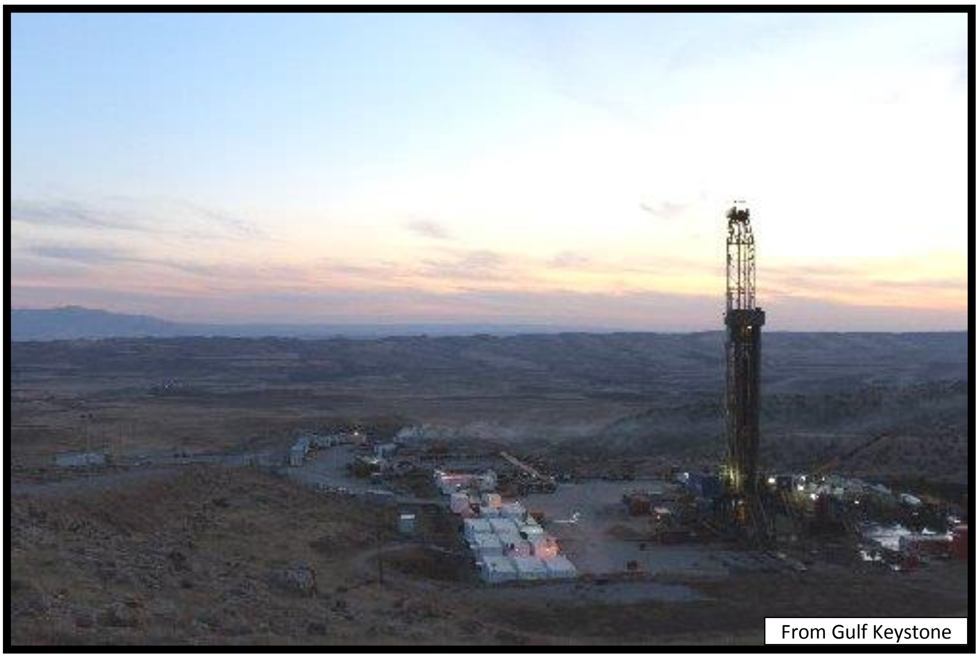
Competent Person's Report on the Interests of Gulf Keystone Petroleum and its Subsidiaries in the Shaikan Field, Kurdistan, Iraq as at 30 June 2016



From Gulf Keystone

PREPARED FOR: Gulf Keystone Petroleum

BY: ERC Equipoise Limited

Month: August

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ERC Equipoise Ltd, 6th Floor Stephenson House, 2 Cherry Orchard Road, Croydon, CR0 6BA
Tel: 020 8256 1150 Fax: 020 8256 1151
Registered England No. 03587074 Registered Office Eastbourne House, 2 Saxbys Lane, Lingfield, Surrey, RH7 6DN

Authors: S Hattingh, D Munn, A Symms, D Wilson, G Privett, K Al Marei, J Ramsay, P Chernik, J Ho, M Braim, G Boyd

Approved by: S McDonald

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1. Executive Summary

ERC Equipoise Limited (ERCE) has reviewed and evaluated the Shaikan field in the Shaikan Production Sharing Contract (PSC) concession in the Kurdistan region of Iraq in which Gulf Keystone Petroleum Limited (GKP) has an interest (Figure 1.1). GKP is the operator of the Shaikan PSC and has a 75% working interest plus 5% held by Texas Keystone Inc. (TKI) in trust. The other 20% interest in the PSC contractor group is held by MOL.

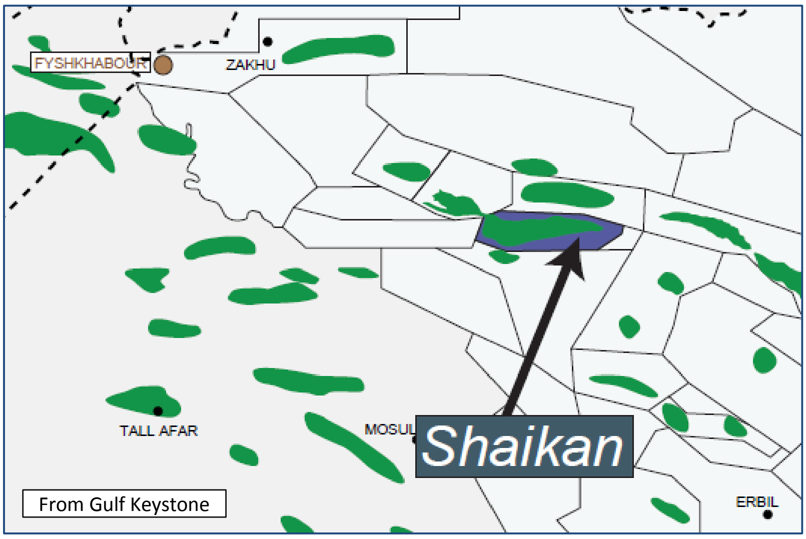


Figure 1.1: Location Map of GKP Licence Blocks

At the time of preparing this report, GKP's working interest in the Shaikan PSC is 75%. An additional 5% working interest is held in trust by TKI for GKP.

The PSC (2007) as amended by the First Amendment (2010) allows for the Kurdistan Regional Government (KRG) to back in up to 20% and a Third Party Participation nominated by the KRG to take up to a maximum of 15%. Under this scenario, GKP's interest would be diluted to 54.4% (comprising 51.0% for GKP and 3.4% for the interest held in trust by TKI). ERCE has been informed by GKP that it has entered in to an agreement with Kurdistan Ministry of Natural Resources (MNR) dated 16 March 2016 (the March Agreement) which confirms the KRG's back in right of 20%. In addition, the new agreement assigns half of the Third Party interest (7.5%) to the non-government contractors pro rata to their existing working interests with the remaining 7.5% to be held by the MNR. Also the Capacity Building Value for GKP and TKI is reduced from 40% to 30%.

The March Agreement has still to be ratified by all parties through an amendment to the PSC. If amended, GKP's working interest under the PSC will be 58.0% (comprising 54.375% for GKP and 3.625% for TKI) with a cost exposure of 64.0% and the Capacity Building Value for GKP and TKI will be reduced from 40% to 30%.

GKP has requested that ERCE's Base Case economic evaluation is based on the terms set out in the March Agreement. ERCE has also run economic sensitivity cases under the terms of the current PSC assuming both fully diluted and undiluted interests.

