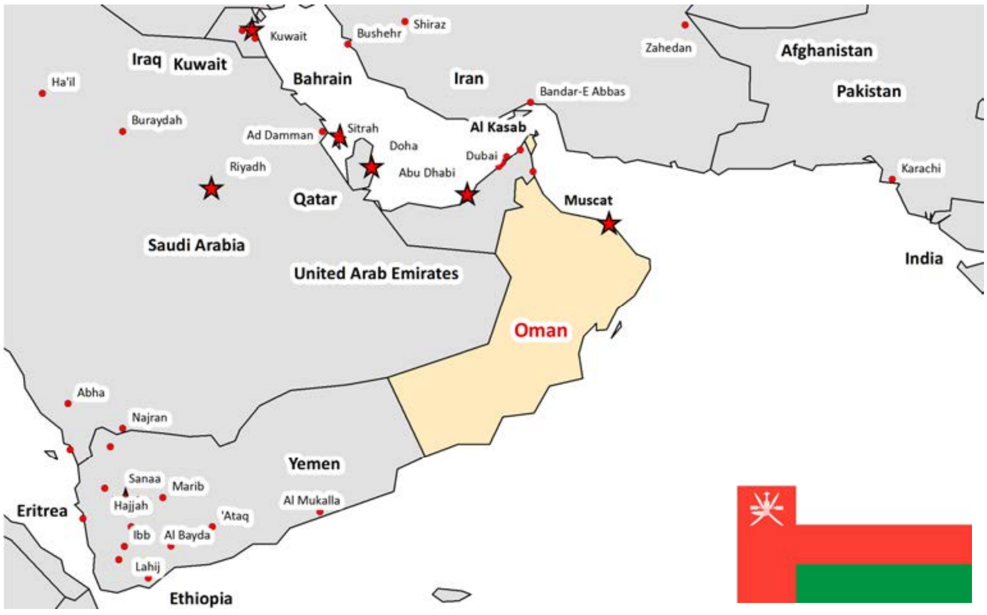
Source: SPA data

Introduction

Oman is located in the Middle East, bordering the Arabian Sea, Gulf of Oman, and Persian Gulf, between Yemen and UAE (Figure 62). The inhabitants of the area of Oman have traditionally been traders, profiting from the Indian Ocean trade routes.

Figure 62 – Oman – Map

General Location



Source: ESRI & SPA data

In the late 18th Century, a newly established sultanate in Muscat signed the first in a series of friendship treaties with Britain. Over time, Oman's dependence on British political and military advisors increased, but it never became a British colony.

In 1970, Qaboos bin Said Al-Said overthrew his father, and he has since ruled as Sultan. His extensive modernisation programme has opened the country to the outside world while preserving the longstanding close ties with the UK.

Oman's moderate, independent foreign policy has sought to maintain good relations with all Middle Eastern countries and joined the World Trade Organisation in 2000 and signed a free trade agreement with the United States in 2006.

Inspired by the popular uprisings that swept the Middle East and North Africa beginning in January 2011, Omanis began staging marches and demonstrations to demand economic benefits, an end to corruption, and greater political rights. In response to protesters' demands the Sultan pledged to implement wide-reaching reforms, such as granting legislative and regulatory powers to the Majlis al-Shura and introducing unemployment benefits.

In August 2012, the Sultan announced a royal directive mandating the speedy implementation of a national job creation plan for thousands of public and private sector jobs.

As part of the government's efforts to decentralise authority and allow greater citizen participation in local governance, Oman successfully conducted its first municipal council elections in December 2012. Announced by the Sultan in 2011, the municipal councils were granted the power to advise the Royal Court on the needs of local districts across Oman's 11 governorates.

Economy

Oman is a relatively small oil exporter, however, the government is trying to expand exports of natural gas, develop gas-based industries, and encourage foreign investment in petrochemicals, electric power, and telecommunications. It also stresses "Omanisation," whereby foreign workers are replaced with local staff to reduce chronically high unemployment.

Oman is a middle-income economy that is heavily dependent on dwindling oil resources. Due to declining reserves and a rapidly growing labour force, Muscat has actively pursued a development plan that focuses on diversification, industrialisation, and privatisation, with the objective of reducing the oil sector's contribution to GDP to 9% by 2020 and creating more jobs to employ the rising numbers of Omanis entering the workforce.

Tourism and gas-based industries are key components of the government's diversification strategy. However, increases in social welfare benefits, particularly since the Arab Spring, will challenge the government's ability to effectively balance its budget if oil revenues decline.

By using enhanced oil recovery techniques, Oman succeeded in increasing oil production, giving the country more time to diversify, and the increase in global oil prices during 2011 provided the government greater financial resources to invest in non-oil sectors.

In 2012, continued surpluses resulting from sustained high oil prices and increased enhanced oil recovery allowed the government to maintain growth in social subsidies and public sector job creation. However, the Sultan made widely reported statements indicating this would not be sustainable, and called for expanded efforts to support small to medium size enterprise development and entrepreneurship. In response, government agencies and large group companies announced new initiatives to spin off non-essential functions to entrepreneurs, incubate new businesses, train and mentor up and coming business people, and provide financing for start-ups.

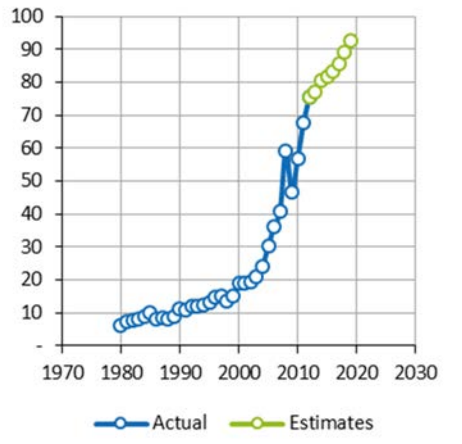
In response to fast growth in household indebtedness, the Central Bank reduced the ceiling on personal interest loans from 8% to 7%, lowered mortgage rates, capped the percentage of consumer loans at 50% of borrower's salaries for personal loans and 60% for housing loans, and limited maximum repayment terms to 10 and 25 years respectively.

In a final step towards privatisation, the Central Bank also issued final regulations governing Islamic banking in 2012, which precipitated the formation and subsequent Initial Public Offering ("IPO") of two "fully-fledged" Islamic banks and the formation of a sharia-compliant Islamic funding market.

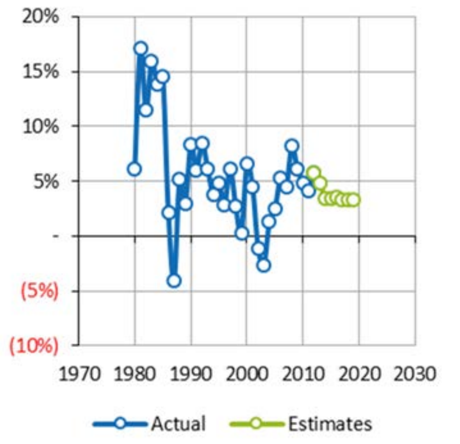
After solid GDP growth in 2004 – 2007, the economy slowed in 2008, and contracted in 2009, before returning to positive growth in 2010 – 2012 (Figure 63).

Figure 63 – Oman – GDP

$bn



% Growth



Source: IMF & SPA Data

Oil & Gas Sector

Reserves, Production, Demand & Exports

Oil

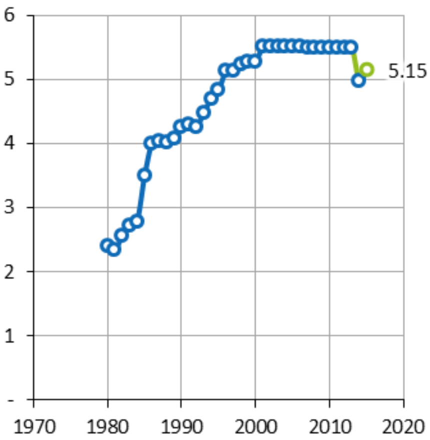
Oman's Ministry of Oil and Gas coordinates the state's role in the country's hydrocarbon sectors. Final approval on policy and investment, however, rests with the Sultan who also holds the office of Prime Minister. The implementation of oil policy is effected through an integrated company in which the Sultanate of Oman owns the majority stake. Petroleum Development Oman ("PDO") holds more than 90% of Oman's oil reserves and is responsible for 85% of its production. Aside from the Sultanate's 60% ownership, Shell (34%), Total (4%), and Portugal's Partex 2%) all own stakes in PDO.

Given the technical difficulties involved in production, the contract terms for international oil companies ("IOCs") have become more favourable than elsewhere in the region, with PDO yielding significant equity stakes in certain projects to encourage investment. Occidental Petroleum has the largest presence of any foreign firm and is the second largest oil-producer in Oman. Other major players with interests in Oman include: Shell, Total, Partex, BP, CNPC, KoGas, and Repsol.

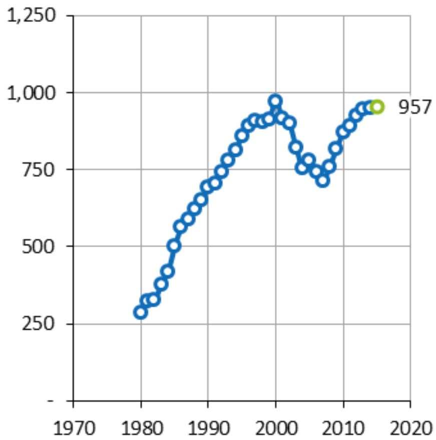
At the start of 2015 Oman had ~5.2bn bbl of proved reserves, up on the year previous, but significantly down on 2013. The changes in Oman's reserves are shown in Figure 64.

Figure 64 – Oman – Oil Sector Key Data

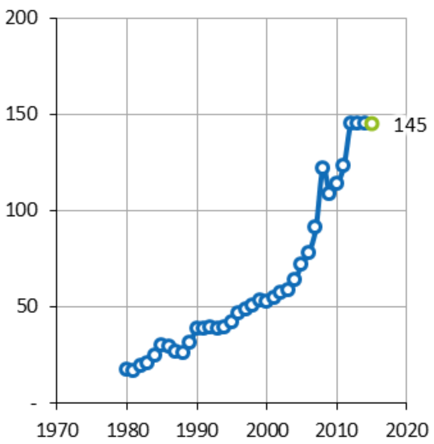
Reserves (bn bbl)



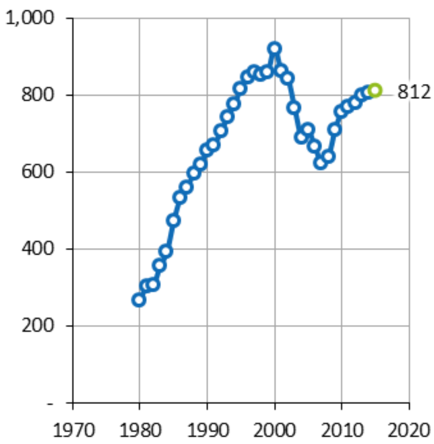
Production (m bpd)



Consumption (m bpd)



Exports (m bpd)



Source: EIA & SPA Data

Note:	Blue	1980 – 2013
	Green	2014

Oman is estimated to have produced 0.96mm bpd in 2015 (Figure 64), an increase of ~0.7% from 2014's production; Omani production accounted for 1.0% of the global total. In 2013, Oman consumed approximately 0.2mm bpd. Consumption has increased by >125% over the last decade, which has been largely been attributable to Oman's industrialisation and expanding petrochemical sector, along with improved roadways and an expanding vehicle fleet.

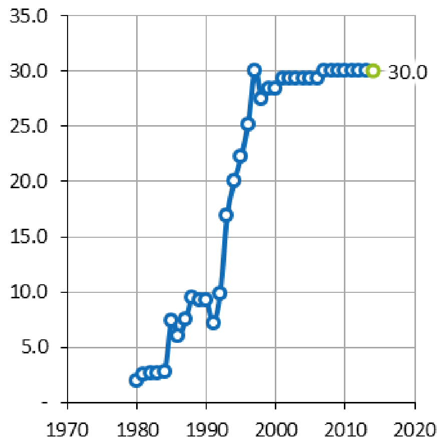
Though Oman is a significant net exporter of petroleum, it is not a member of OPEC. As is the case with other exports from the Gulf, Asia provides the main consumer markets for Omani crude; led by China, Thailand, South Korea, and Japan. Oman exported ~0.8mm bpd in 2015 (Figure 64), which accounted for ~85% of its production, an increase of 07% compared with 2015.

Gas

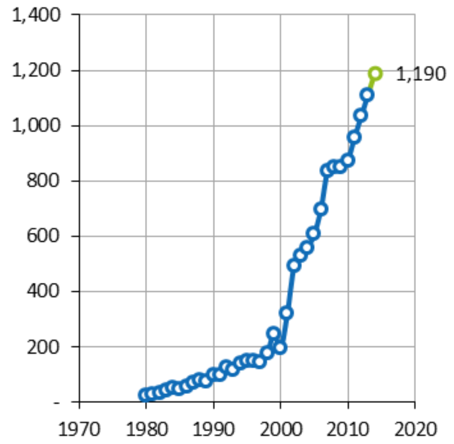
Oman held 30tcf of proved natural gas reserves as of January 2013 (Figure 65). In 2011, the country was the 5th largest dry natural gas producer in the Middle East and the 26th largest producer worldwide. Oman uses a significant portion of its natural gas production in oil extraction, re-injecting 22% of its dry production in 2012, according to IHS Global Insight.

Figure 65 – Oman – Gas Sector Key Data

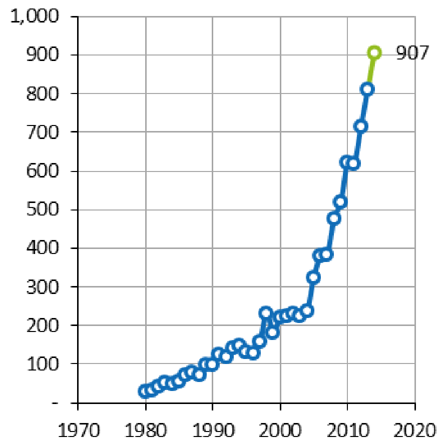
Reserves (tcf)



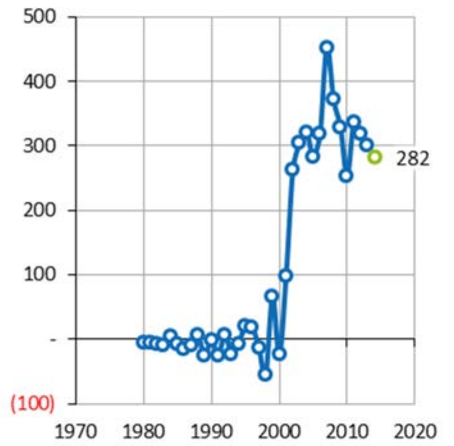
Production (bcf py)



Consumption (bcf py)



Exports (bcf py)



Source: EIA & SPA Data

Note:	Blue	1980 – 2013
	Green	2014

Oman's natural gas sector has grown in importance over the past decade, driven by the country's inauguration of two LNG facilities, in 2000 and 2005. Prior to 2000, when the Oman LNG facility opened, Oman produced small quantities of dry natural gas, averaging just 154bcf between 1990 and 1999. With the continuing rise of Oman's natural gas demand (168% increase between 2002 and 2011), Oman plans to divert all of its LNG exports towards the domestic market by 2024.

Infrastructure

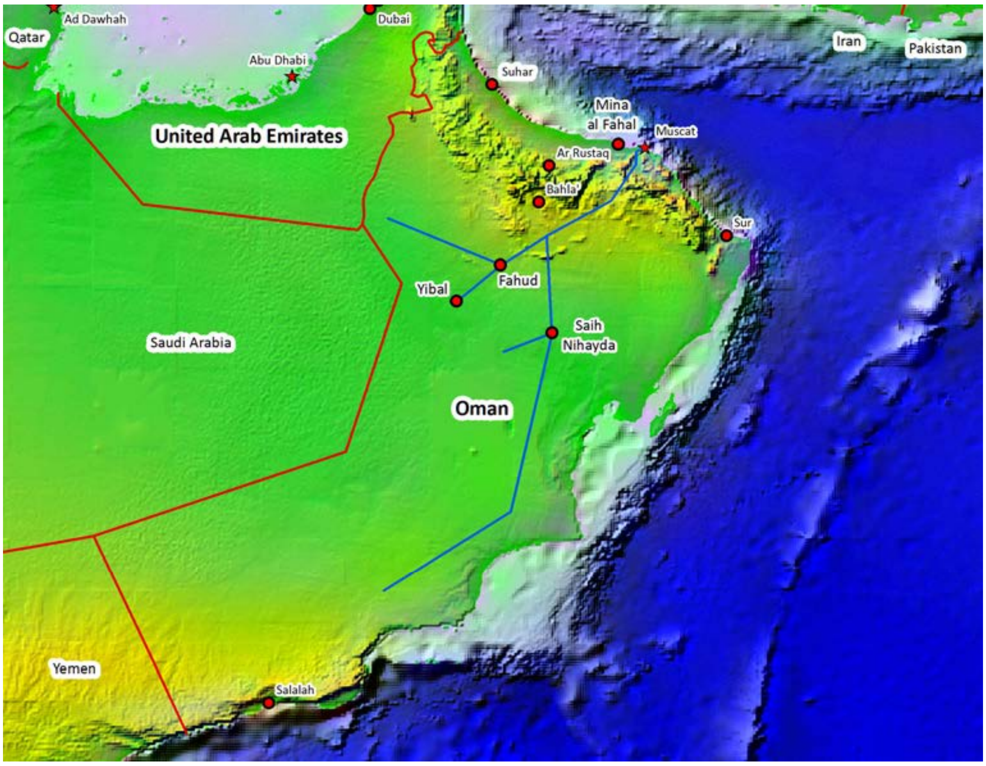
Oil

Oman's pipeline system is mostly focused on delivering crude oil to the country's only oil export terminal at Mina al-Fahal (Figure 66). Located near the capital, Muscat, both the export terminal at Mina al-Fahal and the Main Oil Line feeding the facilities are run by PDO.