ERCE previously evaluated GKP's assets in Kurdistan and prepared a CPR dated March 2014, which was incorporated into GKP's Prospectus for the transfer of its listing from the London Stock

Exchange's Alternative Investment Market (AIM) to the Main Market. The CPR prepared by ERCE for GKP's listing ("the Listing CPR") has an effective date of 31 December 2013 and incorporates data received from GKP up to 31 December 2013. A subsequent CPR with an effective date of 30 September 2015 was issued in September 2015 and incorporated data received from GKP up to 30 June 2015. This current CPR, which covers the Shaikan field only, has an effective data of 30 June 2016 and includes data received from GKP up to 30 June 2016. The current CPR therefore incorporates new information spanning twelve months and predominantly comprises additional production and dynamic information gathered from the Jurassic reservoirs, GKP's updated development plans and new cost estimates following completion of a Front End Engineering and Design (FEED) study by a contractor. No new wells have been drilled in the field since the last CPR. The new information has been taken into account by ERCE in the preparation of this CPR, which is a stand-alone document reflecting the latest understanding of the Shaikan field.

The new dynamic data in the form of flow rates from nine producing wells and additional downhole pressure measurements in ten wells gathered during the past twelve months continue to support GKP's interpretation that depletion drive with possible gas cap expansion is occurring in the Jurassic reservoir. ERCE has audited GKP's recovery factors and production forecasts according to the current understanding of the drive mechanism and updated development plan. The Reserves estimates reported in this CPR reflect the current understanding of reservoir dynamics and are based on GKP's latest development plan.

A depth map to the top of the Jurassic interval over Shaikan is presented in Figure 1.2.

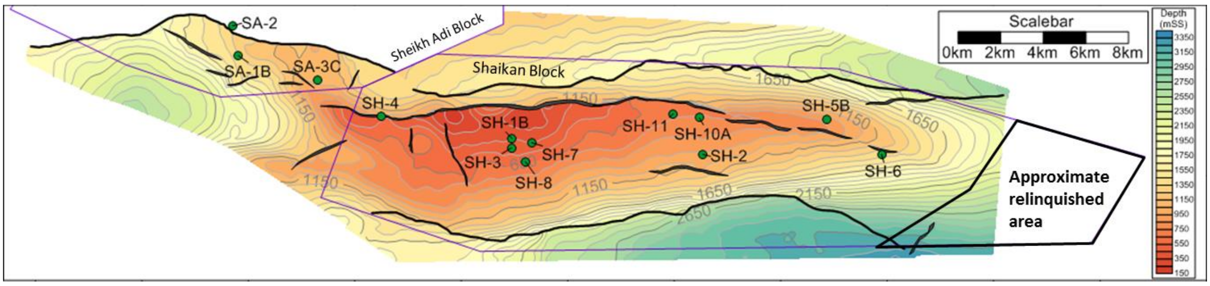


Figure 1.2: Top Jurassic Structure Depth Map of Shaikan (m TVDSS)

ERCE has estimated and reported the volumes of petroleum in place, Reserves, Contingent Resource and Prospective Resources in accordance with the March 2007 "Petroleum Resources Management System" (SPE PRMS), sponsored by the Society of Petroleum Engineers (SPE), the American Association of Petroleum Geologists (AAPG), the World Petroleum Council (WPC) and the Society of Petroleum Evaluation Engineers (SPEE) (see Section 6). The results of ERCE's evaluation are summarised in Table 1.1 to Table 1.9.

The assessment of Reserves reported in this CPR is based on the assumption that GKP will receive payment for produced hydrocarbons according to pricing assumptions used by ERCE. Furthermore, the assessment is based on the assumption that GKP's Shaikan Joint Venture partner MOL Hungarian Oil and Gas plc (MOL) and the Kurdistan authorities will approve the development plan as described herein, that a Final Investment Decision (FID) will be taken by the end of 2017 and that GKP will have the resources to implement the plan.

GKP has discovered oil in the Cretaceous, Jurassic and Triassic intervals and gas in the Triassic interval of the Shaikan field. The discovery was made by Well Shaikan-1B in 2009. The field has subsequently been appraised and an initial phase of development has been implemented, with a total of ten exploration, appraisal and development wells having been drilled at the time of preparing this report. GKP has acquired a comprehensive dataset include seismic data, cores, petrophysical logs and fluid samples. Multiple flow tests have been carried out including an extended test in two wells and intermittent interference testing since October 2010.

The Jurassic reservoirs have been on stream almost continuously since December 2013, apart from a period between mid-February 2015 and mid-March 2015 and a period from the latter part of February to mid-March 2016 when the field was shut in due to disruption of the pipeline export route through Turkey. Production was initially from two wells flowing at a combined rate of approximately 10 Mstb/d. This was progressively ramped up with more wells coming on stream. The current peak deliverability of the wells is close to the handling capacity of the production facilities of 45 Mstb/d. The field produced at an average oil rate of approximately 33 Mstb/d from up to nine wells during the period from 1 January 2016 to 30 June 2016. The average rate was adversely affected by the shut down early in the year. During the past three months production has remained steady at approximately 39 Mstb/d. Production has been primarily from the upper Jurassic with eight wells producing from these intervals and one well producing from the lower Jurassic. Cumulative oil production to 30 June 2016 was 25.1 MMstb. Since June 2015 crude oil has been exported by truck some 120 km to oil export facilities at Fishkabour on the border between Iraq and Turkey, and then injected into the Kirkuk to Ceyhan export pipeline through Turkey for sale at Ceyhan.

GKP declared the field commercial with "The First Commercial Declaration Date" under the terms of the PSC set at 1 August 2012. GKP submitted a field development plan (FDP) to the Kurdistan authorities in 2013 for the development of Shaikan in multiple phases and ERCE has been informed by GKP that the development was approved.

GKP defined an initial phase of development comprising 26 production wells, which formed the basis for ERCE's estimates of Reserves reported in the Listing CPR. At the time of preparing the Listing CPR, understanding of reservoir dynamic behaviour was in its infancy and the Reserves estimates were based on the premise that natural aquifer influx would be the primary drive mechanism. Dynamic data acquired over the past two years has shown good communication across the upper Jurassic and slowly declining reservoir pressure that can be reconciled with material balance calculations. It now appears more likely that the primary drive mechanism will be gas cap expansion and gravity drainage and GKP has accordingly modified the development plans.

In addition to the nine existing production wells, GKP's current plan comprises 32 production wells in the Jurassic reservoirs, one production well in the Cretaceous and five production wells in the Triassic reservoirs. Two further wells for gas injection and one water disposal well are planned in addition to a Permian exploration well. The development plan includes facilities upgrades to a maximum oil production capacity of 115 Mstb/d and the construction of a spur pipeline from the field to the main trunk export pipeline. We refer to this development in this CPR as 'Shaikan Phase 1-2', as it includes all of Phase 1 as described in the FDP and a substantial portion of Phase 2. The

Reserves reported in this CPR are therefore based on the implementation of the Shaikan Phase 1-2 development.

This revised 'Shaikan Phase 1-2' plan was submitted to the Kurdistan authorities in a Field Development Plan Update ("FDP Update") report in December 2015. It was anticipated that approval of this plan would occur in 2016, with first oil through the new facilities occurring in early 2019.

In the light of the current low oil price environment, in early 2016 GKP and its partners deferred a Final Investment Decision ("FID") for the FDP Update until end-2017, which will result in a one year delay in first oil through the new production facilities. Significant expenditure on the new plant is now planned to commence in 2018 and first oil through the new facilities in 2020.

An interim plan, termed the "Bridge to the FDP" has been formulated, which details activities and expenditure to mitigate the expected decline in oil rate from the existing well stock and maintain current production levels through the existing plant prior to FID for the FDP Update at end-2017. This plan envisages some debottlenecking work to be carried out at the end of 2016 that will lower the inlet pressure to the separators, the installation of desalters to treat produced emulsions believed by Gulf Keystone to be formed by the mixing of oil with drilling fluid lost to the reservoir during drilling and completion, the drilling of a single well in the second half of 2017 and the installation of four electrical submersible pumps (ESPs) from April 2017 to boost the production rates. We have assumed this interim plan is implemented in this CPR.

The Bridge to the FDP also presents an alternative interim investment scenario whereby an additional temporary production facility is installed in the field, increasing capacity in the interim period from 45 Mstb/d to 55 Mstb/d. This scenario has not been considered further in this CPR.

ERCE has made estimates of hydrocarbons initially in place (Table 1.8) and estimates of recoverable volumes of oil and gas for the Jurassic, Triassic and Cretaceous intervals. We have classified the portions of these volumes that are estimated to be economically recoverable within the licence period upon implementation of the 'Shaikan Phase 1-2' development plan as Reserves (Table 1.1). The gross field Proved plus Probable (2P) oil Reserves estimated by ERCE for the Phase 1 development of the Jurassic interval in Shaikan amount to 575 MMstb, for the Triassic the 2P oil Reserves are estimated to be 44 MMstb and for the Cretaceous they are 3 MMstb.

The remaining volumes that are estimated to be potentially recoverable within the licence period, but for which no definite plans are in place have been classified as Contingent Resources (Table 1.4 and Table 1.5). The gross field 2C Contingent Resources estimated by ERCE for the Jurassic interval in Shaikan amount to 80 MMstb of oil and 305 Bscf of solution gas. For the Triassic, the gross field 2C Contingent Resources are estimated to be 106 MMstb and 648 Bscf and for the Cretaceous, they are estimated to be 53 MMstb.

The Shaikan PSC terms allow for a Development Period of 20 years with an automatic right to a five year extension, followed by a further five year extension that can be applied for. This gives an effective Development Period of 30 years after which the PSC contract will expire. GKP has informed ERCE that the 30 year period expires on 30 June 2043. There is no assurance that GKP will receive an extension beyond 30 years and the terms that would apply should a further extension be granted are unknown.

Due to the time factor of gravity drainage of oil from matrix blocks by gas cap expansion, ERCE estimates that some volumes that are recoverable over time might not be recovered within the licence period. We have reported these in Table 1.6 as 'Technically recoverable volumes'. We have not classified these volumes as Contingent Resources as the question of ownership after expiry of the licence period has not been confirmed. Should GKP be granted an extension to the licence beyond the 30 year period, portions of these volumes (depending on GKP's equity) would be candidates for reporting as Reserves and/or Contingent Resources.

We have constructed an economic model that incorporates estimates of future production volumes of petroleum for the planned development of Shaikan together with estimates of future expenditure and commodity price scenarios to estimate economic cut-off dates for reporting a range of estimates of gross field Reserves. We have incorporated the current fiscal terms governing the Shaikan licence block to estimates Net Present Values (NPV) for Reserves. The results are presented in Table 1.2. The future oil price assumptions are shown in Table 1.3.

ERCE has evaluated and reported Prospective Resources for the deep Triassic age Kurre Chine D formation, and for the shallow Cretaceous age Qanchuqa formation where potential exists for moveable hydrocarbons within a depth windows related to temperature (Table 1.7).

Summary of Results. A summary of the estimates of Reserves is shown in Table 1.1. The results of the economic evaluation of Reserves are shown in Table 1.2, based on the oil price scenario shown in Table 1.3 and an oil price quality discount to Brent specified by GKP. The oil price discount is based upon a marketing study prepared by Channoil Consulting Limited (Channoil) at the request of GKP; the discount used for the "2P" Reserves varies between $13.1 / stb and $14.7 / stb over the life of the forecast. The Ministry of Natural Resources (MNR) of the Kurdistan Regional Government (KRG) currently purchases Shaikan crude at a discount of $14.7 / stb. GKP has informed ERCE that a Heads of Terms Agreement has been concluded with the MNR, which provides that the discount applicable ($14.7 / stb) is subject to revision and the retroactive application of a Quality Bank pricing formula, potentially based on an independent third party valuation such as the Channoil study.

Summaries of estimates of Contingent Resources are shown in Table 1.4 for oil and in Table 1.5 for gas. A summary of volumes estimated to be recoverable beyond the expiry date of the PSC licence is shown in Table 1.6. A summary of estimates of Prospective Resources is shown in Table 1.7. A summary of estimates of discovered volumes of oil initially in place (STOIIP) and gas initially in place (GIIP) is shown in Table 1.8. A summary of estimates of undiscovered volumes of STOIIP is shown in Table 1.9. No economic evaluation of Contingent Resources or Prospective Resources has been carried out by ERCE.

Reserves *are 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 as Proved (1P), Proved plus Probable (2P) and Proved plus Probable plus Possible (3P).*

Oil Reserves as of 30 June 2016 shown in Table 1.1 are for Shaikan Phase 1-2 development of the Jurassic, Triassic and Cretaceous intervals of the Shaikan field comprising 51 wells and maximum oil processing capacity of 115 Mstb/d. They do not include volumes estimated to be recoverable from the field after expiry of the PSC licence on 30 June 2043. The results of an economic evaluation are shown in Table 1.2 using the oil price assumptions shown in Table 1.3.