Pipelines also feed industrial complexes and petrochemical plants, which form an integral part of economic diversification and Oman's expansion into downstream activities. PDO operates over 1,000miles of oil pipelines which run throughout the country. Additionally, the government has commissioned an export terminal at Suhar along with its plans to expand the Suhar refinery.

Figure 66 – Oman – Oil Infrastructure

Major Oil Infrastructure in Oman



Source: ESRI & SPA data

Gas

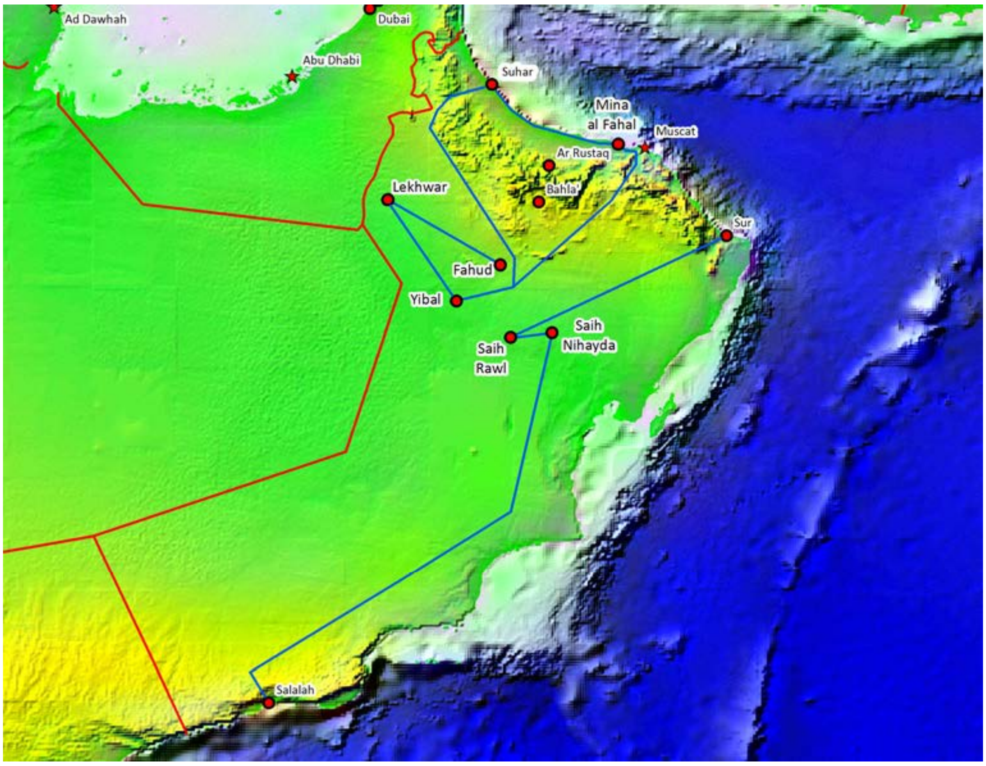
Oman has just one international natural gas pipeline, the Dolphin pipeline, which runs from Qatar to Oman via the United Arab Emirates. Oman is not a major importer of natural gas, although the country does import approximately 71bcf per year from Qatar via the Dolphin pipeline (Figure 67).

The imports via Dolphin are necessary to meet the rising level of domestic consumption inside Oman, which grew by nearly 390bcf between 2000 and 2011, prompting Oman LNG to announce that it would divert all of its currently-exported volumes of LNG away from foreign markets and toward domestic consumers by 2024.

Nearly all of Oman's exports go to Japan and South Korea, although in 2012 a small amount also went to China. Oman exported a total of 131 LNG cargoes in 2012, as well as 45 cargoes of NGLs, according to the Middle East Economic Survey.

Figure 67 – Oman – Gas Infrastructure

Major Gas Infrastructure in Oman



Source: ESRI & SPA data

In August 2013, Oman signed a memorandum of understanding with Iran on a natural gas import contract. If realised, it would be a $60bn, 25-year supply deal beginning in 2015, and will connect the two countries via a pipeline under the Gulf of Oman. Oman reportedly plans to use over 350bcf per year of the contracted volumes for domestic purposes and to process additional volumes of Iranian gas for export from its LNG terminals.

Fiscal Regime

Oman has a relatively standard form of PSC fiscal regime, with commercial terms negotiated on a contract-by-contract basis with the Ministry of Oil and Gas. Profit oil splits may be fixed, or on a sliding scale based upon production rates. Corporate income tax is paid on the contractors' behalf by the government. A range of bonuses, rentals and fees are payable. Oman's fiscal terms are summarised in Table 31.

Table 31 – Oman – Key Fiscal Terms

Category	Comment
Licence Terms	The exploration period of PSCs is typically between 3-6 years The exploitation period of PSCs is typically 20 years
Equity Participation	None
Bonuses, Rentals and Fees Signature Bonuses Payable	Bonus are payable upon making a commercial discovery, which is generally less than $2mm Production bonuses payable at negotiated levels of production, advancing in equal increments, typically from $1mm to $7mm Annual rental payable until commencement of regular exports from contract area No bonuses or rentals have been assumed for modelling purposes
Royalty	None

<table>
<tr><th>Category</th><th>Comment</th></tr>
<tr><td>PSC Cost Recovery</td><td>Cost recovery ceiling typically of 40% for oil developments and 60% for gas developments
Negotiated:
Oil 50%
Gas 60%
All legitimate operating and capital costs employed in exploration, development and production are cost recoverable
Bonus payments, Omani and foreign taxes and interest charges on funds borrowed are explicitly non-recoverable
Capital expenditure assumed depreciated on a straight-line basis over 5 years
Unlimited cost carry forward</td></tr>
<tr><td>PSC Profit Sharing</td><td>Production remaining after cost recovery is divided between the contractor and government with rates normally fixed at a single level
Oil
<table>
<tr><th>Rate (m bpd)</th><th>Contractor</th><th>Government</th></tr>
<tr><td>10></td><td>30%</td><td>70%</td></tr>
<tr><td>20</td><td>25%</td><td>75%</td></tr>
<tr><td>20<</td><td>20%</td><td>80%</td></tr>
</table>
Gas
35% share applies until production exceeds 150mm cfpd, when a 15% share applies</td></tr>
<tr><td>Corporate Income Tax Income</td><td>55% paid on behalf of the contractor by the Government</td></tr>
<tr><td>Ring Fencing</td><td>Production sharing is calculated at the PSC level</td></tr>
<tr><td>Product Pricing</td><td>In November 2006, the Ministry of Oil and Gas and Dubai Mercantile Exchange ("DME") announced that Oman would adopt forward pricing of its crude oil based on the daily settlement price of the DME's Oman Crude Oil Futures Contract
The Government retains the right to off-take non-associated gas for domestic consumption under a separate gas sales agreement at fair market value</td></tr>
</table>

Source: WoodMackenzie & SPA data

Operating in Oman

This is difficult to gauge accurately as it is subjective and dependent on each persons' perspective. Standard and Poor's ("S&P's") rates Oman's sovereign debt as A and its currency as A; a guide to S&P's ratings is provided in the *Appendix* (*Country Brief* – Page 130). As a guide, however, the Heritage Foundation's annual Index of Economic Freedom provides a good benchmark with which to start.

It is believed that in the short term (about 5 years), the existing ruling structure will remain in place, and will continue to implement the reforms that were precipitated by the Arab Spring and maintain its military ties with the West while nurturing cordial relations with Iran.

Strong domestic demand, expansionary fiscal policy and gains in the non-oil economy will ensure robust economic growth, averaging 4.2% in 2013 and 3.5% in 2014, with the main risk arising from a significant and extended downturn in oil prices; the estimated growth in GDP out to 2018 is shown in Figure 63. Oman is considered to be relatively low risk, with an overall rating of "A" (EIU); S&P rates its sovereign debt as "A". The key criteria are summarised in Table 32.

Table 32 – Country Risk Summary – Oman

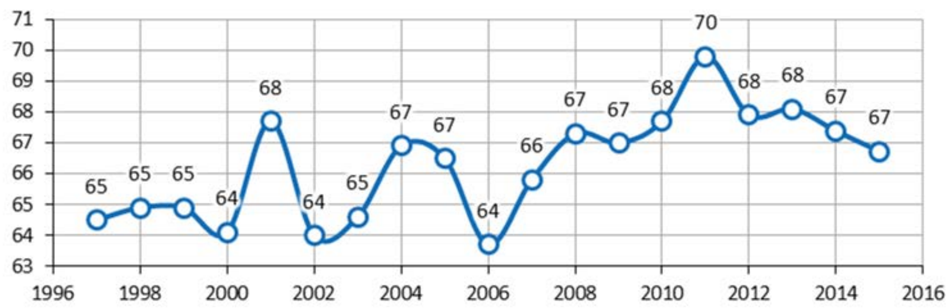
Category	Ranking	Comment
Sovereign Risk	A	Oman's public debt as a proportion of GDP is much lower than the median of other A-rated countries, as the government primarily uses oil revenue for project financing (rather than contracting debt). High oil prices will ensure fiscal and current-account surpluses, thereby supporting the rating.
Currency Risk	A	Foreign-exchange reserves provide comfortable import cover (equivalent to around five months). The Central Bank of Oman will maintain the riyal's peg to the US dollar during the forecast period.
Banking Sector Risk	BBB	Omani banks will remain vulnerable to concentrated lending to a small group of powerful businesses. Nevertheless, strong regulation and supervision, as well as banks' well-developed credit-risk-management systems, are supportive of the rating. The banking system is well capitalised and liquid.
Economic Structure Risk	BBB	Oman has a very young population, with over half under the age of 20. Many Omanis lack the technical expertise to contribute to the diversification programme. Oman remains dependent on oil and gas.
Political Risk	BB	The political situation in Oman has stabilised following the implementation of political reforms and economic measures to boost employment, but the risk of further unrest cannot be ruled out if the reform process grinds to a halt.

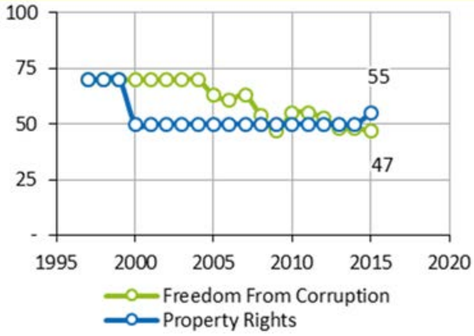
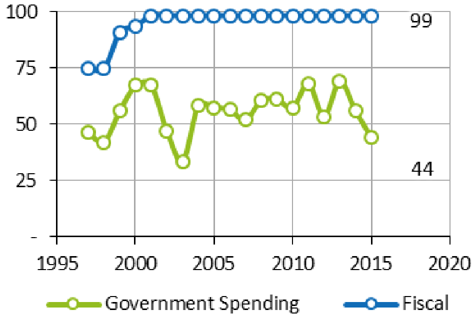
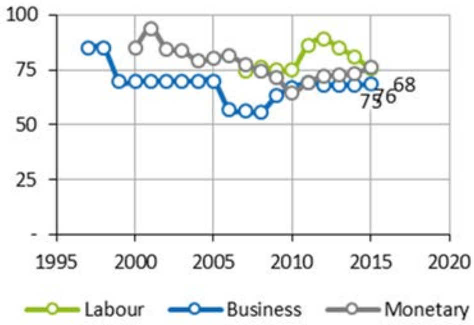
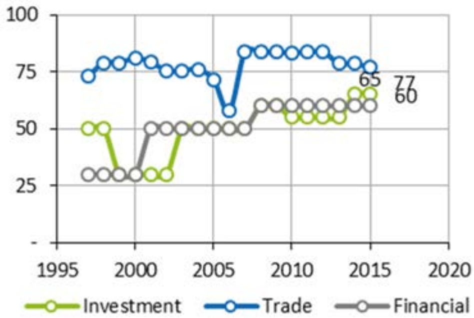
Source: EIU

Oman's economic freedom score is 66.7, making its economy the 56th freest in the 2015 Index. Its score is 0.7 point lower than last year due to declines in the management of government spending and labour freedom that outweigh improvements in investment freedom and monetary freedom. Oman is ranked 6th out of 15 countries in the Middle East/North Africa region, and its overall score is above the world and regional averages; the Heritage Index for Oman is summarised in Figure 68.

Figure 68 – Oman – Heritage Index Scores

Economic Freedom Score



Category	Chart
Rule of Law Although corruption has not been perceived as serious, the public has recently shown heightened awareness of it despite the lack of freedom of information provisions in the legal code. In 2012, public-sector employees became subject to financial disclosure requirements. The judiciary is not independent and remains subordinate to the sultan and the Ministry of Justice. Property rights are well protected.	
Limited Government Oman has no income tax, and the corporate tax rate is 12%. There is also no consumption tax or value-added tax (VAT). The overall tax burden is 2.2% of gross domestic income. Government expenditures equal about 38% of GDP. Oil and gas revenues, which constitute 84% of total revenue, have helped to keep public debt low at less than 10% of GDP.	
Regulatory Efficiency Launching a business takes five procedures, but minimum capital requirements equal over twice the level of average annual income. Obtaining necessary permits takes more than 150 days. Discouraging more dynamic job growth, labour laws enforce the "Omanisation" policy that requires private-sector firms to meet quotas for hiring native Omani workers. The state influences prices through an extensive subsidy system.	
Open Markets Oman's average tariff rate is 3.2%. Licensing procedures for several products deter imports. Foreign investors may not own land. The financial sector continues to evolve, and commercial banks perform well. Most credit is offered at market rates, but the government uses subsidised loans to promote investment. The Muscat Securities Market is active and open to foreign investors.	

Source: Heritage Index of Economic Freedom & SPA data
Note: For details on each of the sectors, see *Heritage Foundation's Measurement of Economic Freedom* (Page 131)

United Arab Emirates

The United Arab Emirates ("UAE") is heavily dependent on Oil & Gas revenues, however, the contribution to revenues from differing sectors such as tourism and trade has been promoted. While Oil & Gas investment has waned modestly, access to the Oil & Gas segment is restricted and tightly controlled. However, the emirates such as Ras Al Khaimah and Sharjah are starting to open up access to more commercially focused Junior E&P companies; we provide a summary in Table 33.

Table 33 – United Arab Emirates – Section Summary

Section	Content	Page
Introduction	Further information about the UAE's economy can be found in the *Appendix* (*Country Brief Supplement* – Page 130).	104
Oil & Gas Segment	Oil & Gas is essential to the UAE's economy, and as such enjoys effective and widespread support in country. While the national oil company (ENOC) is involved at every stage of the cycle, its approach to regulation is open and fair.	105
Fiscal Regime	The UAE generally operates a tax/royalty regime, with state participation possible. Negotiations for licences is conducted directly with the Governments of the individual Emirates or with the Petroleum Councils where they exist. Detailed fiscal terms are negotiable on a case-by-case basis. Although rare, a direct state participation option is limited to Abu Dhabi and Sharjah where the State can exercise a participation option of up to 60%; to date, this option has only been exercised on three occasions.	109

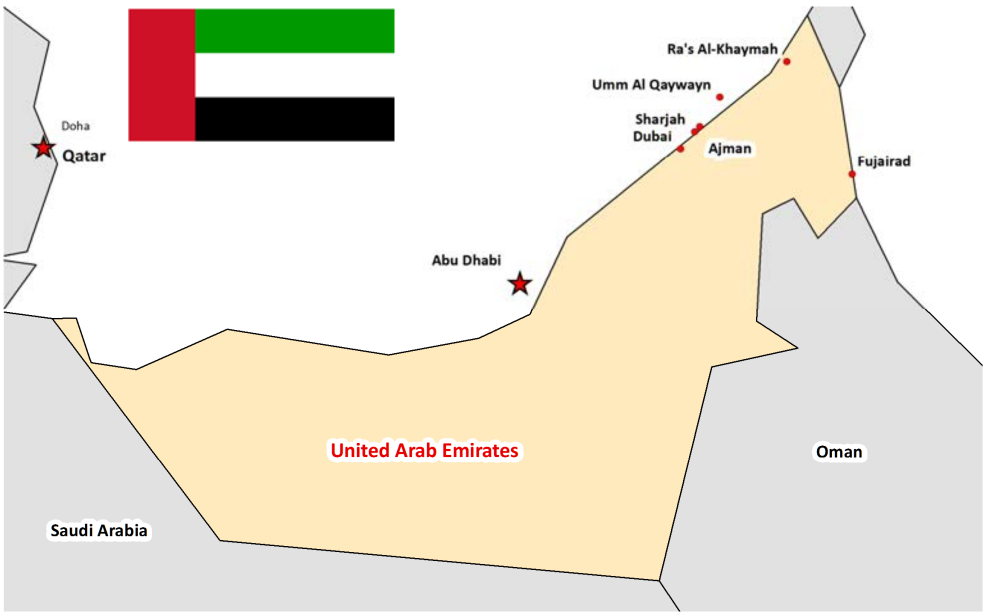
Source: SPA data

Introduction

The United Arab Emirates ("UAE") is located in the Middle East, bordering the Gulf of Oman and the Persian Gulf, between Oman and Saudi Arabia (Figure 69). The Trucial States of the Persian Gulf coast granted the UK control of their defence and foreign affairs in 19th century treaties. In 1971, six of these states – Abu Dhabi, Ajman, Al Fujayrah, Sharjah, Dubai, and Umm al Qaywayn – merged to form the United Arab Emirates ("UAE"); they were joined in 1972 by Ras Al Khaimah.

Figure 69 – United Arab Emirates – Map

General Location



Source: ESRI & SPA Data

Economy

The UAE's per capita GDP is on par with those of leading West European nations. Its high oil revenues and its moderate foreign policy stance have allowed the UAE to play a vital role in the affairs of the region. For more than three decades, oil and global finance drove the UAE's economy.

However, in 2008 – 2009, the confluence of falling oil prices, collapsing real estate prices, and the international banking crisis hit the UAE especially hard. The UAE has essentially avoided the "Arab Spring" unrest seen elsewhere in the Middle East, though in March 2011, political activists and intellectuals signed a petition calling for greater public participation in governance that was widely circulated on the Internet. In an effort to stem potential further unrest, the government announced a multi-year, $1.6bn infrastructure investment plan for the poorer northern Emirates.