Table 1.1: Summary of Oil Reserves

Field	Formation	Gross Field Oil Reserves (MMstb)			GKP WI (%)	GKP Working Interest Oil Reserves (MMstb)			GKP Net Entitlement Oil Reserves (MMstb)		
		1P	2P	3P		1P	2P	3P	1P	2P	3P
Shaikan	Cretaceous	1	3	4	58.0	1	2	2	79	161	203
Shaikan	Jurassic	219	575	883	58.0	127	333	512			
Shaikan	Triassic	18	44	63	58.0	10	25	37			
Shaikan	**Total**	**238**	**622**	**951**	**58.0**	**138**	**360**	**551**	**79**	**161**	**203**

Notes

1) "Gross Field Reserves" are 100% of the volumes estimated to be economically recoverable from the fields from 30 June 2016 onwards, up to expiry of the PSC licence on 30 June 2043.
2) GKP "Working Interest (WI) Reserves" are GKP's working interest fraction of the gross resources. They are not GKP's Net Entitlement under the terms of the PSC that governs this asset.
3) GKP "Net Entitlement Reserves" are the sum of GKP's share of cost recovery oil plus GKP's portion of the Contractor's share of profit oil under the PSC terms in Kurdistan.
4) GKP's profit oil is net of royalty and is calculated before deductions for Capacity Building Payments.
5) The evaluation of Net Entitlement Barrels includes an additional entitlement from "Tax Barrels" arising from the deemed Corporate Income Tax under the PSC paid on GKP's behalf from the Government's share of Profit Petroleum.
6) The working interest used in this report for the Shaikan PSC is 58.0%.

Table 1.2: Summary of Base Case Economic Evaluation of Reserves (with GKP oil price discount)

Reserves Category	Economic limit (year)	GKP Net Entitlement Reserves (MMstb)	Net Present Value Net to GKP at 1 July 2016 (US$ million Nominal). At annual discount rates of:					Gross field Reserves (MMstb)
			0%	5%	10%	15%	20%	
1P	2029	79	812	501	306	180	99	238
2P	2043	161	3,067	1,759	1,089	708	477	622
3P	2043	203	4,615	2,374	1,364	849	559	951

Table 1.3: Oil Price Assumption for Economic Evaluation

Brent Crude Oil Price (Nominal)	2016	2017	2018	2019	2020	2021	2022	2023+
Real (constant $, 2016)	46	53	60	65	68	70	70	70
Nominal ($ of the day)	46	54	63	69	74	78	79	+2.0% pa

Contingent Resources *are 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 categorized in accordance with the level of certainty associated with the estimates as 1C, 2C and 3C.*

All Contingent Resources shown in Table 1.4 are contingent on the definition of development plans and the demonstration of commerciality. They do not include volumes estimated to be recoverable from the field after expiry of the PSC licence on 30 June 2043.

Table 1.4: Summary of Oil Contingent Resources

Field/ Licence	Formation	Gross Field Oil Contingent Resources (MMstb)			GKP WI (%)	GKP Net WI Oil Contingent Resources (MMstb)		
		1C	2C	3C		1C	2C	3C
Shaikan	Cretaceous	14	53	175	58.0	8	31	102
	Jurassic	97	80	340		56	46	197
	Triassic	29	106	347		17	61	201
Total		**140**	**239**	**862**		**81**	**138**	**500**

Notes

1) "Gross Field Contingent Resources" are 100% of the volumes estimated to be recoverable from the fields without any economic cut-off being applied from 30 June 2016 onwards, up to expiry of the PSC licence on 30 June 2043.
2) GKP "Working Interest (WI) Contingent Resources" are GKP's working interest fraction of the gross resources. They are not GKP's Net Entitlement under the terms of the PSCs that govern these assets, which can be expected to be lower.
3) Contingent Resources are estimates of volumes that might be recovered from the field under as yet undefined development scheme(s). It is not certain that the fields will be developed or that the volumes reported as Contingent Resources will be recovered.
4) The volumes reported here are unrisked in that they have not been multiplied by a chance of development.

Gas volumes shown in Table 1.5 are solution gas, apart from the gas reported for the Triassic interval where a portion of the gas is from a gas cap. Gas Contingent Resources are subject to the same contingencies as the corresponding Oil Contingent Resources shown in Table 1.4. In addition, they are contingent on securing gas sales agreements and gas export routes.

Table 1.5: Summary of Gas Contingent Resources

Field/ Licence	Formation	Gross Field Gas Contingent Resources (Bscf)			GKP WI (%)	GKP Net WI Gas Contingent Resources (Bscf)		
		1C	2C	3C		1C	2C	3C
Shaikan	Cretaceous	0	0	0	58.0	0	0	0
	Jurassic	102	305	772		59	177	448
	Triassic	292	648	1,583		169	376	918
Total		**394**	**953**	**2,355**		**228**	**553**	**1,366**

Notes
1) "Gross Field Contingent Resources" are 100% of the volumes estimated to be economically recoverable from the fields without any economic cut-off being applied from 30 June 2016 onwards, up to expiry of the PSC licence on 30 June 2043.
2) GKP "Working Interest (WI) Contingent Resources" are GKP's working interest fraction of the gross resources. They are not GKP's Net Entitlement under the terms of the PSCs that govern these assets, which can be expected to be lower.
3) Contingent Resources are estimates of volumes that might be recovered from the field under as yet undefined development scheme(s). It is not certain that the fields will be developed or that the volumes reported as Contingent Resources will be recovered.
4) The volumes reported here are unrisked in that they have not been multiplied by a chance of development.
5) Gas Contingent Resources are estimates of recoverable hydrocarbon gas volumes and exclude any non-hydrocarbon volumes that might be produced.
6) To the extent that gas is flared after the effective date of this report, the gas Contingent Resources reported for Shaikan Jurassic will be reduced.

Technically Recoverable Oil volumes

Volumes reported in Table 1.6 are estimated to be recoverable from the fields after the expiry of the PSC licence on 30 June 2043, based on current understanding of the recovery processes likely to prevail in the fractured reservoirs. They are not classified as Reserves or Contingent Resources as ownership after licence expiry is unknown.

Table 1.6: Summary of Technically Recoverable Oil Volumes After Licence Expiry

Field/ Licence	Formation	Gross Field Oil Technically Recoverbale Volumes (MMstb)		
		Low	Best	High
Shaikan	Cretaceous	0	0	0
	Jurassic	84	132	219
	Triassic	10	18	35
Total		**94**	**150**	**254**

Notes
1) "Gross Field Technically Recoverable Volumes" are 100% of the volumes estimated to be recoverable from the fields without any economic cut-off being applied after expiry of the PSC licence on 30 June 2043.
2) The volumes reported here are unrisked in that they have not been multiplied by a chance of development.