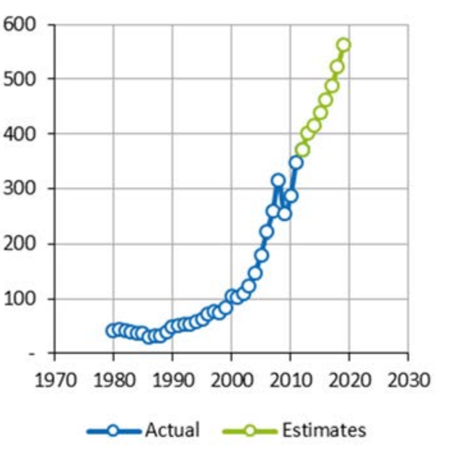
The global financial crisis, limited liquidity in the debt markets and deflated asset prices precipitated a contraction in the economy in 2009. UAE authorities attempted to limit the impact of the crisis by increasing public spending on infrastructure projects and boosting liquidity in the banking sector. The crisis hit Dubai hardest, as it was heavily exposed to depressed real estate prices. Dubai lacked sufficient cash to meet its debt obligations, prompting global concern about its solvency.

The UAE Central Bank and Abu Dhabi-based banks bought the largest shares. In December 2009 Dubai received an additional $10bn loan from the emirate of Abu Dhabi. Dependence on oil, a large expatriate workforce, and growing inflation pressures are significant long-term challenges. The UAE's strategic plan for the next few years focuses on diversification and creating more opportunities for nationals through improved education and increased private sector employment.

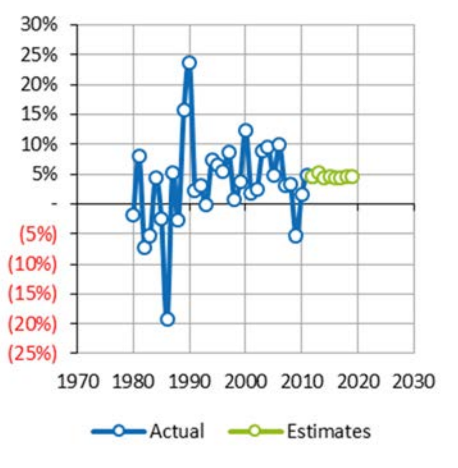
After solid GDP growth in 2004 – 2007, the economy slowed in 2008, and due to the financial crisis, contracted in 2009. The debt restructuring and investment in infrastructure precipitated the UAE's returning to positive growth in 2010 – 2012 (Figure 70).

Figure 70 – United Arab Emirates – GDP

$bn



% Growth



Source: IMF & SPA Data

Oil & Gas Sector

Reserves, Production, Demand & Exports

Oil

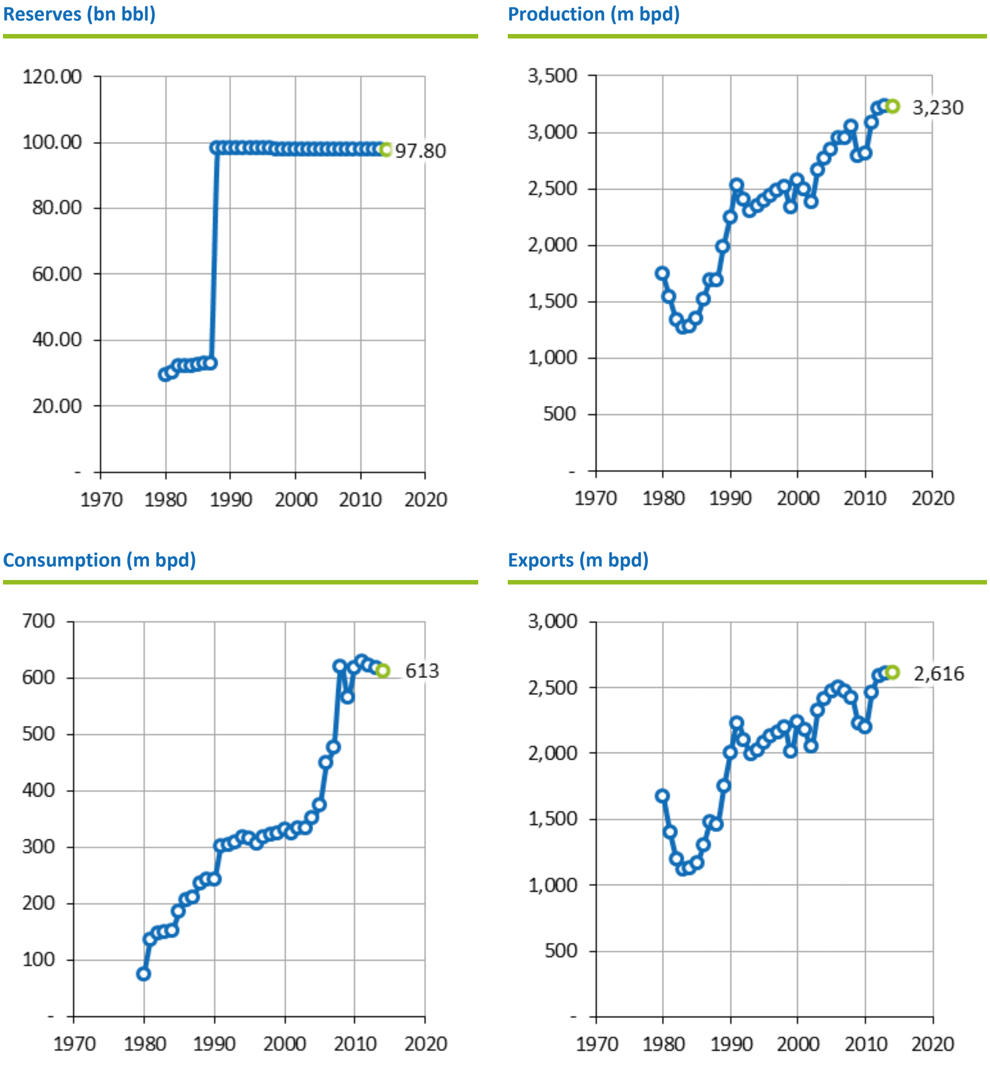
Abu Dhabi National Oil Company's ("ADNOC's") subsidiaries are organised into six different categories, including oil and gas exploration, processing, and distribution, among others. Some of the most notable of these subsidiaries are the Abu Dhabi Company for Onshore Oil Operations ("ADCO"), the Abu Dhabi Marine Operating Company ("ADMA-OPCO"), the Zakum Development Company ("ZADCO"), and the Abu Dhabi National Tanker Company

("ADNATCO"), which is operated under the same management team as the National Gas Shipping Company ("NGSCO"). ADNATCO has a fleet of 22 vessels, including two oil tankers, nine bulk carriers, and four crude tankers.

Dubai's energy sector is run by the Dubai Supreme Council of Energy ("DSCE"), which oversees the Emirate's energy-policy development and coordination. The DSCE includes representatives from several key entities, including the Emirates National Oil Company ("ENOC"), the Dubai Petroleum Establishment ("DPE"), and the Dubai Nuclear Energy Committee ("DNEC"). The DSCE seeks to ensure that Dubai's economy has adequate and sustainable access to energy resources.

Information about energy sector organisation in the other Emirates is limited, however, each emirate does have its own "national" oil company, such as Ras Al Khaimah. At the start of 2013, the UAE had ~98bn bbl of proved reserves, flat in comparison to 2012. The changes in the UAE's reserves are shown in Figure 71.

Figure 71 – United Arab Emirates – Oil Sector Key Data



Source: EIA & SPA Data
Note: Blue 1980 – 2013
Green 2014

The UAE is estimated to produce 3.7mm bpd in 2015, an increase of ~7% from 2014's production of 3.4mm bpd; the UAE's production accounted for 3.6% of the global total. Given that UAE demand in 2015 estimated demand is expected to be 0.61mm bpd, a decline of 0.80% from that in 2014. Exports have continued to rise in line with production; 2015 is anticipated to be up ~9% to 3.1mm bpd (Figure 71).

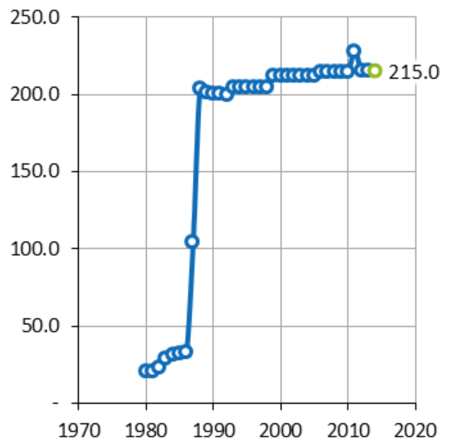
Historically, gasoline has been heavily subsidised in the country, and while the subsidies are politically popular, some analysts believe they encourage wasteful practices. Over the past 10 years, the annual growth rate of oil consumption was 4.3%, and positive economic growth forecasts indicate that while this trend is likely to continue in the near to medium term at least, the gradual tapering of the subsidies should continue to check the growth in demand.

Gas

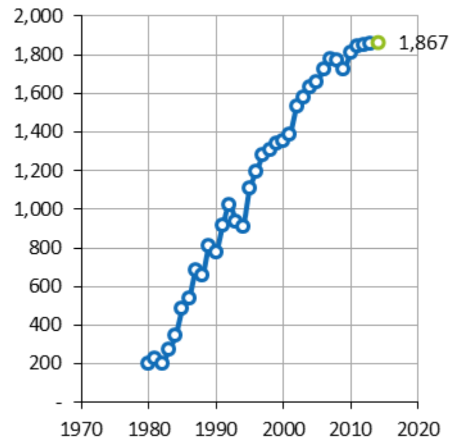
The UAE holds the seventh-largest proved reserves of natural gas in the world, at just over 215tcf (Figure 72). Nevertheless, the UAE has been a net importer of natural gas since 2008, due principally to two main reasons: (i) the UAE re-injects approximately 26% of gross natural gas production into its oil fields as part of EOR techniques; and (ii) the country's inefficient and rapidly-expanding electricity grid — already taxed by the swift economic and demographic growth of recent decades — relies on electricity from natural gas-fired facilities.

Figure 72 – United Arab Emirates – Gas Sector Key Data

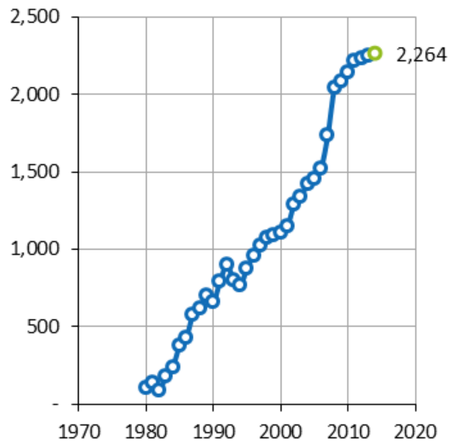
Reserves (tcf)



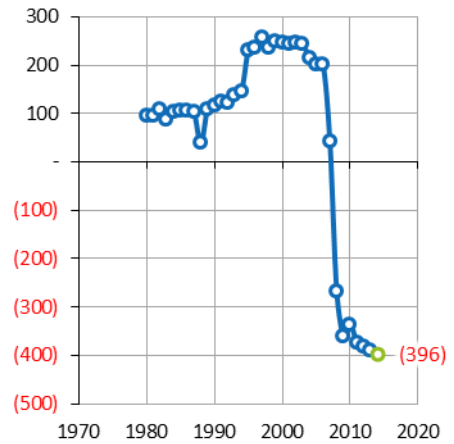
Production (bcf py)



Consumption (bcf py)



Exports (bcf py)



Source: EIA & SPA Data

Note: Blue 1980 – 2013
Green 2014

To help meet the growing demand for natural gas, the UAE boosted imports from neighbouring Qatar via the Dolphin Gas Project's pipeline over the past several years. The pipeline runs from Qatar to Oman via the UAE and is one of the principal points of entry for the UAE's natural gas imports.

The UAE's natural gas has a relatively high sulphur content that makes it highly corrosive and difficult to process. For decades, the country simply flared the gas from its oil fields rather than undertake the extensive—and expensive—processes associated with separating the sulphur from the gas.

The technical difficulties of producing the country's sour gas once posed a great impediment to the development of the UAE's reserves, but advances in technology and the growing domestic demand for natural gas make the country's vast reserves an enticing alternative to Qatari imports.

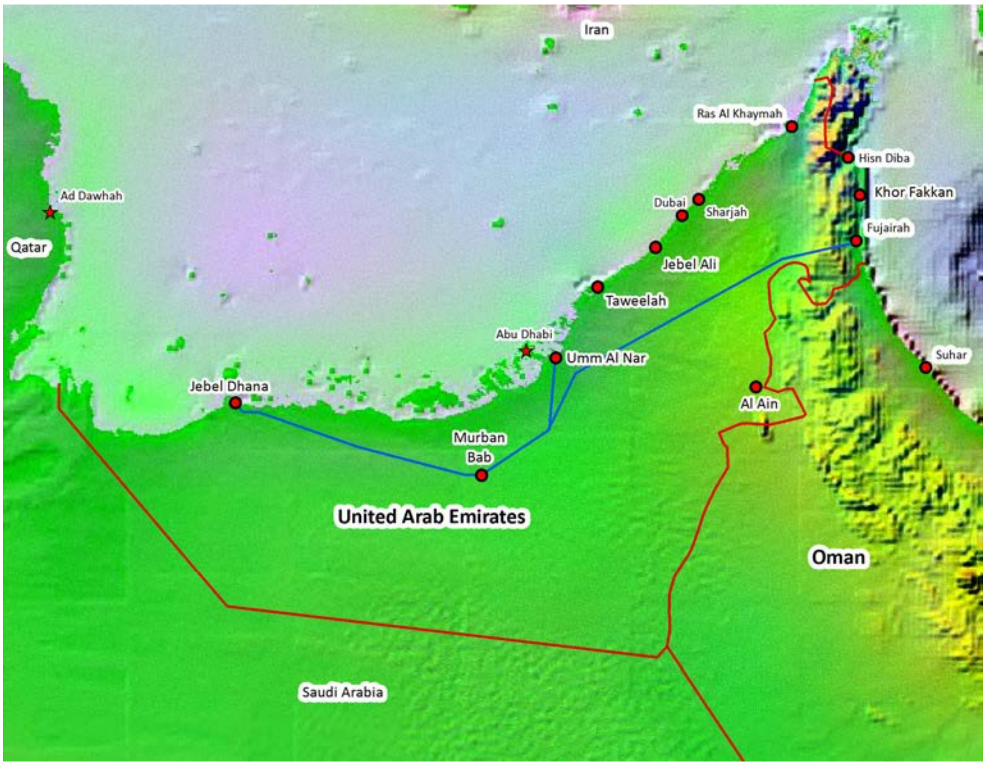
Infrastructure

Oil

The UAE has a well-developed domestic pipeline network, which links oil fields with processing plants and export terminals. The newest export pipeline, the Abu Dhabi Crude Oil Pipeline ("ADCOP"), runs 230 miles from Habshan to Fujairah; it began operations in June 2012 (Figure 73).

Figure 73 – United Arab Emirates – Oil Infrastructure

Major Oil Infrastructure in in UAE



Source: ESRI & SPA data

The pipeline gives the UAE a direct link from the rich fields of its western desert to the Gulf of Oman to the export markets. ADCOP provides the UAE and global markets a strategic alternative to the problematic Strait of Hormuz, which is the world's most important energy chokepoint.

The ADCOP boosted UAE crude oil export capacity when it began operations in June of 2012. The UAE's export capacity ranks it 5th in the world, behind Saudi Arabia, Russia, Iran, and Nigeria.

Approximately 95% of UAE's exports are sent to Asian markets, with the largest share going to Japan; the majority of exports is sold on a term basis. Currently the UAE has six export terminals with the capability to handle crude oil, but only the terminal in Fujairah is free from the risks associated with the Strait of Hormuz.

The export terminal in Fujairah has been earmarked for expansion and is set to expand its capabilities to include three new subsea loading lines, an intermediate pumping station, and three offshore buoys designed for deep-water tanker loading. A 250m bpd refinery is also being planned, which will provide fuel for both domestic and export markets.

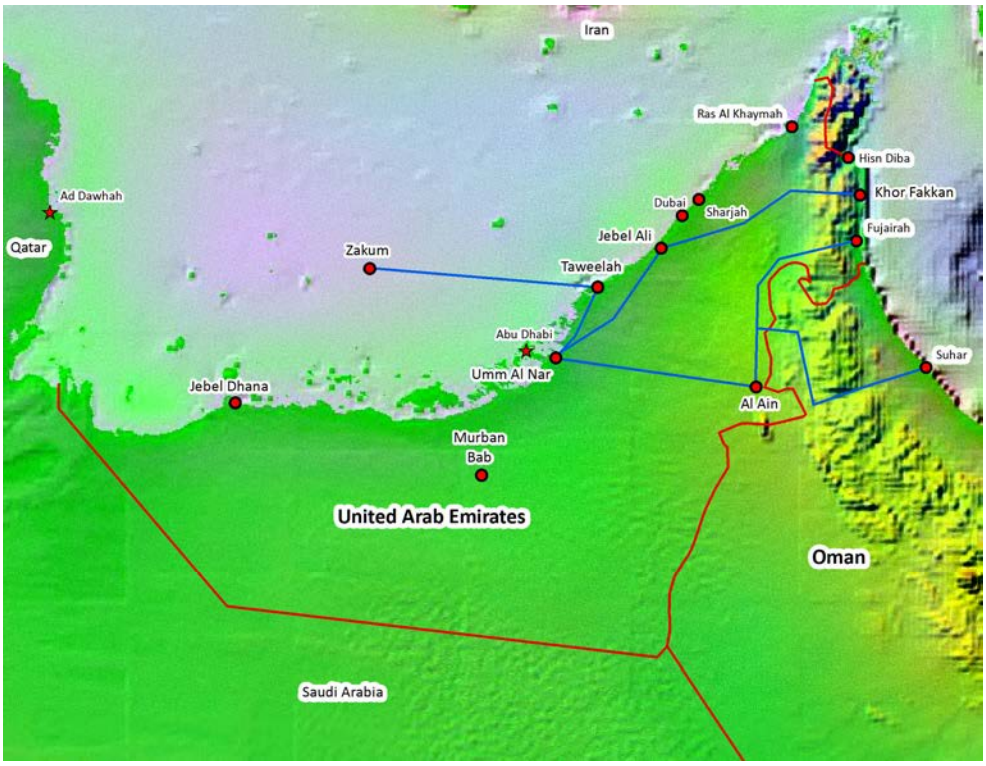
The Fujairah facility has a storage capacity of 8mm bbl of crude, which will be increased to 12mm bbl in the near future. Given its strategic important, Fujairah has become a critical part of the node in what is becoming a well-developed export network

Gas

While the UAE is a net gas importer, the country does also export gas via is limited infrastructure (Figure 74). In 1977, the UAE became the first country in the Middle East to export LNG, sending its first load to the Tokyo Power Company ("TEPCO") as part of a long-term supply agreement.

Figure 74 – United Arab Emirates – Gas Infrastructure

Major Gas Infrastructure in the UAE



Source: ESRI & SPA data

The UAE signed a second contract in 1990 to double LNG exports to Japan, and in 1994, a third LNG train at Das Island began operation to help fulfil the terms of the agreement. The terminal at Das Island has a capacity of 6mm tpy of LNG, 2.7mm tpy of LPG (~31mm boe), and almost 1mm tpy of other associated products.

Plans are moving forward to increase the capacity of the first two LNG trains substantially, by a reported 10mm tpy, expected to be commissioned around the same time the contract with TEPCO expires (2019).

Fiscal Regime

Negotiations for licences is conducted directly with the Governments of the individual Emirates or with the Petroleum Councils where they exist. Detailed fiscal terms are negotiable on a case-by-case basis. Although rare, a direct state participation option is limited to Abu Dhabi and Sharjah where the State can exercise a participation option of up to 60%; to date, this option has only been exercised on three occasions.

The concession-based fiscal regimes are usually fairly simple, with royalty and corporate income tax payable, both of which may either be fixed rates, or sliding-scale rates based on production levels. A range of bonuses, rentals and fees are also payable; the key terms are summarised in Table 34.

Table 34 – UAE – Key Fiscal Terms

Category	Comment
Licence Terms	Negotiations for exploration and production acreage conducted directly with the Governments of the individual Emirates or with the Petroleum Councils where they exist. Detailed fiscal terms are negotiable on a case-by-case basis. The contract term varies by Emirate. Recent agreements in Abu Dhabi, Sharjah and Dubai have had terms of 35 years, while agreements in Umm Al Qaiwain and Ajman have had terms of 25 and 40 years, respectively. The term of exploration phases can also vary. Recent contracts in Abu Dhabi have ranged from 8 to 10 years with a company having the right to relinquish all or any part of the concession area at any time
Equity Participation	Direct state participation option is limited to Abu Dhabi and Sharjah where the State can exercise a participation option of up to 60%. To date, this option has only been exercised on three occasions and no equity is assumed in our valuations.
PSC Cost Recovery	The UAE does not generally provide for cost recovery. However, the current contract terms provide for a PSC type arrangement for the recovery of costs Negotiated: Ras Al Khaimahh 0% Sharjah 0%
PSC Profit Sharing	**Emirate** / **Contractor** / **Government** Ras Al Khaimahh 40% 60% Sharjah 100% 0%
Bonuses, Rentals and Fees Signature Bonuses Payable	In Abu Dhabi, signature bonuses have ranged from \$1mm to \$5mm while in other Emirates they generally range from \$0.2mm to \$0.5mm. Production bonuses are commonly payable upon commercial production start-up and at tiered production levels, typically 100m, 200m and 500m bpd. Bonuses in Abu Dhabi have ranged from \$2mm to \$10mm whilst other Emirates range from \$1.5mm to \$5mm. Discovery bonuses range from \$2mm to \$5mm in Abu Dhabi and from \$1mm to \$2mm in other Emirates. Annual rentals are generally payable up until first production with annual payments typically in the \$0.1mm to \$0.3mm range. They are commonly increased during the interval between commercial discovery and first production

Category	Comment	
Royalty	Varies by emirate	
	Negotiated:	
	Ras Al Khaimah 0%	
	Sharjah	
	Production (m bpd)	**Royalty**
	10>	12%
	20	13%
	30	14%
	50	15%
	100	16%
	200	18%
	200<	20%
Corporate Income Tax Income	Income tax is levied on gross revenue, less royalty, operating costs and depreciation	
	The tax rate varies between 55% and 85% and may be linked to production rates	
	Tangible capital costs are depreciated on a straight-line basis over ten years for oil and over five years for gas	
	Losses may be carried forward indefinitely	
	Note: in certain concessions for the development of discovered fields (known as "operating contracts") royalty is payable at 20% and tax at 85%. If this results in a net profit margin of less than $1/bbl for the contractor, the royalty/tax bill is reduced to achieve the margin. If the contractor's margin exceeds $1/bbl, tax is increased to achieve the margin	
	Negotiated:	
	Ras Al Khaimah 47%	
	Sharjah	
	Rate (m bpd)	**Tax**
	10>	50%
	20	60%
	30	70%
	50	75%
	50<	80%
Ring Fencing	Royalty and tax are calculated at the concession level	
Product Pricing	For liquids, royalty and tax calculations are commonly based on the posted price for the crude	
	The Government Sales Price is generally fixed at 93% of the posted price	

Source: WoodMackenzie & SPA data

Operating in the United Arab Emirates

The economy performs competitively in many areas, barriers to trade are quite low, and commercial operations are aided by regulations that support open-market policies. With a transparent and favourable business climate and a high degree of political stability, the UAE has created a dynamic environment for entrepreneurs.

Growth is forecast to be modest in 2013 in light of uncertain global economic conditions and is forecast to average 5.1% in 2013 – 2017. Tightening banking sector regulation will be a priority. The UAE is considered to be relatively low risk, with an overall rating of "BB"; S&P rates its sovereign debt as "A." The EIU's summary of the key criteria is provided in Table 35.

Table 35 – Country Risk Summary – United Arab Emirates

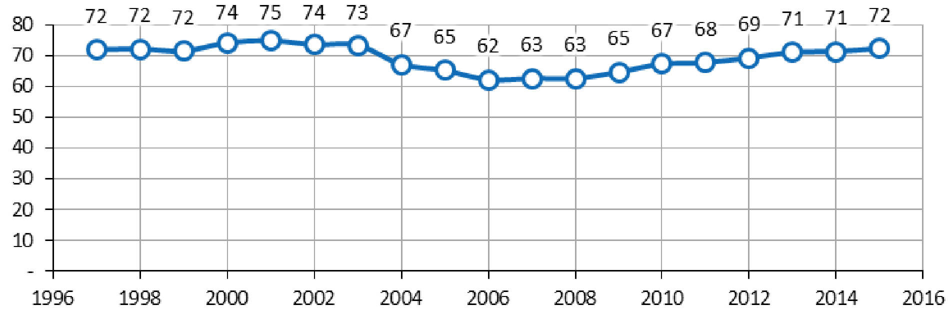
Category	Ranking	Comment
Sovereign Risk	BB	The score for sovereign risk is underpinned by fiscal-account surpluses and the large stock of foreign assets held by the UAE's sovereign wealth funds. Dubai entities have around UMYR9.4bn in debt maturing in 2013 but should be able to avoid refinancing problems, although the euro zone crisis poses a risk.
Currency Risk	BBB	The UAE dirham will be susceptible to fluctuations in the US dollar, to which it is pegged. However, with the dollar not expected to suffer major weakness in 2013, especially as the euro zone crisis continues, there is no risk of the dirham being depegged.
Banking Sector Risk	BB	Banks' profits continued to grow in 2012 on the back of rising income and a decline, in some cases, in provisioning levels. However, banks face a challenging year in 2013, owing to tighter lending regulations initiated by the Central Bank of the UAE to improve credit management.
Economic Structure Risk	B	High oil prices and earnings from foreign assets will continue to support the economy. However, its openness makes it susceptible to external shocks.
Political Risk	BB	The UAE's location presents considerable political risk. Geopolitical tensions involving Iran's nuclear programme will remain high despite the restart of talks.

Source: EIU

The UAE's economic freedom score is 72.4, making its economy the 25th freest in the 2015 Index. Its score is 1.0 point higher than last year, with improvements in investment freedom, the management of government spending, and freedom from corruption that outweigh a small combined decline in monetary freedom, trade freedom, and fiscal freedom. The UAE is ranked 2nd out of 15 countries in the Middle East/North Africa region, and its overall score is higher than the world and regional averages. The Heritage score for the UAE follows in Figure 75.

Figure 75 – Heritage Index Scores – United Arab Emirates

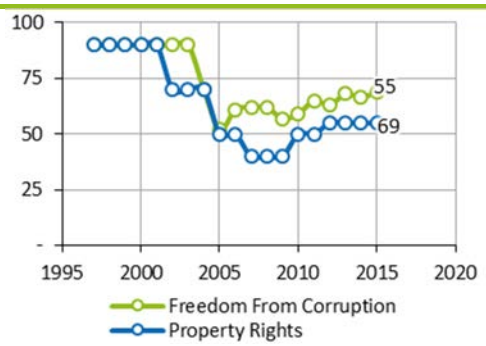
Economic Freedom Score



Category	**Chart**

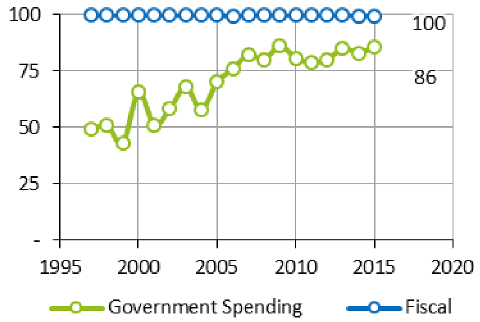
Rule of Law

The UAE is considered one of the least corrupt countries in the Middle East. The rule of law is relatively well-maintained, but the judiciary is not independent, and court rulings are subject to review by the political leadership. All land in Abu Dhabi, largest of the seven emirates, is government-owned. Non-citizens are allowed to own property only in certain areas.



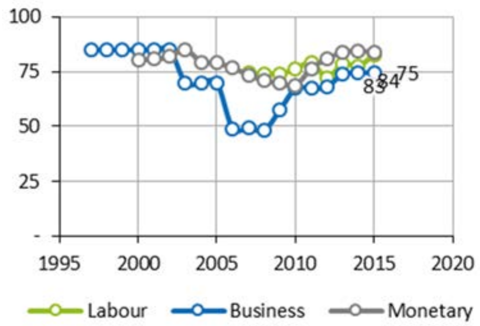
Limited Government

The UAE has no income tax and no federal-level corporate tax. In some emirates, different corporate taxes exist for certain business activities. There are few other taxes, and the overall tax burden is quite low at 6.1% of the economy. Government spending is 24% of gross domestic output. Public debt is low at about 18% of GDP. Oil and gas revenues contribute significantly to public spending.



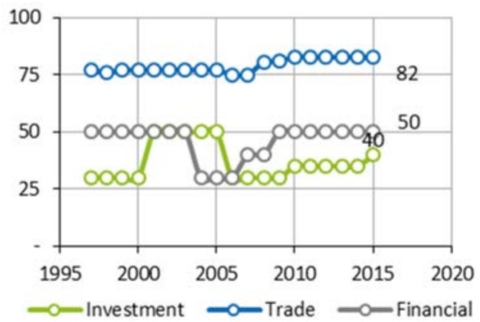
Regulatory Efficiency

Launching a business takes six procedures and eight days, and no minimum capital is required. Licensing requirements have been streamlined and are less costly, but completing them still takes over a month. Employment regulations are relatively flexible, and the non-salary cost of employing a worker is moderate. Continued restructuring of heavily subsidised and indebted government-related entities ("GREs") is needed.



Open Markets

The UAE's average tariff rate is 3.7%. Non-tariff barriers are not a significant deterrent to trade. Foreign ownership in many sectors of the economy is capped at 49%. The modern financial sector is efficient and competitive. Banks offer a full range of services. Islamic banking is increasingly prominent. State-owned banks have maintained a strong presence, but foreign banks have over 100 branches around the country.



Source: Heritage Index of Economic Freedom & SPA data
Note: For details on each of the sectors, see *Heritage Foundation's Measurement of Economic Freedom* (Page 131)

While the political landscape is expected to remain stable, a transfer of power in Abu Dhabi from the current ruler to the crown prince cannot be discounted as major reshuffles have been implemented in government. Regional tensions remain high given the on-going diplomatic impasse over Iran's nuclear programme.

Successful efforts at economic diversification have reduced the portion of GDP based on oil and gas output to 25%. The UAE's establishment of "Free Trade Zones" such as the Jebel Ali Free Zone Authority ("JAFZA"), which offers 100% foreign ownership and zero taxes to companies whose operations are not based in the UAE, have attracted significant investment income in to the country.

Key Officers

Board of Directors

Zainul Rahim bin Mohd Zain — Non-Executive Chairman

Zainul Rahim bin Mohd Zain, a Malaysian aged 61, was appointed to the Board on 14 December 2010. He is a member of the Audit and Risk Management, Nominating and Remuneration Committees.

Zainul graduated with a Bachelor of Engineering, majoring in Mechanical Engineering from the University of Western Australia, Australia.

Zainul began his career at Shell Malaysia Exploration and Production (SM-EP) in 1978 as a Wellsite Petroleum Engineer. He held various positions in drilling engineering, petroleum engineering, and information management & technology in SM-EP and during his two assignments in the Netherlands.

He was General Manager of SM-EP's Business Services (1997), Technical Services (1999) and the Sarawak Business Unit (2000), before being appointed as Deputy Chairman and Executive Director of Shell Malaysia in December 2001. In July 2003, he double-hatted as Shell Asia Pacific Region's Transition Director based in Singapore. In November 2005, he was appointed to the position of Chairman of Shell companies in Egypt and Managing Director of Shell Egypt N.V., before retiring from the Shell Group on 30 June 2008.

During his tenure as Deputy Chairman of Shell Malaysia, he sat on the boards of 12 companies, including Shell Malaysia Ltd, Shell MDS Sdn Bhd, Shell Trading Sdn Bhd, Sarawak Shell Bhd, Sabah Shell Petroleum Company Ltd and CS Mutiara Sdn Bhd. He was also Chairman, Director and member of various NGOs, including the Society of Petroleum Engineers AsiaPac, Business Council for Sustainable Development Malaysia, Petroleum Industry of Malaysia Mutual Aid Group and Malaysian International Chamber of Commerce and Industry. While in Egypt, he chaired Shell Egypt's Country Coordination Team and Shell Express CNG, and sat on the boards of Shell Egypt N.V., Shell Egypt Deepwater B.V. and Bapetco.

Zainul sat on the Supervisory Committee of Sime Darby's Energy & Utilities Division for two years until 2010. He currently sits on the boards of UKM Holdings Sdn Bhd, Bank Pembangunan Malaysia Bhd, Camco Clean Energy Plc, and Cenergi SEA Sdn Bhd (formerly known as CSEA Clean Energy Sdn Bhd).

Dr Kenneth Gerard Pereira — Managing Director

Dr Pereira, a Malaysian aged 56, has been the Managing Director of Hibiscus Petroleum Berhad since 13 September 2010. He holds a Bachelor of Science (Honours) degree in Engineering from the University of Bath, United Kingdom; a Masters in Business Administration from Cranfield University, United Kingdom; and a Doctorate in Business Administration from the University of South Australia, Australia.

Dr Pereira has 30 years' experience in the oil and gas industry, both in the services and exploration and production sectors. He began his career in the wireline and testing division of Schlumberger Overseas S.A in 1983 as a Field Service Engineer working in Brunei, Thailand, France, Libya, Italy, Norway and Tunisia. In 1990, he joined the Sapura Group, overseeing the service of telecommunication products and later, moved to the Group Corporate Planning Department.

In 1997, he was appointed as Vice President of Energy Sector Projects and initiated the building of the oil and gas services business of the Company under the Sapura Energy Sendirian Berhad banner. Between 1997 and 2001, several service based businesses in the oil and gas value chain were grown organically or acquired. In 2003, the Sapura Group successfully acquired Crest Petroleum Berhad and he became the Chief Operating Officer (COO) of SapuraCrest Petroleum Berhad (now part of SapuraKencana Petroleum Berhad Group), an oil and gas services company listed on the Main Market of Bursa Malaysia Securities Berhad. He resigned from SapuraCrest Petroleum in 2008 to complete his doctoral research.

In 2009, Dr Pereira became Managing Director of Interlink Petroleum Ltd, an oil and gas exploration and production company listed on the Mumbai Stock Exchange. He remained in the position until early 2011. In 2009, he was also appointed to the board of STP Energy Pte Ltd, a privately held Singaporean company with offshore oil and gas exploration interests in New Zealand.

Dr Pereira holds directorships in all of Hibiscus Petroleum’s subsidiaries and other various private companies, including Masirah Oil Limited, a company holding offshore interest in Block 50, in the Sultanate of Oman. In July 2012, he was appointed Chairman of the board of Lime Petroleum Plc, a joint venture between Hibiscus Petroleum and Rex International Holdings, a company listed on the catalist board of the Singapore Stock Exchange

Dr Pereira is also currently the Chairman of the Development Committee of the Malaysian Hockey Confederation.

Datuk Zainol Izzet bin Mohamed Ishak Non-Executive Director

Datuk Zainol Izzet bin Mohamed Ishak, a Malaysian aged 53, was appointed to the Board on 13 September 2010 and was appointed as Senior Independent Director on 12 February 2013. He is also Chairman of the Company’s Nominating Committee as well as a member of the Audit and Risk Management and Remuneration Committees.