Prospective Resources *are 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 (COS) 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 as Low, Best and High. Prospective Resources can be sub-classified as Prospects, Leads and Plays. A Prospect is a potential accumulation that is sufficiently well defined to represent a viable drilling target. A Lead is a potential accumulation that is currently poorly defined and requires more data acquisition and/or evaluation in order to be classified as a prospect. A Play is a prospective trend of potential prospects, but which requires more data acquisition and/or evaluation in order to define specific leads or prospects.*

Table 1.7: Summary of Unrisked Oil Prospective Resources (Prospects)

Block/ Licence	Prospect	Gross Field Oil Prospective Resources (MMstb)			GKP WI (%)	GKP Net WI Oil Prospective Resources (MMstb)			COS (%)
		Low	Best	High		Low	Best	High	
Shaikan	Qamchuqa	6	23	85	58.0	4	13	49	50
	Triassic KCD	17	42	105		10	24	61	28

<u>Notes</u>

1) Prospects are features that have been sufficiently well defined through analysis of geological and geophysical data that they are considered drillable targets.
2) "Gross Field Unrisked Prospective Resources" are 100% of the volumes estimated to be recoverable from an accumulation.
3) GKP "Working Interest Prospective Resources" are GKP's working interest fraction of the gross resources. They are not GKP's Net Entitlement under the terms of the PSCs that govern these assets, which can be expected to be lower.
4) The geological chance of success (COS) reported here is an estimate of the probability that drilling the Prospect would result in a discovery as defined under SPE PRMS (Section 6).
5) Prospective Resources reported here are "unrisked" in that the volumes have not been multiplied by the COS.

Discovered Petroleum Initially-in-place *is that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production.*

Undiscovered Petroleum Initially-in-place *is that quantity of petroleum estimated, as of a given date, to be contained within accumulations yet to be discovered.*

Table 1.8: Summary of Discovered Oil and Gas Initially in Place

Field/ Licence	Formation	STOIIP (MMstb)			Free GIIP (Bscf)			Comments
		Low	Best	High	Low	Best	High	
Shaikan	Cretaceous above isotherm	475	553	645	0	0	0	No recovery reported
	Cretaceous below isotherm	653	842	1,344	0	0	0	
	Jurassic above 1,450 mSS	2,698	3,296	4,100	3	8	15	
	Jurassic below 1,450 mSS	1,791	2,159	2,677	0	0	0	
	Triassic	245	427	823	630	1,037	1,787	Gas is sour and rich

Notes

1) GIIP is free gas and excludes solution gas
2) GIIP is sour, wet gas

Table 1.9: Summary of Undiscovered and Prospective Oil Initially In Place

Field/ Licence	Formation	STOIIP (MMstb)		
		Low	Best	High
Shaikan	Qamchuqa	484	1,099	2,584
	Triassic KCD	51	123	316

Notes

1) Oil has been intersected in the Shaikan Qamchuqa, but volumes are reported as 'prospective' because no flow test has been carried out.

2. Introduction

ERC Equipoise Limited (ERCE) has reviewed and evaluated the Shaikan field in the Shaikan Production Sharing Contract (PSC) concession in the Kurdistan region of Iraq (Figure 1.1). At the time of preparing this report, GKP's working interest in the Shaikan PSC is 75%. An additional 5% working interest is held in trust by TKI for GKP.

The PSC (2007) as amended by the First Amendment (2010) allows for the KRG to back in up to 20% and a Third Party Participation nominated by the KRG to take up to a maximum of 15%. Under this scenario, GKP's interest would be diluted to 54.4% (comprising 51.0% for GKP and 3.4% for the interest held in trust by TKI). ERCE has been informed by GKP that it has entered in to an agreement with Kurdistan Ministry of Natural Resources (MNR) dated 16 March 2016 (the March Agreement) which confirms the KRG's back in right of 20%. In addition, the new agreement assigns half of the Third Party interest (7.5%) to the non-government contractors pro rata to their existing working interests with the remaining 7.5% to be held by the MNR. Also the Capacity Building Value for GKP and TKI is reduced from 40% to 30%.

The March Agreement has still to be ratified by all parties through an amendment to the PSC. If amended, GKP's working interest under the PSC will be 58.0% (comprising 54.375% for GKP and 3.625% for TKI) with a cost exposure of 64.0% and the Capacity Building Value for GKP and TKI will be reduced from 40% to 30%.

GKP has requested that ERCE's Base Case economic evaluation is based on the terms set out in the March Agreement. ERCE has also run economic sensitivity cases under the terms of the current PSC assuming both fully diluted and undiluted interests.

ERCE was engaged by GKP to carry out an independent assessment of Reserves, Contingent Resources and Prospective Resources for GKP's interest in the Shaikan field located in Kurdistan, Iraq and to report the results in the form of a Competent Person's Report (CPR). This assessment has been carried out in the form of an audit of GKP's own work. This CPR is an update of two previous assessments carried out by ERCE which were presented to GKP in March 2014 (the Listing CPR) and September 2015. The current CPR incorporates new information spanning twelve months and predominantly comprises additional production and dynamic information gathered from the Jurassic reservoirs, GKP's updated development plans and new cost estimates following completion of a FEED study. No new wells have been drilled in the field since the last CPR.

GKP is an independent oil and gas company registered in Bermuda, with further offices in Erbil in the Kurdistan Region of Iraq and in London in the UK. For the purpose of this report, ERCE has reviewed the Shaikan field, governed by a Production Sharing Contract (PSC) (Figure 2.1). GKP is the operator of the Shaikan block, having acquired the interest in November 2007.

3. Dataset

In its interpretation of the Shaikan field ERCE has relied upon data provided by GKP, as well as data available in the public domain. Data were made available up to the data cut-off date of 30 June 2016 other than where stated explicitly. The data included, amongst others:

- The Field Development Plan (FDP) and Addendum, the Appraisal Report and the Discovery Report.
- The Field Development Plan Update (FDP Update) and the interim investment plan The Bridge to the FDP.
- Documents, graphs and tables of general geological and well data
- Seismic workstation projects and interpretations together with time and depth structure maps for the Shaikan structure
- Structural models of various vintages in Petrel of the Shaikan field
- Well logs for most drilled wells
- Core data retrieved from select intervals
- Drilling and well reports
- Well test data and interpretations
- PVT reports for selected intervals within the Jurassic and Triassic
- PSC information, with past costs
- Daily historical production figures and pressure measurements for all producing Shaikan wells up to 30 June 2016
- The material balance model constructed by GKP in Excel.
- Production forecasts and cost information for GKP’s current and future development plans for the Shaikan field
- Analyses carried out by GKP and third parties pertaining to pressure transient analysis of production data, PVT reviews, material balance and production forecasting, petrophysical interpretations and fracture analyses for the Jurassic reservoirs in Shaikan.
- Facilities and associated cost information presented in the FDP Update and the Bridge to the FDP.
- Documents and cost information produced during a Front End Engineering and Design (FEED) study conducted in 2015 and 2016 by a contractor on GKP’s behalf.