Datuk Izzet holds a Bachelor of Arts in Actuarial Studies from Macquarie University, Sydney and a Masters in Business Administration from Cranfield Institute of Technology, United Kingdom. In his early career, Datuk Izzet served in several local and international companies including American Express, Seccolor (M) Industries, Kassim Chan & Co and Hymans Robertson & Co, Consulting Actuaries, London.

Datuk Izzet joined the Sapura Group as General Manager of Corporate Planning in 1992. He was part of the team to establish Sapura Digital Sdn Bhd, one of the pioneer operators of digital cellular operators in the country. In 1994, he became the CEO of Sapura Digital Sdn Bhd and was subsequently appointed to lead Sapura Energy Group in 1997. He was appointed CEO of SapuraCrest Petroleum Berhad, (now part of SapuraKencana Petroleum Berhad Group) in July 2003 pursuant to the acquisition of Crest Petroleum Berhad by Sapura Technology Bhd from Renong Berhad.

Datuk Izzet is currently the Group Managing Director of Perisai Petroleum Teknologi Bhd, a company listed on the Main Market of Bursa Malaysia Securities Berhad. He also holds directorships in various private companies.

Datin Sunita Mei-Lin Rajakumar Non-Executive Director

Datin Sunita Mei-Lin Rajakumar, a Malaysian aged 45, was appointed to the Board on 14 December 2010. She is also Chairperson of the Company’s Audit and Risk Management Committee as well as a member of the Nominating and Remuneration Committees.

Datin Sunita graduated with a Bachelor of Law (Honours) from the University of Bristol, UK. She qualified as a Member of the Institute of Chartered Accountants (England & Wales) in 1994.

Datin Sunita commenced work as an Assistant Manager at Ernst & Young (London) in 1990 under their Audit and Insolvency Division. In 1994, she joined RHB Sakura Merchant Bankers Berhad's Corporate Finance Department.

Datin Sunita became a Consultant for MIMOS Berhad (MIMOS) in 2000 where she advised MIMOS on the structuring of a multi-million dollar venture capital fund focused on foreign technology-related portfolio companies and the documentation required for the establishment of the fund. When the Encipta Limited venture capital fund was established in 2002, as a wholly owned subsidiary of MIMOS, her company, Artisan Encipta Ltd (Artisan Encipta) was mandated to independently manage the venture fund for MIMOS until 2008.

Since 2005, she has also been the Director and owner of Surprise Voice Sdn Bhd, the Executive Producer of Malaysia's first opera which premiered in March 2006.

Datin Sunita is presently the Principal and Director at Artisan Encipta, a position that she has held since 2002. It is now an organisation which provides consulting services on monitoring and improving national innovation ecosystems. Through Artisan Encipta, she was appointed an Independent Consultant for the King Abdul Aziz City for Science and Technology, based in Riyadh, Kingdom of Saudi Arabia. Recently, she also advised a prominent philanthropist on the impact assessment and governance issues arising from his charitable activities.

Presently, Datin Sunita serves as a trustee of the following charity foundations: Yayasan Seni, Yayasan myNadi, Hai-O Foundation at Hai-O Enterprise Berhad and Yayasan Usman Awang. She is also the chairperson of the Audit Committee at Hai-O Enterprise Berhad and holds directorships in Hai-O Enterprise Berhad and Caring Pharmacy Group Berhad (as Chair of the Board of Directors).

Roushan Arumugam Non-Executive Director

Roushan Arumugam, a Malaysian aged 42, was appointed to the Board on 25 July 2011. He is also Chairman of the Company's Remuneration Committee as well as a member of the Nominating Committee.

Roushan holds a MA in English Language and Literature from St. Catherine's College, Oxford University, United Kingdom; a Masters in Business Administration (MBA) from Imperial College Business School, Imperial College, University of London, United Kingdom; and a MA in Law from the University of Bristol, United Kingdom.

Roushan commenced work in 1995 as a Consultant at Price Waterhouse, London. In 1997, he joined Caspian Securities Limited as an Analyst, Emerging Markets Equity Research. After completing an MBA, Roushan joined Deutsche Bank A.G. London in 1999 as an Associate with its Investment Banking Division. In 2001, he moved to Malaysia to take up the position of Manager in Debt Capital Markets Division at Nomura Advisory Services Sdn. Bhd.

Since September 2005, Roushan has been an Investment Consultant to the Arumugam Family Office. He also manages Littleton Holdings Pte Ltd, an investment vehicle. Currently, Roushan serves as a board member of South Pickenham Estate Company Limited, Pneumacare Limited and Sri Inderajaya Holdings Sdn Bhd amongst other private companies.

He is also a Domus Fellow of St. Catherine's College, University of Oxford and a Trustee of the East West Trust at St. Catherine's College.

Tay Chin Kwang — Non-Executive Director

Tay Chin Kwang, a Singaporean aged 48, was appointed to the Board on 14 June 2012. He is a member of the Company's Audit and Risk Management Committee.

Chin Kwang graduated with a Bachelor of Accountancy from the National University of Singapore. He is a Certified Public Accountant and is a fellow member of the Institute of Singapore Chartered Accountants.

Chin Kwang is an advisor overseeing strategic partnerships and joint ventures with Ezra Holdings Limited, a leading offshore contractor and provider of integrated offshore solutions for the oil and gas industry, listed on the Singapore Exchange. Prior to this, he was Ezra Holdings Limited's Group Finance Director and Executive Director. He is also a director of various companies in Singapore, Thailand, Norway and Nigeria.

Chin Kwang started his career with Ernst & Young in Singapore and currently has over 24 years of experience in various accounting, finance management and business advisory functions across a broad spectrum of industries.

Sara Murtadha Jaffar Sulaiman — Non-Executive Director

Sara Murtadha Jaffar Sulaiman, an Omani national.

Sara graduated with a BA in Economics from Yale University in 1999 and subsequently with an MPhil in Economics from the University of Cambridge in 2000. She is a member of the Chartered Institute of Management Accounts.

Sara started her career in 2000 working for Petroleum Development Oman in Muscat and subsequently Shell Chemicals in the United Kingdom in a variety of finance and planning roles, where she completed her accountancy training. In 2006 she joined KPMG's Energy and Natural Resource corporate finance team in London where she was involved in a number of project finance and merger & acquisition transactions in the oil and gas, renewables and power markets. In 2008, Sara joined Simmons and Company International, a specialist energy investment bank, where she advised on a number of M&A transactions within oilfield services.

Sara is currently an Investment Manager at Arle Capital Partners, an energy focused, London based private equity firm.

Executive Management

In addition to Kenneth Pereira, the executive management team is comprised of:

Mark John Paton — Chief Business Development Officer

Mark John Paton, a British and Australian citizen aged 54, holds a Bachelor of Science (Honours) degree in Chemical Engineering from the University of Leeds, United Kingdom (UK).

Mark has 33 years' experience in the oil and gas industry, both in the services, and exploration and production sectors. He began his career with BP Exploration in 1980, as a Production and Commissioning Engineer before taking on other roles managing advanced production technology research projects, leading field development activities and assisting in the development of BP's corporate plans and strategy.

In 1989, Mark joined BHP Petroleum and held positions including as Well Services Supervisor, Production Manager and thereafter, as General Manager for BHP Petroleum's Northern Australia Operations. His responsibilities included drilling, well completion, overseeing production from three FPSO production facilities and the management of the Darwin office and logistics base.

In 1997, Mark founded an oil and gas service company, Upstream Petroleum, with a colleague from BHP Petroleum. Upstream Petroleum became the dominant provider of operations, maintenance services and marginal field development solutions to the Australian oil and gas industry. The company grew rapidly to employ over 400 employees with offices in Darwin, Perth, Melbourne and Brisbane and an oil and gas service and logistics centre in Darwin.

In 2007, subsequent to the trade sale of Upstream Petroleum to the AGR Group ASA of Norway for a headline price of AUD $85 million, AGR Group sought Mark's assistance to establish the Company's office in Kuala Lumpur, a first step by the Company into the South East Asia region. Mark served as AGR's Managing Director in Asia Pacific for two years before returning to Australia as an independent consultant in 2009.

After two years of independent consultancy work, in February 2011, Mark joined ASX-listed Cue Energy Resource Ltd as Chief Executive Officer where he remained until he joined Hibiscus Petroleum in March 2013.

Stephen Dechant — Chief Development Officer

Stephen Dechant, an American aged 56, graduated with a Bachelor of Science degree in Civil Engineering in 1981 from Kansas State University, Manhattan, Kansas.

Steve has over 30 years' experience in the oil and gas industry in a career dedicated to managing large offshore projects globally including Brazil, Nigeria, Angola, Australia, Gulf of Mexico and Malaysia. For the past 16 years, he has been involved in the management of highly complex, capital intensive deepwater projects.

His expertise includes strong leadership skills with a proven ability to assemble very strong management teams, overall project execution planning, project controls, contracting strategy, interface management and execution of both conventional and fast-track projects.

A recent highlight was Steve's senior project management role on the Kikeh Project, the first deepwater project in Malaysia. Steve joined the Kikeh Project shortly after the Kikeh discovery and led all phases of the USD2 billion development which was completed in less than 5 years from discovery.

Steve is also a director of Carnarvon Hibiscus Pty Ltd and Althea Corporation Limited.

Vincent Jacob Lee — Chief Financial Officer

Vincent Jacob Lee, a Malaysian aged 41, is a Fellow Member of the Association of Chartered Certified Accountants, United Kingdom since 2007, having completed his professional qualification in 1997. Vincent has over 17 years of working experience and has extensive knowledge and experience covering areas of accounting and reporting, financial management, financial due diligence, Enterprise Wide Risk Management, audit and assurance related type work, completion audits, upstream oil & gas accounting, and group wide restructuring.

His career started at PricewaterhouseCoopers (then called Price Waterhouse) in 1998, with their audit/assurance division. Vincent was focused mainly on their energy clients. He was involved in numerous audits/assurance work involving large companies across diverse industries. Whilst on secondment to the PricewaterhouseCoopers London office, he worked on the UK audits on a large oil major, evaluated cross border tax efficiencies and large EURO Bond offerings for his client. Vincent also conducted technical presentations and public courses on International Financial Reporting Standards, both locally and internationally, including a public course in Dubai on “IFRS in the Oil & Gas Industry”.

Vincent joined Mubadala Petroleum Malaysia in 2010 where he was tasked to head the finance division. He was responsible for setting up the financial controls, governance, overall risk management and compliance with PSC financial requirements for the Malaysian operations. From 2012 to 2014, in addition to Mubadala Petroleum Malaysia, Vincent also oversaw the finance function for Mubadala Petroleum Vietnam.

Vincent joined Hibiscus Petroleum Berhad on 1 April 2015.

Uday Jayaram — Head of Corporate Planning and IR

B.Sc (Honours) in Economics majoring in Accounting and Finance, London School of Economics, United Kingdom. Trained and qualified Chartered Accountant with the Institute of Chartered Accountants of England and Wales.

21 years of experience covering the fields of audit, management consultancy, equities research, institutional sales, capital markets and stock exchange business.

Uday began his career training in audit at Ernst & Young, London within the banking and finance division. He was involved in auditing several large public limited companies including HSBC Bank, British Airways, ABB Group and IKEA. Additionally, as a special project for the World Bank, Uday worked in Kazakhstan undertaking a diagnostic study of its banks.

In 1995, Uday joined Deutsche Morgan Grenfell, Kuala Lumpur as an equity analyst and subsequently moved to CIMB Bank where he helped build out the group’s institutional research presence as a senior analyst. In 1999, he joined ING Barings and became Head of Research in 2003. By then, he was a rated analyst and had covered most sectors in Malaysia including banks, utilities, telecommunications, and plantations. In 2005, following the takeover of ING’s broking business in Asia by Australia’s Macquarie Bank, Uday spearheaded the investment bank’s initiative to be awarded one of five foreign broker’s licenses in Malaysia. He became Head of Equity and Division Director of Macquarie Capital Securities building a business with a recognised research and sales presence amongst institutional funds both domestically and globally.

In 2010, Uday joined Bursa Securities as Global Head of Securities Markets responsible for developing the equities markets business of the exchange covering areas such as issuer, investor, product and infrastructure development. Whilst at Bursa Securities, he built strong relationships with regional and global exchanges and furthered efforts to attract greater retail and institutional flows. Uday led the ASEAN Exchanges initiative and was member of Bursa’s Market Participants Committee and Chairman of the FTSEBursa Index Advisory Committee.

Ainul Azhar Ainul Jamal — Executive Director (HIREX)

Jamal, a Malaysian aged 56, holds a B.Sc in Electrical Engineering, University of Sussex, United Kingdom. He attended the Daniels Business School at University of Denver, Colorado and the Institute for Management Development, Lausanne, Switzerland.

Jamal has 30 years' oil & gas experience with Schlumberger working at many worldwide locations, with assignments in both the oil field and technology business units. Jamal joined Schlumberger Oilfield Services in 1984 as a Wireline Field Engineer and worked in Australia, New Zealand and Indonesia. From 1996 until 2004, he held various marketing and management positions in a variety of countries around the world. From 2002 until 2004, Jamal was the Managing Director of Schlumberger Oilfield Services, South East Asia based in Kuala Lumpur.

In August 2004, Jamal was transferred to London, UK to serve as Schlumberger's Director of Communications (Internal & Marketing) and in 2005, Jamal became Director of Personnel of WesternGeco, a Schlumberger company. After serving 3 years in this role, Jamal was posted as the Group Human Resource Director for the Reservoir Management Group based in Gatwick, UK before his arrival at Schlumberger's Technology Hub in Kuala Lumpur, in August 2009 as Vice-President, Global Accounts, Asia. In 2010, Jamal was appointed as the Chairman of Schlumberger Group of Companies, Asia Pacific.

Jamal had previously served as Board member and Treasurer of the Schlumberger Foundation and also as council member of Petronas INSTEP Academic Council. Jamal is currently a member of the Institute of Electrical & Electronics Engineers (UK), the Malaysian Institute of Electrical Engineers (Malaysia) and the Society of Petroleum Engineers. He is also a council member of the Universiti Teknologi Petronas Student Advisory Council and sits on the board of International Conference and Exhibition Professionals (iCEP).

Jamal joined HIREX on 1 July 2013.

Dr Pascal Josephus Petronella Hos Chief Operating Officer (HIREX)

Dr Pascal Josephus Petronella Hos, a Dutch national aged 42 holds a Bachelor of Science degree in Mechanical Engineering and a PhD in Mechanical Engineering, from Rice University, Texas, USA.

Dr Pascal has more than 11 years' experience in reservoir engineering, production technology and rock mechanics in major local and foreign companies. He is also experienced in project management, well and reservoir management, reserves reporting, field development planning and project execution. Dr Pascal started his career in 1995 as a Wireline Research Engineer in Schlumberger Sugar Land Technology Center, Houston, USA, where he developed a statistical data analysis software for a new multi-phase fluid velocity wireline logging tool.

In 1996, he worked as a PhD Researcher with the NASA Johnson Space Center, USA, where he discovered a form of heat transfer, which led to a redesign of the oxygen storage tanks used on board the space shuttles. In 2001, Dr Pascal joined Shell International EP, Netherlands, as a Reservoir Engineer/Research Project Manager, for the research, development and deployment of an in-house fractured water injection modelling tool. He also delivered training for operating unit and technology center staff.

In 2006, Dr Pascal joined Sarawak Shell Berhad (SSB) as Senior Reservoir Engineer under the Sabah Inboard Reservoir Management team, where he was in charge of reservoir management for the Barton and St. Joseph fields. During his time in SSB, he also held various other positions namely the Subsurface Team Lead, Water Flood Manager, and was appointed as the regional expert to further standardise water flooding developments and operational design across the Asia-Pacific region. He was involved in key projects such as the St. Joseph Redevelopment project, Barton Water Injection Redevelopment Project, and the Gumusut-Kakap and Malikai projects in Malaysia.

Dr Pascal also sits on the board of Dahan Petroleum Limited.

Joyce Theresa Sunita Vasudevan VP Strategy Development

Joyce Theresa Sunita Vasudevan, a Malaysian aged 45, graduated with a Bachelor of Economics majoring in Accounting, from LaTrobe University, Melbourne, Australia. She is a member of the Australian Society of Certified Practising Accountants and the Malaysian Institute of Accountants.

Joyce has more than 23 years' experience in various areas of audit, corporate finance and finance. She started her career as an auditor with Ernst & Young in 1989 and after almost 5 years in audit, Joyce worked in the Corporate Finance department at two investment banks, Malaysian International Merchant Bankers Berhad in 1996 and RHB Sakura Merchant Bankers Berhad from 1997 to 2000. She was involved in numerous projects for government-linked companies and public listed companies including acquisitions, initial public offers, corporate restructurings, equity issuances and valuation exercises.

In 2000, Joyce joined Carlsberg Brewery Malaysia Berhad, where she headed the Business Analysis & Planning Department and was tasked with the set-up of the new department to drive business plans, formulate sales, marketing, production and competitive business models to aid in management decisions, evaluate prospective investments and develop a company-wide balanced scorecard system.

In 2006, she joined SapuraCrest Petroleum Berhad, where she headed the Strategic & Operations Planning Unit of the Chief Operating Officer's (COO) Office, and was responsible for the development of various systems including management reporting, project monitoring, key performance indicators and key processes. She also assisted the COO in driving a Group-wide reorganisation of its operations.

Joyce joined the Company on 1 January 2011 and currently sits on the boards of Hibiscus Upstream Sdn Bhd, Orient Hibiscus Sdn Bhd, Oceania Hibiscus Sdn Bhd, Hibiscus Oilfield Services Limited, Gulf Hibiscus Limited, Carnarvon Hibiscus Pty Ltd, Lime Petroleum Limited, Zubara Petroleum Limited and Baqal Petroleum Limited.

Lim Kock Hooi Head of Commercial

Lim Kock Hooi, a Malaysian aged 58, holds a Bachelor of Science (Honours) degree in Applied Geology, University of Malaya. He started his career with PETRONAS in 1981 where he practised as a petroleum geologist before retraining as a lawyer with a LLB(Hons) from the University of London in 1988. Lim then became an in-house legal counsel with PETRONAS and was the Senior Legal Counsel for E & P when he left in 1996 to practise at the Kuala Lumpur-based law firm of Azman, Davidson & Co. He was the managing partner of the firm from 2009 until 2012 when he left to join the management team of Caelus Energy Asia, a US-based E & P start-up, as the Senior Vice President, Legal for the Asia-Pacific region.