ERCE has relied upon GKP for the completeness and accuracy of the dataset used in the preparation of this report. No site visit was undertaken during this evaluation. GKP has informed ERCE that there has been no material change in its portfolio between the data cut-off date, 30 June 2016 and the date of issue of this report.

4. Evaluation Basis

The dataset provided by GKP enabled ERCE to complete a satisfactory audit of:

- Volumes of oil and gas initially in place
- Oil Reserves
- An economic evaluation of oil Reserves
- Oil and gas Contingent Resources and oil Prospective Resources

For the purposes of economic modelling, ERCE constructed independent economic models, utilising the PSC and country fiscal system information presented by GKP.

ERCE has used standard petroleum evaluation techniques in the preparation of this report. These techniques combine geophysical and geological knowledge with assessments of porosity and permeability distributions, fluid characteristics and reservoir pressure. There is uncertainty in the measurement and interpretation of basic data. ERCE has estimated the degree of this uncertainty and determined the range of petroleum initially in place and recoverable hydrocarbons. Our methodology adheres to the guidelines of the SPE PRMS (Summarised in Section 6 of this report).

ERCE has evaluated the development scheme for the Shaikan field presented by GKP and has conducted an audit of the capital and operating costs prepared by GKP and also capital costs prepared by the FEED contractor. ERCE has audited production forecasts prepared by GKP for the existing development comprising nine production wells completed in the Jurassic interval of the Shaikan field and for further development plans for the Jurassic, Cretaceous and Triassic reservoirs of the Shaikan field. Audited production, Capex and Opex forecasts have then been used as input into the economic model. ERCE's economic analysis is based on the Kurdistan PSC applicable to Shaikan on a stand-alone basis and does not take into account any outstanding debt, nor future indirect corporate costs of GKP.

At the effective date of this report, GKP has not yet signed any gas sales agreements. In the estimation of future cash flows, ERCE has relied upon oil prices and contract terms assumed and provided by GKP, which may not reflect future signed contract values. There is no guarantee that actual economic parameters will match the assumed values. Note that the economic values associated with the Reserves calculations contained within this report do not necessarily reflect a fair market value. Values presented in this report have been calculated using the economic interest method.

The accuracy of estimates of forecast volumes of oil and gas and production and forecasts of future costs is a function of the quality and quantity of available data and of engineering interpretation and judgment. While estimates of Reserves and production forecasts, Contingent Resources and Prospective Resources presented herein are considered reasonable, these estimates should be accepted with the understanding that reservoir performance subsequent to the date of the estimate may justify revision, either upward or downward.

In the case of Contingent Resources presented in this report, there is no certainty that it will be commercially viable to produce any portion of the volumes of oil and gas. In the case of Prospective Resources presented in this report, there is no certainty that any portion of the volumes of oil and gas will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the volumes of oil and gas.

5. Shaikan Field

5.1. Introduction

The Shaikan field is located some 60 km north of Erbil in northern Kurdistan (Figure 1.1). Oil and gas condensate have been tested in naturally fractured formations in the Cretaceous, Jurassic and Triassic intervals. Oil from the Cretaceous is very heavy, although viscosity decreases with increasing depth and temperature. The Jurassic contains medium to heavy crude ranging in gravity from 18 °API at the top to 11 °API towards the base of the column. The GOR is approximately 390 scf/stb. The Triassic contains light oil and gas condensate. The oil contained within all intervals of the field has a high content of H_2S and CO_2.

The original discovery Well Shaikan-1B (also referred to as Well SH-1B) was drilled in November 2009 to a depth of 2,950 mMDRKB and oil was successfully tested. Appraisal drilling commenced in 2010, with the drilling of Well Shaikan-3 in December 2010 to a depth of 1,518 mMDRKB. In August 2011 Well Shaikan-2 was drilled to 3,300 mMDRKB and in December 2011. Well Shaikan-4 was drilled to 3,400 mMDRKB. In April 2012 Well Shaikan-6 was drilled on the eastern flank and is likely to be used for water disposal in the future. Subsequently, Well Shaikan-5B was drilled north-east of Well Shaikan-6 and Well Shaikan-8 were drilled in the vicinity of Well Shaikan-1B and Well Shaikan-3. Subsequent to the completion of the Listing CPR dated March 2014, GKP drilled Well Shaikan-7E in to the east of, and in proximity to, Well Shaikan-3. In addition, Well Shaikan-10A located north of Well Shaikan-2 and Well Shaikan-11, located north-east of Well Shaikan-2, were drilled. By mid-2015, Wells Shaikan-1B, -2, -3, -4, -5B, -7, -8, -10 and -11 had all been completed and brought on production.

GKP submitted an Appraisal Report to the Ministry of Natural Resources in Kurdistan in the third quarter of 2012. GKP declared the field commercial with “The First Commercial Declaration Date” under the terms of the PSC being set at 1 August 2012. GKP prepared and submitted a field development plan (FDP) to the Kurdistan authorities dated January 2013 for the development of the Shaikan field. The FDP focussed on exploitation of the Jurassic interval. At the request of the Kurdistan authorities, an Addendum to the FDP, dated June 2013, was submitted by GKP, which included a more aggressive and comprehensive development than the original FDP. The development of Shaikan was approved by the authorities following submission of the Addendum.

A revised ‘Shaikan Phase 1-2’ plan was submitted to the Kurdistan authorities in a Field Development Plan Update (“FDP Update”) report in December 2015. This plan includes facilities upgrades from a current oil production capacity of 45,000 stb/d to a maximum capacity of 115 Mstb/d and the construction of a spur pipeline from the field to the main trunk export pipeline. First oil through the new facilities was envisaged in 2019, although this date has now been deferred to 2020.

5.2. Seismic Interpretation

The Shaikan field is covered by 3D seismic data, acquired by Gulf Keystone in 2010. The seismic reference datum is 1,300 m above mean sea level. The original processed seismic volume exhibited poor image quality over the core of the anticline, where rocks of Cretaceous age are exposed and progressively eroded. Subsequently, GKP has undertaken post-stack reprocessing of the data over the whole of the Shaikan anticline, and image quality in the core of the anticline is much improved (Figure 5.1). The most recent PoSDM processing, completed subsequent to the Listing CPR, forms the basis of the most recent structural interpretation. Vertical Seismic Profiles (VSPs) have been acquired in Wells Shaikan-1B, Shaikan-2, Shaikan-4, Shaikan-5B and Shaikan-6 to tie wells to seismic data.

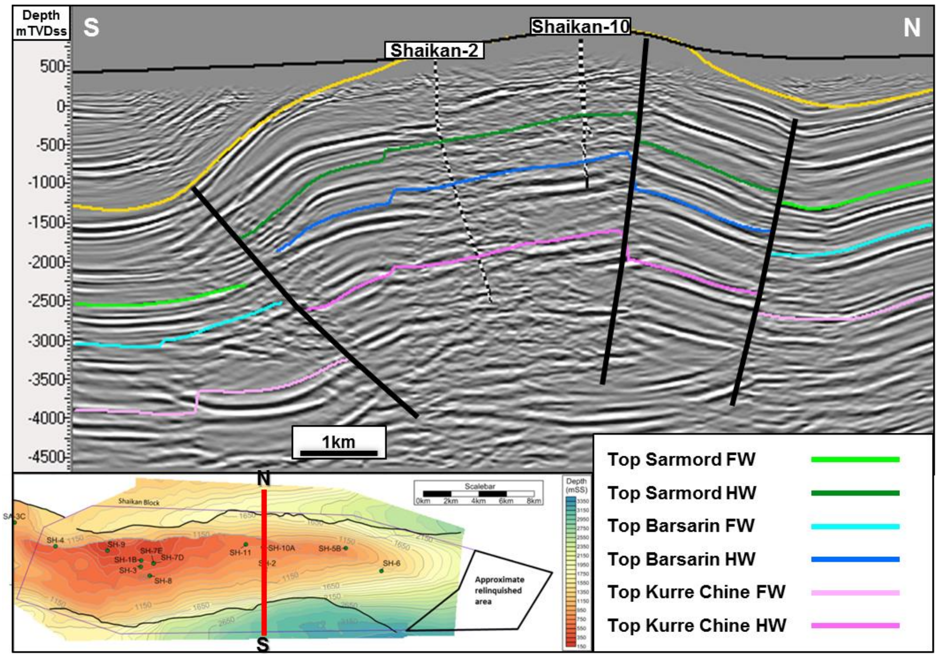


Figure 5.1: Dip Seismic Line, Shaikan Field

Using a combination of seismic mapping, extrapolation of structural dip, well formation dip and mapped surface structure, GKP has constructed a depth structure map of the Shaikan structure. In its simplest terms, the structure is a compressional, asymmetric anticline, with a faulted or possibly steeply folded northern limb and a subsidiary back fault developing to the south. It maps as dip closed plunging eastwards, connected to the Sheikh Adi structure to the northwest by a saddle with probable cross-faulting to the west of Well Shaikan-4. Care has been taken to map key markers (Sarmord, Barsarin and Kurre Chine) separately in the footwall and hanging wall, to ensure accurate reconstruction for volumetric purposes.

ERCE has reviewed the seismic interpretation carried out by GKP and has accepted it as a reasonable basis for estimating volumes. Although seismic image quality is now sufficient within the core of the Shaikan anticline to allow structural form to be mapped directly, we note that the field is likely to be more structurally complex than is currently mapped.

5.3. Depth Conversion

The Shaikan surfaces and horizons supplied by GKP had been interpreted on the PoSDM seismic volume, within the depth domain. The velocity model for this volume is described as relatively simplistic and model based, taking into account major velocity variations in the overburden. No correction was applied to the seismic volume to tie the wells so there are residual errors at well locations. Depth error maps were used to correct these at each reservoir level before gross rock volume calculation. These errors are mostly within the range ±100m, consistent with the depth error estimated for the previous velocity model over the core of the field. The top Jurassic depth map for Shaikan based on the GKP seismic interpretation and used by ERCE for volumetric estimation is shown in Figure 5.2.

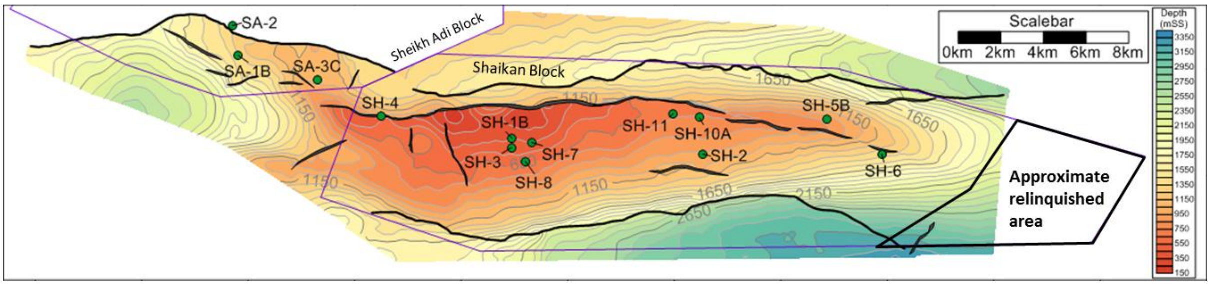


Figure 5.2: Shaikan Top Jurassic Depth Map

5.4. Geological Description

5.4.1. Reservoir Description

Hydrocarbons were discovered in the fractured carbonates of the Cretaceous, Jurassic and Triassic intervals (Figure 5.3). Cores were cut in a number of the wells and wireline logs were acquired in all wells. However, Wells Shaikan-3, Shaikan-8, Shaikan-10A and Shaikan-11 were terminated in the Jurassic interval and therefore no data are available from these wells for the Triassic.

The hydrocarbon bearing sections in the Cretaceous that ERCE has evaluated are the Sarmord, Garagu and Chia Gara. These reservoirs comprise dolomite, limestone and shale. Matrix porosity is generally in the range from 0% to 22% with permeability generally ranging between <0.01 and 50 md. The Sarmord, Garagu and Chia Gara appear, from logs, to have different fluid contacts and have been evaluated as separate reservoirs. Wells Shaikan-10A and Shaikan-11 have penetrated the northerly fault complex in the Garagu and potentially in the Chia Gara, which has led to structural thickening of the well isochores.