Lim has over 25 years' experience in oil and gas law practice both as in-house counsel and as advocate & solicitor whereby he has dealt with projects and assets spanning the entire value chain from upstream concessions through exploration, development and production projects covering areas in Malaysia, Indonesia, Thailand, Vietnam, the Philippines, Cambodia, Algeria and Sudan, and midstream crude/gas sales, petrochemical and refining projects to downstream distribution & retailing in Malaysia.

His practice experience includes both project documentation, and project claims & disputes resolution. Lim is a Fellow of the London-based Chartered Institute of Arbitrators. Other ancillary experiences include capital market and private equity financing.

Lim sits on the board of China Automobile Parts Holdings Limited which is listed on the Main Board of Bursa Malaysia.

Lim joined Hibiscus Petroleum Berhad on 1 October 2014.

Azleen Rosemy Ahmad GM, Corporate Finance

Azleen Rosemy Ahmad, a Malaysian aged 43, holds a Bachelor of Science degree in Actuarial Science and Finance from the Wharton Business School, University of Pennsylvania, USA, and holds a Masters in Business Administration from the University of Nottingham.

Azleen has 21 years' experience in various areas of corporate finance, finance and general management. She began her career as a management consultant with PricewaterhouseCoopers in 1992 before joining the Corporate Finance Department of RHB Sakura Merchant Bankers Berhad in 1995. During her career as management consultant and corporate adviser, she was involved in numerous projects for government agencies and public listed companies including privatisation exercises, local and foreign mergers and acquisition exercises, valuation exercises, initial public offerings, rights issues and mandatory general offers for both local and foreign companies.

In 2001, she assumed the post of Finance & Administration Manager of RCM Engineering & Services Sdn Bhd. Six years later, she joined SapuraCrest Petroleum Berhad (SapuraCrest) in the Strategic & Operations Planning Unit, where she was part of the team to implement the operational reorganisation of SapuraCrest Group's Offshore Construction business, to develop & monitor the financial performance indicators of the business units and to develop & monitor the key performance indicators of Directors/ Heads of the business units. She also led the team for the cost optimisation exercise of the SapuraCrest Group.

David Jayakumar Richards Head of Geoscience / Geology

David Jayakumar Richards, a Malaysian aged 50, graduated with a Bachelor of Science (Hons) degree in Earth Science from Universiti Kebangsaan Malaysia (National University of Malaysia).

David has 25 years of experience as a petroleum geoscientist in the exploration, development, and production and planning phases of the oil and gas industry. He started work as a geologist in 1989 with Sun Oil Far East Malaysia Inc. performing acreage evaluations in Pearl River (China), Taranaki (New Zealand), Potwar (Pakistan), Godavari (India) and Thai Basins before moving to ExxonMobil Exploration & Production Malaysia Inc. where he worked for 15 years in the exploration, development, production and planning segments. From 2006 to 2010, he was involved in the exploration and development of gas resources for Carigali-Hess Operating Company Sdn Bhd in the jointly operated area between Malaysia and Thailand. His position prior to joining Hibiscus Petroleum was as Senior Geologist with Newfield Sarawak Malaysia Inc.

He has been involved in providing planning, mapping, geo-modelling, resource/reserve assessments, geologic risk evaluation, seismic interpretation and evaluation, and operations monitoring of drilling and completion of field operations. Additionally, he has experience in integrating evaluations of various seismic data in combination with sequence stratigraphy, fault analysis, reservoir pressure, RFT /MDT sample and petrophysics in geoscientific interpretation.

Devarajan Indran Head of Petroleum Engineering

Bachelor Degree in Petroleum Engineering, Universiti Teknologi Malaysia

23 years' of experience in the upstream oil and gas industry with specific expertise in Production Technology and Production Optimisation

Dev has worked for Petronas Carigali, Shell, PTTEP and Petrofac prior to joining Hibiscus Petroleum. He has worked in multiple oil and gas fields around the world including in Malaysia, China, Thailand and Vietnam. During his career, he has held various positions with increasing level of responsibility and has gained a wide range of experience in Well Testing/DST, Workovers, Production Technology and Reservoir Engineering. His expertise includes Well Completion Design, Artificial Lift Selection & Optimsation, Sand Control, Waterflooding and Production Monitoring/Optimisation. He also has very strong mentoring and leadership skills.

Dev was recently the Subsurface Team Leader for Petrofac's Berantai Field in PM-309, offshore Peninsular Malaysia which is the first Risk Service Contract (RSC) Project in Malaysia. The marginal field was successfully brought onstream in October 2012 (gas) and January 2013 (oil), with both gas and oil production being achieved in a fast track manner and within the budgeted cost.

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Tables

Rex Technologies

In addition to the traditional explorationists tools, Hibiscus also has access to Rex Technologies' ("RT's") proprietary cutting edge exploration tools; these are summarised in Table 36 and described in more detail in this section.

Table 36 – Rex Technologies

Technology	Summary
Rex Virtual Drilling	RT's premier technology. An algorithmic direct hydrocarbon indicator that can identify differing liquids trapped in the sub surface through analysis of seismic data, thereby significantly de-risking prospects. Initial tests have proven the efficacy of the technology (~85% CoS_T) when used in conjunction with traditional seismic interpretations, in comparison with traditional seismic interpretations alone (~12% COS_T). RVD has been successfully applied both in its recent Omani drilling campaign, which opened up a new hydrocarbon province offshore Oman in the Masirah Trough. RVD has also provided the basis for the withdrawal from a number of wells, which were subsequently found to contain no hydrocarbons. Provides the Company with a key differentiating factor in the competition for upstream assets.
Rex Gravity	Rex Gravity integrates a number of separate data channels such as sea height measurement along with the gravity measurements to provide a better resolution of variation in gravity. It is a wide area tool, used to identify areas of potential interest ahead of undertaking a broad spaced 2D or 3D seismic survey.
Rex Seepage	Utilising satellite imaging technology, Rex Seepage is able to detect offshore seepages from potential hydrocarbon reservoirs. While not definitive in itself, when used in conjunction with Rex Gravity, it may enable better investment decisions to be made.

Source: Company & SPA data

Hibiscus' access to the technology has been effected by the formation of a JV (Hirex Petroleum) with Rex International in March 2013; the agreement covers an initial term of 5 years, but has provision for extension. However, the agreement only covers a select number of countries in Asia and Oceania (Figure 76). In other countries, such as Norway, Oman and the UAE, Hibiscus is able call on RT's technologies though its interest in the Lime Petroleum JV.

Figure 76 – HiRex Petroleum JV Coverage

Map illustrating the HiRex Petroleum coverage countries

Source: Company

Valuation of E&P Companies

General Approach

Valuation of E&P assets reflect not only the value of the cash flow from assets that have reserves or contingent resources assigned to them, but the market also assigns an "option" value to exploration assets particularly when contingent or prospective resources have been defined by drilling, seismic interpretation and other accepted technologies.

Overall, company net asset valuations are made up of the sum of three distinct parts:

1. **Core NAV:** "Core" reserves relating to assets already in production or sanctioned for development: these are usually represented as reserves and these can be developed or undeveloped;

2. **Development & Appraisal NAV:** those discovered assets that have been appraised and are awaiting development sanction or discoveries that are awaiting further appraisal: these are usually represented as contingent resources; and

3. **Exploration NAV:** the valuation of "Upside" reserve and resource potential over and above that already included in the reserve or contingent resources category where the asset can be at the exploration, appraisal or development stage: last category captures the value of exploration assets that are deemed to be prospective resources.

The risk adjusted net asset value ("Risked NAV") is calculated as the total of the Core NAV plus the Development & Appraisal NAV adjusted for chance of success plus the Exploration NAV adjusted for the chance of success.

Chance of Success

The total chance of success (“CoS_T”) for (ii) a Development & Appraisal asset or (iii) an Exploration asset (above), is a function of two distinct and separate risk elements:

Geological Chance of Success (“CoS_G”): which measures the four elements required to have an accumulation of oil or gas, namely, Source, Seal, Trap and Reservoir; and

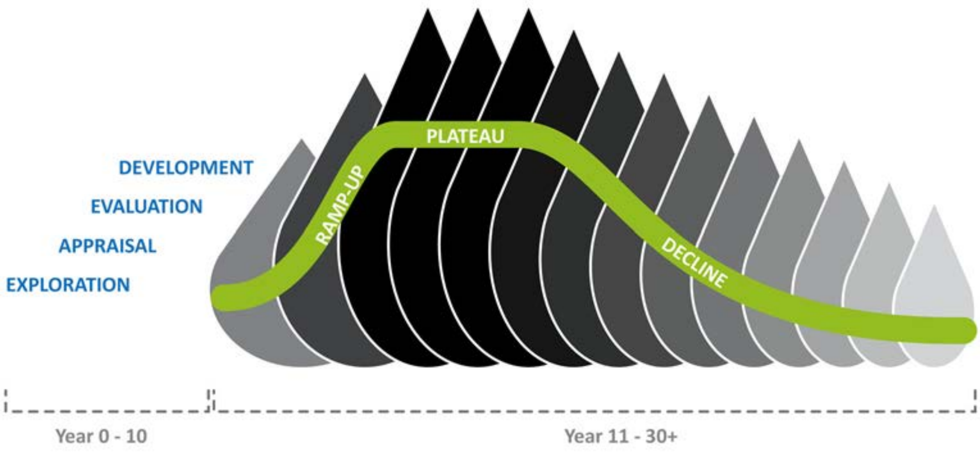
Technical-to-Commercial Chance of Success (“CoS_C”): which reflects the likelihood that once found, the accumulation proves commercial (sometimes CoS_C is further broken down into two elements: Chance of Economic Success and Chance of Threshold Economic Field Size).

Production Profiles and Phasing Assumptions

For DCF valuation modelling of each exploration, development and appraisal asset in this Valuation Report, SPA adopted a generalised capital investment and production profile as described below (Figure 77).

Figure 77 – Generalised Profile

Investment and Production Profile (illustrative only)



Source: SPA

Expected Monetary Value

SPA makes further adjustments to (ii) Development and Appraisal assets or (iii) an Exploration assets (see above) that are not in production by applying an Expected monetary value (“EMV”) methodology.

We believe that EMV is an appropriate methodology as it reconciles the impact of a successful drilling campaign, against the probability of a success and the cost of getting to a position at which the project’s probability of success exceeds the probability of failure, adjusted for any systemic errors.

EMV returns a value of an asset based on the collective cost and probability outcomes for a range of factors. This values an asset (“NAV_D”) as a risk adjustment to its success-based net present value discounted at an appropriate discount rate (subscript “D”) (“NPV_D”), corrected for the total chance of success (CoS_T) and the risk capital (“C_R”) required to get the asset to the “go / no go” decision (see below).

$$NAV_{(D)} = \left(NPV_{(D)} \times CoS_T\right) - \left(C_R \times (1 - CoS_T)\right)$$

While the risk capital varies by asset as a function of drilling location, depth and expected subsurface conditions, the risk factors vary according to the stage of development.

Country Brief Supplement

Table 37 – S&P Credit Ratings

Grading	Rating	Description
Investment Grade	AAA	Extremely strong capacity to meet financial commitments. Highest rating
	AA	Very strong capacity to meet financial commitments
	A	Strong capacity to meet financial commitments, but somewhat susceptible to adverse economic conditions and changes in circumstances
	BBB	Adequate capacity to meet financial commitments, but more subject to adverse economic conditions
	BBB-	Considered lowest investment grade by market participants
Speculative Grade	BB+	Considered highest speculative grade by market participants
	BB	Less vulnerable in the near-term but faces major on-going uncertainties to adverse business, financial and economic conditions
	B	More vulnerable to adverse business, financial and economic conditions but currently has the capacity to meet financial commitments
	CCC	Currently vulnerable and dependent on favourable business, financial and economic conditions to meet financial commitments
	CC	Currently highly vulnerable
	C	A bankruptcy petition has been filed or similar action taken, but payments of financial commitments are continued
	D	Payments default on financial commitments

Source: Standard & Poor's
NOTE: Ratings from 'AA' to 'CCC' may be modified by the addition of a plus (+) or minus (-) sign to show relative standing within the major rating categories.

Table 38 – Moody Credit Ratings

Rating	Description
Aaa	Issuers or issues rated Aaa demonstrate the strongest creditworthiness relative to other domestic issuers
Aa	Issuers or issues rated Aa demonstrate very strong creditworthiness relative to other domestic issuers
A	Issuers or issues rated A present above-average creditworthiness relative to other domestic issuers
Baa	Issuers or issues rated Baa represent average creditworthiness relative to other domestic issuers
Ba	Issuers or issues rated Ba demonstrate below-average creditworthiness relative to other domestic issuers
B	Issuers or issues rated B demonstrate weak creditworthiness relative to other domestic issuers
Caa	Issuers or issues rated Caa are speculative and demonstrate very weak creditworthiness relative to other domestic issuers
Ca	Issuers or issues rated Ca are highly speculative and demonstrate extremely weak creditworthiness relative to other domestic issuers
C	Issuers or issues rated C are extremely speculative and demonstrate the weakest creditworthiness relative to other domestic issuers
Numerical Suffix	Moody's applies numerical modifiers 1, 2, and 3 in each generic rating classification from Aa to Caa. The modifier 1 indicates that the obligation ranks in the higher end of its generic rating category; the modifier 2 indicates a mid-range ranking; and the modifier 3 indicates a ranking in the lower end of that generic rating

Source: Moody's & SP Angel data

Heritage Foundation's Measurement of Economic Freedom

Introduction

The Heritage's index attempts to take a comprehensive view of the country in question, the overall assessment of a country's economic freedom is derived by scoring it on the basis of 10 separate areas of economic freedom. Some of the measured aspects of economic freedom are concerned with a country's interactions with the rest of the world, such as the extent of an economy's openness to global investment or trade. Most, however, focus on policies within a country, assessing the liberty of individuals to use their labour or finances without undue restraint and government interference.

Each of the economic freedoms plays a vital role in developing and sustaining personal and national prosperity. They are not mutually exclusive, however, and progress in one area is often likely to reinforce or even inspire progress in another. Similarly, repressed economic freedom in one area – respect for property rights may make it much more difficult to achieve high levels of freedom in other categories.

Rule of Law

Property Rights

The ability to accumulate private property and wealth is understood to be a central motivating force for workers and investors in a market economy. The recognition of private property rights, with sufficient rule of law to protect them, is a vital feature of a fully functioning market economy. Secure property rights give citizens the confidence to undertake entrepreneurial activity, save their income, and make long-term plans because they know that their income, savings, and property (both real and intellectual) are safe from unfair expropriation or theft.

The protection of private property requires an effective and honest judicial system that is available to all, equally and without discrimination. The independence, transparency, and effectiveness of the judicial system have proved to be key determinants of a country's prospects for long-term economic growth. Such a system is also vital to the maintenance of peace and security and the protection of human rights.

A key aspect of property rights protection is the enforcement of contracts. The voluntary undertaking of contractual obligations is the foundation of the market system and the basis for economic specialisation, gains from commercial exchange, and trade among nations. Even-handed government enforcement of private contracts is essential to ensuring equity and integrity in the marketplace.

Freedom from Corruption

Corruption is defined as dishonesty or decay. In the context of governance, it can be defined as the failure of integrity in the system, a distortion by which individuals are able to gain personally at the expense of the whole. Political corruption manifests itself in many forms such as bribery, extortion, nepotism, cronyism, patronage, embezzlement, and (most commonly) graft, whereby public officials steal or profit illegitimately from public funds.

Corruption can infect all parts of an economy; there is a direct relationship between the extent of government regulation or other government intervention in economic activity and the amount of corruption. Almost any government regulation can provide an opportunity for bribery or graft. In addition, a government regulation or restriction in one area may create an informal market in another. For example, a country with high barriers to trade may have laws that protect its domestic market and prevent the import of foreign goods, but these barriers create incentives for smuggling and a black market for the restricted products.

Transparency is the best weapon against corruption. Openness in regulatory procedures and processes can promote equitable treatment and greater regulatory efficiency and speed.

Limited Government

Fiscal Freedom

Fiscal freedom is a direct measure of the extent to which individuals and businesses are permitted by government to keep and control their income and wealth for their own benefit and use. A government can impose fiscal burdens on economic activity through taxation, but it also does so when it incurs debt that ultimately must be paid off through taxation.

The marginal tax rate confronting an individual is, in effect, the government's cut of the profit from his or her next unit of work or engagement in a new entrepreneurial venture; whatever remains after the tax is subtracted is the individual's actual reward for the effort. The higher the government's cut, the lower the individual's reward—and the lower the incentive to undertake the work at all. Higher tax rates interfere with the ability of individuals and firms to pursue their goals in the marketplace and reduce, on average, their willingness to work or invest.

While individual and corporate income tax rates are important to economic freedom, they are not a comprehensive measure of the tax burden. Governments impose many other indirect taxes, including payroll, sales, and excise taxes; tariffs; and the value-added tax ("VAT"). In the Index of Economic Freedom, the burden of these taxes is captured by measuring the overall tax burden from all forms of taxation as a percentage of total GDP.

Government Spending

The cost of excessive government is a central issue in economic freedom, both in terms of generating revenue (see fiscal freedom) and in terms of spending. Some government spending, such as providing infrastructure or funding research or even improvements in human capital, may be thought of as investments. There are public goods, the benefits of which accrue broadly to society in ways that markets cannot appropriately price. All government spending must eventually be financed by higher taxation, however, entails an opportunity cost equal to the value of the private consumption or investment that would have occurred had the resources involved been left in the private sector.

In other words, excessive government spending runs a great risk of crowding out private economic activity. Even if an economy achieves fast growth through heavy government expenditure, such economic expansion tends to be only short-lived, distorting allocation of resources and private investment incentives. Even worse, a government's insulation from market discipline often leads to bureaucracy, lower productivity, inefficiency, and mounting debt that imposes an even greater burden on future generations.

As many have experienced in recent years, high levels of public debt accumulated by irresponsible government spending undermine economic freedom and stifle growth.

Regulatory Efficiency

Business Freedom

Business freedom is about an individual's right to establish and run an enterprise without interference from the state. Burdensome and redundant regulations are the most common barriers to the free conduct of entrepreneurial activity.

By increasing the costs of production, regulations can make it difficult for entrepreneurs to succeed in the marketplace. Although many regulations hinder business productivity and profitability, the most inhibiting to entrepreneurship are those that are associated with licensing new businesses.

In some countries, as well as many states in the United States, the procedure for obtaining a business license can be as simple as mailing in a registration form with a minimal fee. In Hong Kong, for example, obtaining a business license requires filling out a single form, and the process can be completed in a few hours. In other economies, such as India and parts of South America, the process of obtaining a business license can take much longer, involving endless trips to government offices and repeated encounters with officious and sometimes corrupt bureaucrats.

Once a business is open, government regulation may interfere with the normal decision-making or price-setting process. Interestingly, two countries with the same set of regulations can impose different regulatory burdens. If one country, for instance, applies its regulations evenly and transparently, it lowers the regulatory burden by facilitating long-term business planning. If the other applies regulations inconsistently, it raises the regulatory burden by creating an unpredictable business environment. Rigid and onerous bankruptcy procedures are also distortionary, providing a disincentive for entrepreneurs to start businesses in the first place.

Labour Freedom

The ability of individuals to work as much as they want and wherever they want is a key component of economic freedom. By the same token, the ability of businesses to contract freely for labour and dismiss redundant workers when they are no longer needed is a vital mechanism for enhancing productivity and sustaining overall economic growth. The core principle of any market is free, voluntary exchange. That is as true in the labour market as it is in the market for goods.

State intervention generates the same problems in the labour market that it produces in any other market. Government regulations take a variety of forms, including wage controls, hiring and firing restrictions, and other restrictions. In many countries, unions play an important role in regulating labour freedom and, depending on the nature of their activity, may be either a force for greater freedom or an impediment to the efficient functioning of labour markets. In general, the greater the degree of labour freedom, the lower the rate of unemployment in an economy.

Monetary Freedom

Monetary freedom, reflected in a stable currency and market-determined prices, is to an economy what free speech is to democracy. Free people need a steady and reliable currency as a medium of exchange, unit of account, and store of value. Without monetary freedom, it is difficult to create long-term value or amass capital.

The value of a country's currency is controlled largely by the monetary policy of its government. With a monetary policy that endeavours to fight inflation, maintain price stability, and preserve the nation's wealth, people can rely on market prices for the foreseeable future. Investments, savings, and other longer-term plans can be made more confidently. An inflationary policy, by contrast, confiscates wealth like an invisible tax and also distorts prices, misallocates resources, and raises the cost of doing business.

There is no single accepted theory of the right monetary policy for a free society. At one time, the gold standard enjoyed widespread support. What characterises almost all monetary theories today, however, is support for low inflation and an independent central bank. There is also widespread recognition that price controls corrupt market efficiency and lead to shortages or surpluses.

Open Markets

Trade Freedom

Trade freedom reflects an economy's openness to the import of goods and services from around the world and the citizen's ability to interact freely as buyer or seller in the international marketplace. Trade restrictions can manifest themselves in the form of tariffs, export taxes, trade quotas, or outright trade bans. However, trade restrictions also appear in more subtle ways, particularly in the form of regulatory barriers. The degree to which government hinders the free flow of foreign commerce has a direct bearing on the ability of individuals to pursue their economic goals and maximize their productivity and well-being.

Tariffs, for example, directly increase the prices that local consumers pay for foreign imports, but they also distort production incentives for local producers, causing them to produce either a good in which they lack a comparative advantage or more of a protected good than is economically efficient. This impedes overall economic efficiency and growth. In many cases, trade limitations also put advanced-technology products and services beyond the reach of local entrepreneurs, limiting their own productive development.

Investment Freedom

A free and open investment environment provides maximum entrepreneurial opportunities and incentives for expanded economic activity, greater productivity, and job creation. The benefits of such an environment flow not only to the individual companies that take the entrepreneurial risk in expectation of greater return, but also to society as a whole. An effective investment framework will be characterised by transparency and equity, supporting all types of firms rather than just large or strategically important companies, and will encourage rather than discourage innovation and competition.

Restrictions on the movement of capital, both domestic and international, undermine the efficient allocation of resources and reduce productivity, distorting economic decision-making. Restrictions on cross-border investment can limit both inflows and outflows of capital, shrinking markets and reducing opportunities for growth.

In an environment in which individuals and companies are free to choose where and how to invest, capital will flow to its best use: to the sectors and activities where it is most needed and the returns are greatest. State action to redirect the flow of capital and limit choice is an imposition on the freedom of both the investor and the person seeking capital. The more restrictions a country imposes on investment, the lower its level of entrepreneurial activity.

Financial Freedom

A transparent and open financial system ensures fairness in access to financing and promotes entrepreneurship. An open banking environment encourages competition to provide the most efficient financial intermediation between households and firms and between investors and entrepreneurs.

Through a process driven by supply and demand, markets provide real-time information on prices and immediate discipline for those who have made bad decisions. This process depends on transparency in the market and the integrity of the information being made available. An effective regulatory system, through disclosure requirements and independent auditing, ensures both.

Increasingly, the central role played by banks is being complemented by other financial services that offer alternative means for raising capital or diversifying risk. As with the banking system, the useful role for government in regulating these institutions lies in ensuring transparency; promoting disclosure of assets, liabilities, and risks; and ensuring integrity.

Banking and financial regulation by the state that goes beyond the assurance of transparency and honesty in financial markets can impede efficiency, increase the costs of financing entrepreneurial activity, and limit competition. If the government intervenes in the stock market, for instance, it contravenes the choices of millions of individuals by interfering with the pricing of capital, the most critical function of a market economy. Equity markets measure, on a continual basis, the expected profits and losses in publicly held companies. This measurement is essential in allocating capital resources to their highest-valued uses and thereby satisfying consumers' most urgent requirements.

SPE Petroleum Resources Classification Framework

Petroleum is defined as a naturally occurring mixture consisting of hydrocarbons in the gaseous, liquid, or solid phase. Petroleum may also contain non-hydrocarbons, common examples of which are carbon dioxide, nitrogen, hydrogen sulphide and sulphur. In rare cases, non-hydrocarbon content could be greater than 50%.

The term "resources" as used herein is intended to encompass all quantities of petroleum naturally occurring on or within the Earth's crust, discovered and undiscovered (recoverable and unrecoverable), plus those quantities already produced. Further, it includes all types of petroleum whether currently considered "conventional" or "unconventional." Figure 78 is a graphical representation of the SPE/WPC/AAPG/SPEE resources classification system. The system defines the major recoverable resources classes: Production, Reserves, Contingent Resources, and Prospective Resources, as well as Unrecoverable petroleum.

The "Range of Uncertainty" reflects a range of estimated quantities potentially recoverable from an accumulation by a project, while the vertical axis represents the "Chance of Commerciality," that is, the chance that the project will be developed and reach commercial producing status. Table 39 summarises the definitions that apply to the major subdivisions within the resources classification (Figure 78).

Estimated Ultimate Recovery ("EUR") is not a resources category, but a term that may be applied to any accumulation or group of accumulations (discovered or undiscovered) to define those quantities of petroleum estimated, as of a given date, to be potentially recoverable under defined technical and commercial conditions plus those quantities already produced (total of recoverable resources).

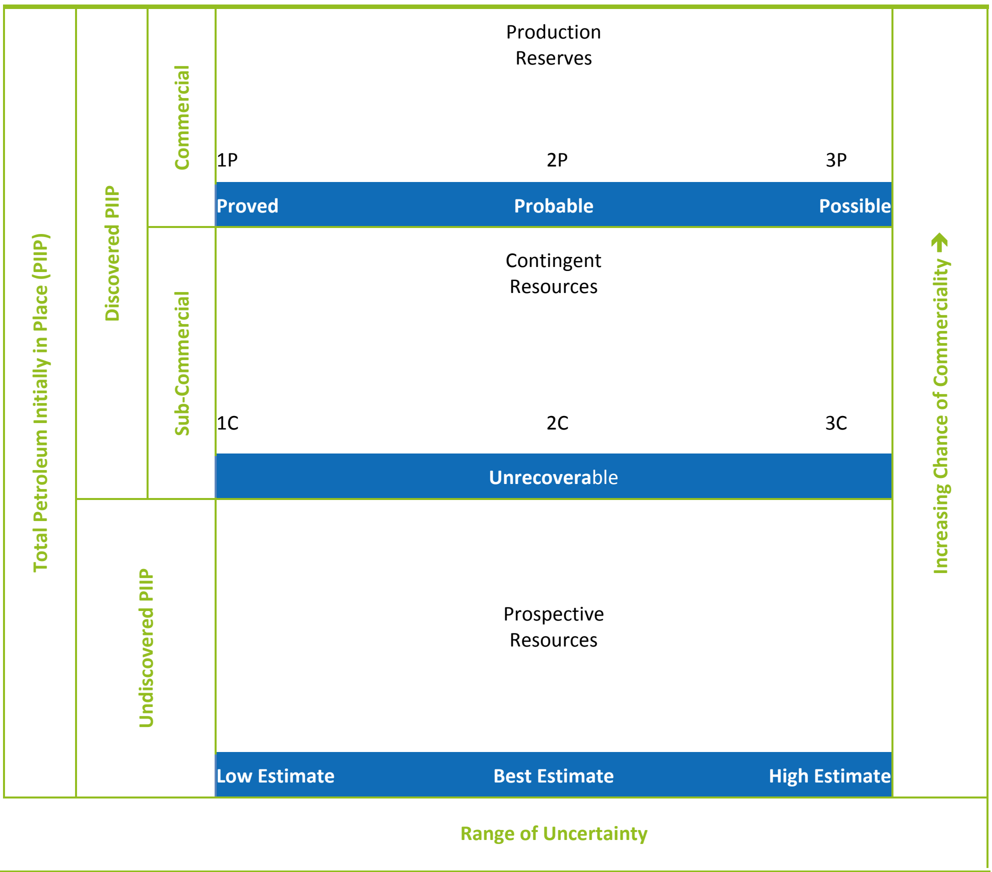
In specialised areas, such as basin potential studies, alternative terminology has been used; the total resources may be referred to as Total Resource Base or Hydrocarbon Endowment. Total recoverable or EUR may be termed Basin Potential. The sum of Reserves, Contingent Resources, and Prospective Resources may be referred to as "remaining recoverable resources." When such terms are used, it is important that each classification component of the summation also be provided. Moreover, these quantities should not be aggregated without due consideration of the varying degrees of technical and commercial risk involved with their classification.

Table 39 – Resources Classification Terms

Term	Description
Total Petroleum Initially-in-Place:	That quantity of petroleum that is estimated to exist originally in naturally occurring accumulations. It includes that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production plus those estimated quantities in accumulations yet to be discovered (equivalent to "total resources").
Discovered Petroleum Initially-in-Place:	That quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production. Production is the cumulative quantity of petroleum that has been recovered at a given date. While all recoverable resources are estimated and production is measured in terms of the sales product specifications, raw production (sales plus non-sales) quantities are also measured and required to support engineering analyses based on reservoir voidage (see Production Measurement, section 3.2). Multiple development projects may be applied to each known accumulation, and each project will recover an estimated portion of the initially-in-place quantities. The projects shall be subdivided into Commercial and Sub-Commercial, with the estimated recoverable quantities being classified as Reserves and Contingent Resources respectively, as defined below.
Reserves:	Those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves must further satisfy four criteria: they must be discovered, recoverable, commercial, and remaining (as of the evaluation date) based on the development project(s) applied. Reserves are further categorised in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterised by development and production status.
Contingent Resources:	Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations, but the applied project(s) are not yet considered mature enough for commercial development due to one or more contingencies. Contingent Resources may include, for example, projects for which there are currently no viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality. Contingent Resources are further categorised in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterised by their economic status.
Undiscovered Petroleum Initially-in-Place:	That quantity of petroleum estimated, as of a given date, to be contained within accumulations yet to be discovered.
Prospective Resources:	Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective Resources have both an associated chance of discovery and a chance of development. Prospective Resources are further subdivided in accordance with the level of certainty associated with recoverable estimates assuming their discovery and development and may be sub-classified based on project maturity.
Unrecoverable:	That portion of Discovered or Undiscovered Petroleum Initially-in-Place quantities which is estimated, as of a given date, not to be recoverable by future development projects. A portion of these quantities may become recoverable in the future as commercial circumstances change or technological developments occur; the remaining portion may never be recovered due to physical/chemical constraints represented by subsurface interaction of fluids and reservoir rocks.

Source: SPE & SP Angel

Figure 78 – Resources Classification Framework



Source: SPE & SP Angel

Range of Uncertainty

The range of uncertainty of the recoverable and/or potentially recoverable volumes may be represented by either deterministic scenarios or by a probability distribution. When the range of uncertainty is represented by a probability distribution, a low, best, and high estimate shall be provided such that:

- There should be at least a 90% probability (P_{90}) that the quantities actually recovered will equal or exceed the low estimate.
- There should be at least a 50% probability (P_{50}) that the quantities actually recovered will equal or exceed the best estimate.
- There should be at least a 10% probability (P_{10}) that the quantities actually recovered will equal or exceed the high estimate.

These definitions and guidelines are extracted from SPE PRMS, approved March 2007. The full text of the SPE PRMS Definitions and Guidelines can be viewed at:

www.spe.org/industry/docs/Petroleum_Resources_Management_System_2007.pdf

Glossary

Term	Description
1C	Denotes low estimate scenario of Contingent Resources
1P	Proved reserves
2C	Denotes best estimate scenario of Contingent Resources
2D	A group of seismic lines acquired individually, as opposed to the multiple closely spaced lines acquired together that constitute 3D seismic data
2P	Proved oil + Probable oil
3C	Denotes high estimate scenario of Contingent Resources
3D	A set of numerous closely-spaced seismic lines that provide a high spatially sampled measure of subsurface reflectivity. Typical receiver line spacing can range from 300m (1,000ft) to over 600m (2,000ft), and typical distances between shotpoints and receiver groups are 25m (82ft) (offshore and internationally) and 110ft or 220ft (34 to 67m) (onshore US, using values that are even factors of the 5,280ft in a mile)
3P	Proved oil + Probable oil + Possible oil
Albian	Geologic term covering period between 107 and 95 million years ago
Alkanes	Saturated (single bonds between the carbon atoms) hydrocarbons. Normal alkanes or paraffins have the carbons arranged in long chains, while the terms cyclic and branched alkanes describe the arrangement of carbon atoms in rings or with side chains.
Amplitude anomaly	An abrupt increase in seismic amplitude that can indicate the presence of hydrocarbons, although such anomalies can also result from processing problems, geometric or velocity focusing or changes in lithology. Amplitude anomalies that indicate the presence of hydrocarbons can result from sudden changes in acoustic impedance, such as when a gas sand underlies a shale, and in that case, the term is used synonymously with hydrocarbon indicator
API gravity	An arbitrary scale expressing the density of liquid (gravity) petroleum products devised jointly by the American Petroleum Institute and the National Bureau of Standards. Oil with the lowest specific gravity at atmospheric conditions and 70 degrees Fahrenheit has the highest API gravity. The measuring scale is calibrated in terms of degrees API. API gravity is the industry standard for expressing the specific gravity (SG) of crude oils. A high API gravity means lower specific gravity and lighter oils $$API = \frac{141.5}{SG_{(@60°F)}} - 131.5$$
Aptian	Geologic term covering period between 114 and 107 million years ago
Arbuckle	A subset of the Ordovician period
Attic Oil	Crude oil located at the top of a reservoir, above the optimal production zone. It can either be extracted via a deviated well from the original production string or spudding a new well targeting the crest of the structure
Authigenic	Generated where it is found or observed
Basin	A depression in the Earth's surface, containing the youngest section of rock in its lowest, central part
bbl	Barrel
bcf	Billion cubic feet ($1x10^9$ ft^3)
bcfpd	Billion cubic feet per day
Biomarkers	Compounds (commonly polycyclic alkanes) that have structures similar to biological molecules and are commonly diagnostic of the total organic material in a rock. Biomarkers can be used to draw inferences about the depositional environment and to track such processes as maturation, migration, and biodegradation. Typical biomarkers include sterane compounds derived from steroids in living organic matter, and the isoprenoid alkanes, pristane and phytane, derived, at least in part, from chlorophyll. The term odd/even (or even/odd) predominance refers to normal alkane chain lengths and describes the characteristics of paraffin compounds in gas chromatograms. The ratio of odd/even chain lengths can be used to estimate thermal maturity and to draw inferences about the source rock character.

Term	Description
bn	billion ($1x10^9$)
boe	Barrels of oil equivalent
boepd	Barrels of oil equivalent per day
bpd	Barrels oil per day
bpy	Barrels oil per year
Btu	British thermal unit
Cambrian	Geologic term covering period between 541 to 485 million years ago
Campanian	Geologic term covering period between 84 and 72 million years ago
Cenozoic	Geologic term covering period between 65 million years ago to the present
Chance of Success	The risk factor measuring the likelihood that a prospect being drilled will discover hydrocarbons in sufficient quantities and with a reservoir able to produce such hydrocarbons at commercial rates
Chance of Success – Commercial	The risk factor measuring the likelihood that once found, an accumulation proves commercial
Chance of Success – Geological	The risk factor measuring the four elements required to have an accumulation of oil or gas, namely, Source, Seal, Trap and Reservoir
Chance of Success – Overall	Overall chance of success, defined as a function of CoS_G and COS_C: $$CoS_T = CoS_G \times CoS_C$$
Clastic	Sediment consisting of broken fragments derived from pre-existing rocks and transported elsewhere and redeposited before forming another rock. Examples of common clastic sedimentary rocks include siliciclastic rocks such as conglomerate, sandstone, siltstone and shale. Carbonate rocks can also be broken and reworked to form clastic sedimentary rocks
CoS	Chance of Success
COS_C	Commercial Chance of Success
CoS_G	Geological Chance of Success
CoS_T	Overall Chance of Success
Cretaceous	Geologic term covering period between 145 and 65 million years ago
Darcy	A standard unit of measure of permeability. One darcy describes the permeability of a porous medium through which the passage of one cubic centimetre of fluid having one centipoise of viscosity flowing in one second under a pressure differential of one atmosphere where the porous medium has a cross-sectional area of one square centimetre and a length of one centimetre. A millidarcy (mD) is one thousandth of a darcy and is a commonly used unit for reservoir rocks
DCF	Discounted Cash Flow
Delta(ic)	An area of deposition or the deposit formed by a flowing sediment-laden current as it enters an open or standing body of water, such as a river spilling into a gulf. As a river enters a body of water, its velocity drops and its ability to carry sediment diminishes, leading to deposition. The term has origins in Greek because the shape of deltas in map view can be similar to the Greek letter delta. The shapes of deltas are subsequently modified by rivers, tides and waves. There is a characteristic coarsening upward of sediments in a delta. The three main classes of deltas are river-dominated (Mississippi River), wave-dominated (Nile River) and tide-dominated (Ganges River). Ancient deltas contain some of the largest and most productive petroleum systems.
Desmoinesian	Geologic term covering period between 308 to 306 million years ago
Devonian	Geologic term covering period between 410 and 360 million years ago
DHI	Direct Hydrocarbon Indicator
Diagenesis	All chemical, physical and biological modifications undergone by a sediment after its initial deposition
DMG	Domestic Market Gas. Gas sold to the host government, usually at a discount to the prevailing market price.

Term	Description
DMO	Domestic Market Oil. Oil sold to the host government, usually at a discount to the prevailing market price.
Downdip	Located down the slope of a dipping plane or surface. In a dipping (not flat-lying) hydrocarbon reservoir that contains gas, oil and water, the gas is updip, the gas-oil contact is downdip from the gas, and the oil-water contact is still farther downdip
Dyke	A discordant intrusive rock that is substantially wider than it is thick. Dykes are often steeply inclined or nearly vertical. The expansion of a rock's volume caused by stress and deformation
Dysaerobic	Applied to a depositional environment with 0.1–1.0 ml dissolved O_2 per litre of water
E&P	Exploration & Production
Eocene	Geologic term covering period between 54.8 and 33.7 million years ago
Epeirogenic	Refers to upheavals or depressions of land exhibiting long wavelengths and little folding apart from broad undulations
Epicontinental	Located on a continental shelf
EUR	Estimated Ultimate Recovery is a term which may be applied to an individual accumulation of any status/maturity (discovered or undiscovered). Estimated Ultimate Recovery is defined as those quantities of petroleum which are estimated, on a given date, to be potentially recoverable from an accumulation, plus those quantities already produced
Eustatic	Denoting or relating to worldwide changes in sea level, caused by the melting of ice sheets, movements of the ocean floor, sedimentation, etc.
Farm-in	The process of buying into a licence block held by another licensee by paying a proportion of the costs, normally in excess to the interest that is finally earned, e.g., earning a 15% interest on a 2:1 basis means that 30% is paid
Fault block	A section of rock separated from other rock by one or more faults
FEED	Front End Engineering and Design
Fischer Assay	A standardised laboratory test for determining the oil yield from oil shale to be Expected from a conventional shale oil extraction. A 100 gram oil shale sample crushed to <2.38 mm is heated in a small aluminum retort to 500°C (930°F) at a rate of 12°C/min (22°F/min), and held at that temperature for 40 minutes. The distilled vapors of oil, gas, and water are passed through a condenser and cooled with ice water into a graduated centrifuge tube. The oil yields achieved by other technologies are often reported as apercentage of the Fischer Assay oil yield
Fluvial	Pertaining to an environment of deposition by a river or running water. Fluvial deposits tend to be well sorted, especially in comparison with alluvial deposits, because of the relatively steady transport provided by rivers
ft^3	Cubic feet
FTP	First Tranche Petroleum: a form of Royalty payment.
G&G	Geology & Geophysics
Gas chimney	A subsurface leakage of gas from a poorly sealed hydrocarbon accumulation. The gas can cause overlying rocks to have a low seismic velocity, thereby becoming visible. Gas chimneys are visible in seismic data as areas of poor data quality or push-downs
GOR	Gas / oil ratio (mm cf/bbl)
Graben	A relatively low-standing fault block bounded by opposing normal faults. Graben (used as both singular and plural) can form in areas of rifting or extension, where normal faults are the most common type of fault. Between graben are relatively high-standing blocks called horsts. A half-graben is a downdropped block bounded by a normal fault on only one side
Horst	A relatively high-standing area formed by the movement of normal faults that dip away from each other. Horsts occur between low-standing fault blocks called graben. Horsts can form in areas of rifting or extension, where normal faults are the most abundant variety of fault
Igneous	Types of rock that are formed through the cooling and solidification of magma or lava
Jurassic	Geologic term covering period between 215 and 145 million years ago

Term	Description
Kerogen	The naturally occurring, solid, insoluble organic matter that occurs in source rocks and can yield oil upon heating. Typical organic constituents of kerogen are algae and woody plant material. Kerogens have a high molecular weight relative to bitumen, or soluble organic matter; bitumen forms from kerogen during petroleum generation. Three types of kerogen are defined by atomic hydrogen to carbon (H/C) ratio Kerogens are described as: • Type I (H/C less than 1.4), consisting of mainly algal and amorphous (but presumably algal) kerogen and highly likely to generate oil; • Type II (H/C 1.2 – 1.4), mixed terrestrial and marine source material that can generate waxy oil; and • Type III (H/C less than1.0), woody terrestrial source material that typically generates gas
kg	Kilogram
km	Kilometers
kWh	Kilowatt-hour
Lacustrine	Pertaining to an environment of deposition in lakes, or an area having lakes. Because deposition of sediment in lakes can occur slowly and in relatively calm conditions, organic-rich source rocks can form in lacustrine
lb	Pounds (avoirdupois)
Lead	Potential area where one or more accumulations are currently poorly defined and require more data acquisition and/or evaluation in order to be classified as a prospect. A lead will occur within a play
Limnic	Relating to fresh water
Lithology	The macroscopic nature of the mineral content, grain size, texture and colour of rocks
LNG	Liquefied Natural Gas, mainly methane and ethane, which has been liquefied at cryogenic temperatures
m	Thousand ($1x10^3$)
m bbl	Thousand barrels
m^3	Cubic meter
mcf	Thousand cubic feet
mD	Millidarcy. See Darcy
Mesozoic	The era with a time span from 250 million to 65 million years ago. This includes the Triassic, Jurassic and Cretaceous periods. The Earth was believed to be warmer with higher sea level and no polar ice during this era. The largest global-scale mass extinction (the Permian Extinction) was believed to occur toward the beginning of the Mesozoic Era, of which new life forms such as dinosaurs and mammals began to dominate the Earth
Metamorphic	Types of rock that are formed by the transformation of existing rock types, in a process called metamorphism, which means “change in form”
Miocene	Geologic term covering period between 23 and 5 million years ago
Mississippian	Lower Carboniferous from 359ma 318ma
mm	Million ($1x10^6$)
mm bbl	Million barrels
mm boe	Million barrels of oil equivalent
mm scfpd	Million standard cubic feet of gas per day
mya	Million years ago
NAV	Net Asset Value
$NAV_{(D)}$	Net asset value discounted at Discount Rate “D”
NGL	Natural Gas Liquids are the components of natural gas that are liquid at in field facilities, or gas-processing plants. NGLs can be classified according to their vapour pressures as low (condensate), intermediate (natural gasoline) and high (liquefied petroleum gas) vapour pressure; examples include propane, butane, pentane, hexane and heptane, but not methane and ethane, since these hydrocarbons need refrigeration to be liquefied.

Term	Description
NOC	National Oil Company
NPV	Net Present Value
NPV$_{(10)}$	Net present value discounted at 10%
Oligocene	Geologic term covering period between 33.7 and 23.8 million years ago.
OOIP	Original Oil In Place
Ordovician	Geologic term covering period between 488 and 444 million years ago
Orogeny	The process of mountain formation, especially by the upward displacement of the Earth's crust
Overburden	The material that lies above a series of economic or scientific interest. Also called waste or spoil
P&A	Plugged & Abandoned
P1 **Proven oil**	Proved reserves are those quantities of petroleum which, by analysis of geological and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under current economic conditions, operating methods, and government regulations. Proved reserves can be categorised as developed or undeveloped. If deterministic methods are used, the term reasonable certainty is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate.
P$_{10}$	The quantity that has at least 10% probability of being exceeded
P2 **Probable oil**	Probable reserves are those unproved reserves which analysis of geological and engineering data suggests are more likely than not to be recoverable. In this context, when probabilistic methods are used, there should be at least a 50% probability that the quantities actually recovered will equal or exceed the sum of estimated proved plus probable reserves.
P3 **Possible oil**	Possible reserves are those unproved reserves which analysis of geological and engineering data suggests are less likely to be recoverable than probable reserves. In this context, when probabilistic methods are used, there should be at least a 10% probability that the quantities actually recovered will equal or exceed the sum of estimated proved plus probable plus possible reserves.
P$_{50}$	The quantity that has at least 50% probability of being exceeded
P$_{90}$	The quantity that has at least 90% probability of being exceeded
Paleocene	Geologic term covering period between 65 and 55.5 million years ago
Paleogene	Geologic term covering period between 65 and 23 million years ago
Pennsylvanian	Geologic term covering period between 320 and 286 million years ago
Permian	Geologic term covering period between 286 and 248 million years ago
Phanerozoic	Relating to or belonging to the aeon of geological time that consists of the Palaeozoic, Mesozoic and Cenozoic eras
Play	Recognised prospective trend of potential prospects, but which requires more data acquisition and/or evaluation to define specific leads or prospects
Poikiloaerobic	See dysaerobic
Post	After
ppm	Parts per million
Pristane/Phytane Ratios	The ratio of these two acyclic isoprenoid alkanes used to indicate the degree of oxygenation. Pristane/Phytane ratios of >1 indicated oxic conditions of sedimentation (at the sediment/water interface), whilst values of <1 reflected anoxic conditions.
Progradation	The accumulation of sequences by deposition in which beds are deposited successively basinward because sediment supply exceeds accommodation. Thus, the position of the shoreline migrates into the basin during episodes of progradation, a process called regression
Prospect	A project associated with a potential accumulation that is sufficiently well defined to represent a viable drilling target. A project maturity sub-class that reflects the actions required to move a project toward commercial production.

Term	Description
Prospective Resources	Those quantities of petroleum which are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations.
Proved Reserves	Often referred to as 1P, also as "Proven"
PSC	Production Sharing Contract
Recovery	The fraction of hydrocarbons that can or has been produced from a well, reservoir or field; also, the fluid that has been produced
Reservoir	A subsurface body of rock having sufficient porosity and permeability to store and transmit fluids. Sedimentary rocks are the most common reservoir rocks because they have more porosity than most igneous and metamorphic rocks and form under temperature conditions at which hydrocarbons can be preserved. A reservoir is a critical component of a complete petroleum system
Rift(ing)	The tearing apart of a plate to form a depression in the Earth's crust and often eventually separating the plate into two or more smaller plates
Risk	The probability of loss or failure. As "risk" is generally associated with the negative outcome, the term "chance" is preferred for general usage to describe the probability of a discrete event occurring
Rock Pyrolysis	Rock-Eval pyrolysis is a means of rapidly estimating these values on either kerogen or whole rock through the Hydrogen Index (mg hydrocarbon/g organic carbon). A separate module on this instrument also provides a measure of the total organic carbon content ("TOC"), the parameter usually used to indicate source rock richness. T_{max}, the Rock-Eval temperature (°C) at the point of maximum hydrocarbon evolution during pyrolysis, is a measure of the thermal maturity of the sample, with the oil window typically falling in the range of 430°C to 455°C.
Royalty	Royalty refers to payments that may be due to the host government, mineral owner, or landowner, in return for the producer having access to the petroleum. Many agreements allow for the producer to lift the royalty volumes, sell them on behalf of the royalty owner, and pay the proceeds to the owner. A few agreements provide for the royalty to be taken only in kind by the royalty owner
Sapropelic	A mud rich in organic matter formed at the bottom of a body of water
scfpd	Standard cubic foot per day (at 60°F and 14.7psia)
Section	A unit of measurement in US land allocation. Equal to 1 square mile, or 640 acres
Sedimentary	Types of rock that are formed by the deposition of material at the Earth's surface and within bodies of water
Seismic	Pertaining to waves of elastic energy, such as that transmitted by P-waves and S-waves, in the frequency range of approximately 1 to 100 Hz. Seismic energy is studied by scientists to interpret the composition, fluid content, extent and geometry of rocks in the subsurface
Shale	A fine-grained, fissile, detrital sedimentary rock formed by consolidation of clay- and silt-sised particles into thin, relatively impermeable layers. It is the most abundant sedimentary rock. Shale can include relatively large amounts of organic material compared with other rock types and thus has potential to become a rich hydrocarbon source rock, even though a typical shale contains just 1% organic matter.
STOIIP	Stock tank oil initially in place
Stratigraphy	The study of the history, composition, relative ages and distribution of strata, and the interpretation of strata to elucidate Earth history. The comparison, or correlation, of separated strata can include study of their lithology, fossil content, and relative or absolute age, or lithostratigraphy, biostratigraphy, and chronostratigraphy
Stripping Ratio	The ratio of the volume of overburden (or waste material) required to be handled in order to extract some volume of ore. For example, a 3:1 stripping ratio means that mining one cubic meter of ore will require mining three cubic meters of waste rock.
Syn-	At the same time as
Taxes	Enforced contributions to the public funds, levied on persons, property, or income by governmental authority

Term	Description
tcf	trillion cubic feet ($1x10^{12}$ ft^3)
Tertiary	Geologic term covering period between 65 and 2.6 million years ago
Thrust fault	A reverse fault marked by a dip of 45º or less
TOC	See total organic carbon
ton	Short ton
tonne	Metric ton
Total Organic Carbon	The term used to describe the level of carbon bound up in the organic compounds found within the source rock. Often referred to as TOC
tpa	Tonnes per annum
Trap	A configuration of rocks suitable for containing hydrocarbons and sealed by a relatively impermeable formation through which hydrocarbons will not migrate. Traps are described as structural traps (in deformed strata such as folds and faults) or stratigraphic traps (in areas where rock types change, such as unconformities, pinch-outs and reefs). A trap is an essential component of a petroleum system
trn	Trillion ($1x10^{12}$)
Turbidite	A sedimentary deposit formed by a turbidity current
Turbiditic	Pertaining to, or arising from turbidite, a sedimentary deposit formed by a turbidity current
Turbidity current	A fast-flowing downhill current (of air or water) that carries silt
Updip	Located up the slope of a dipping plane or surface. In a dipping (not flat-lying) hydrocarbon reservoir that contains gas, oil and water, the gas is updip, the gas-oil contact is downdip from the gas, and the oil-water contact is still farther downdip
Valanginian	Geologic term covering period between 131 and 122 million years ago
Vitrinite	A coal maceral (organic component) that is used in the determination of coal rank and organic maturity levels by means of measuring its reflectivity ("VR")
Vitrinite reflectance	A means of measuring the maturity of the organic matter within either the reservoir or the source rock, as regards whether the organic matter has been or could be an effective source rock ("VR")
Vug	A cavity, void or large pore in a rock
Working interest	A company's equity interest in a project before reduction for royalties or production share owed to others under the applicable fiscal terms

Source: SP Angel

Research Disclosures

Zac Phillips

Zac has in excess of 17 years' experience in Oil & Gas and finance, working for companies such as BP, Chevron, Merrill Lynch and ING Barings, where he undertook finance or finance related roles. Given his Chemical Engineering degree and PhD, Zac's career has focused on the economics of investment, and its assessment, on a range of projects from process change implementation, to operating plants and companies.

Zac's extensive Oil & Gas financial and technical experience has ably lent itself to the valuation of exploration and producing Oil & Gas assets, especially where complex financial structures define companies' access to the economic benefits of ownership. Latterly, Zac was the CFO to Dubai World's Oil & Gas business (DB Petroleum), with responsibility for risk management, valuation and the authoring of investment proposals. During this time, Zac valued in excess of 152 transactions with a combined transaction value of in excess of $40bn.

Zac has an Honours Degree in Chemical Engineering from Wales and a PhD in Chemical Engineering from Bath University. He is a member of the Society of Petroleum Engineers, Institute of Chemical Engineers, American Association of Petroleum Geologists, the Association of International Petroleum Negotiators and is an Approved Person under the Financial Conduct Authority in the United Kingdom.

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Table 40 – SP Angel Corporate Finance Research Recommendations

Recommendation	Coverage Universe		Investment Banking Clients	
	Number	% of total	Number	% of total
Buy	26	67%	16	62%
Hold	5	13%	2	8%
Sell	-	-	-	-
N/R	8	21%	8	31%
Total	**39**	**100%**	**26**	**100%**

Source: SP Angel

Table 41 – SP Angel Corporate Finance Research Breakdown – Investment Banking Clients

Category	Number	% of Total
Investment Banking Clients	26	67%
Non-Associated	13	33%
Total	**39**	**100%**

Source: SP Angel

Table 42 – SP Angel Corporate Finance Research Breakdown – Sector Recommendations

Sector	Buy	Hold	Sell	N/R	Total
Metals & Mining	15	2	-	1	18
Oil & Gas	6	2	-	-	8
Property	-	-	-	1	1
Technology	5	1	-	2	8
Other	-	-	-	4	4
Total	**26**	**5**	**-**	**8**	**39**

Source: SP Angel

SP Angel Corporate Finance LLP definition of research ratings:

Expected performance over 12 months

Buy - Expected return of greater than +10%
Hold - Expected return from -10% to +10%
Sell - Expected return of less than -10%

NOTE:

* SP Angel acts as broker to this company

** SP Angel acts as NomAd to this company

*** SP Angel acts as broker & NomAd to this company

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