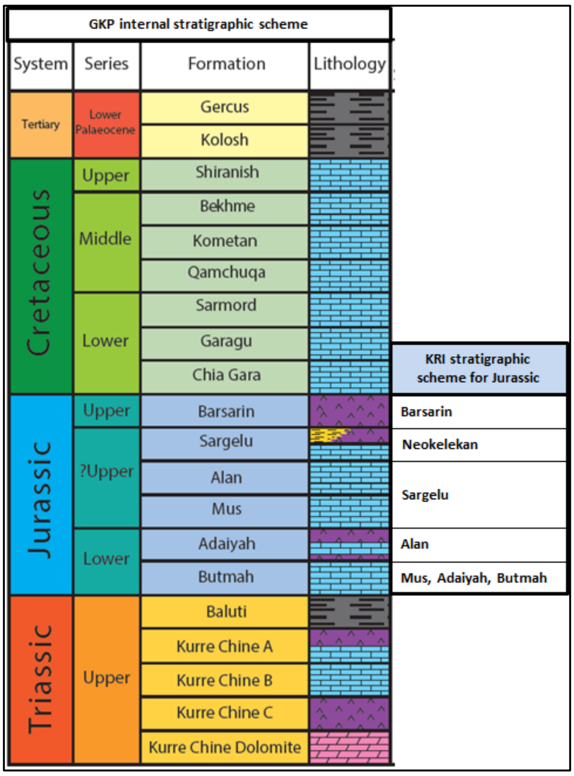


Figure 5.3: Shaikan Stratigraphy

The Jurassic reservoir comprises, from the top, the Sargelu, Alan, Mus, Adaiyah and Butmah formations. The Barsarin formation at the top of the Jurassic is non-reservoir and the Adaiyah formation lying between the Mus and Butmah is poorer reservoir quality. Formation pressure data suggest that all the Jurassic reservoir intervals are in vertical static pressure equilibrium. Dolomite and anhydrite make up the majority of the lower part of the Jurassic, while limestone and anhydrite are prevalent in uppermost formations (Sargelu and Alan). Shales are also common across the field in the Sargelu. The lowermost Sargelu and Alan formations exhibit high gamma ray log responses, which are believed to be due to organic richness and the possible presence of bitumen. These formations are known to contain source rock in the region. The limited cored section and the results from the Nuclear Magnetic Resonance (NMR) and Elemental Capture Spectroscopy (ECS) logs prove that the interval represents a low porosity section, which contrasts markedly with values derived from the standard logs. This discrepancy has been fully accounted for in our calculations. Matrix porosity generally ranges from 0% to 15% with permeability from cores varying between <0.01 and 1 md, with occasional intervals up to 700 md.

Well Shaikan-4 penetrated the northerly fault within the Sargelu (Jurassic). Here, a repeat reservoir section due to the faulting is recognised, and from log evaluation it was concluded that hydrocarbons occur in both the hanging wall and footwall of the structure. Dips of 60^{o} were interpreted from the image logs adjacent to the thrust in Well Shaikan-4 and highlight the distortion occurring along the thrust. This distortion was accounted for in determining the thickness value for each of the geological intervals in this well.

The Triassic section has not been fully penetrated by any well in the field and the hydrocarbons discovered to date in the field occur within the Kurre Chine A, B and C formations. These comprise heavily anhydritic dolomites and limestones having porosity between 0 and 15% and permeability from <0.01 to 2.5 md.

5.4.2. Fracture Description

From the available data, comprising fieldwork, core and image logs, ERCE has concluded that two families of fractures are present in the Shaikan field. These are the small-scale fractures (including hairline, stylolites, stratabound joints and tension gashes), which form a background fracture system that is present throughout each reservoir interval and are often partially occluded by mineralisation. The second family of fractures at Shaikan are larger scale and include non-stratabound joints, 'fracture corridors' and sub-seismic faults. The presence of this latter category was inferred by GKP, because of the possible higher fracture density interpreted in the image logs of Shaikan-10A and Shaikan-11 and frequent rubble zones in the core.

Shaikan has the form of an elongate linear feature, probably controlled by the reactivation of a basement fault (Figure 5.2). The boundary faults to the north and south define an asymmetric anticline with hinge lines and relatively little crestal bending. Based on the observations from the well data, combined with an understanding of the structural geometry and drawing upon comparisons with other structures in the region, we estimated a range of bulk fracture porosity for the Jurassic reservoirs of 0.1%, 0.4% and 0.7% for low, mid and high cases during the preparation of our previous CPR. From the additional data obtained from Well Shaikan-10A and Well Shaikan-11 and from recent production data and material balance modelling (Section 5.10) we have concluded that a narrower range of uncertainty in fracture porosity is appropriate and therefore used 0.2%, 0.4% and 0.7% as low, mid and high case estimates.

The available fracture data for the Cretaceous and Triassic are more limited than for the Jurassic, and therefore there is greater uncertainty in estimates of fracture porosity for these intervals than for the Jurassic. Image logs suggest that the Cretaceous and Triassic might have a lower fracture density than the Jurassic and therefore we have reflected this, together with consideration of the geological aspects of each interval, in our estimated ranges of fracture porosity. For the Cretaceous interval, we have used 0.05%, 0.3% and 0.7% for the low, mid and high cases. For the Triassic interval, we have used 0.1%, 0.3% and 0.7% for the low, mid and high case estimates.

Fracture porosity estimates described in this section are applicable to net reservoir only. Net-to-gross ratios for fractures were estimated by identifying poorly fractured rock such as shale and anhydrite and defining any interval of rock containing more than 50% shale or 50% anhydrite as non-net.

5.5. Log Analysis

The composited wireline log data for Wells Shaikan-5B and Shaikan-8 were provided by GKP in digital format, and include curves containing total gamma ray, thorium, potassium and uranium components from the spectral gamma, caliper, deep, shallow and micro resistivity, density, neutron sonic, and NMR logs. GKP also provided ERCE with interpreted logs comprising shale volume, porosity and water saturation, as well as the average reservoir properties derived from these interpretations by GKP.

ERCE analysed the wireline logs for these two wells and calculated shale volume, porosity and water saturation. The ERCE interpretations were used as a basis for auditing the log analysis provided by GKP, from which property values and ranges of uncertainty were estimated for volumetric calculations. The interpreted logs for Well Shaikan-5B are shown in Figure 5.5.

5.5.1. Shale Volume

ERCE derived shale volume (Vsh) from the gamma ray and density and neutron logs. Where the spectral gamma was available, the value that excludes the uranium contribution was used, and the linear gamma ray index was calculated. The density neutron method was also used to calculate Vsh and where the hole was in gauge the minimum value for Vsh estimated using the two methods was accepted. Where the hole was out of gauge, the gamma ray index method was used.

5.5.2. Porosity

ERCE derived total porosity from the density neutron cross plot method where the hole was in gauge. Where the hole was over gauge the sonic porosity was used if it was lower than the density neutron porosity. Core poroperm data were available over the interval 1,936.3 to 1,947.4 mMDRKB in Well Shaikan-5B. There is generally only moderate agreement with the density neutron porosity here, but this may be in part explained by core grain densities. More than half of the core plugs show laboratory derived grain density below 2.71 g/cc, the textbook value for limestone. The mudlog showed the Alan formation over the cored interval to be composed of limestone with minor discrete shale bands. Assuming that the plugs have not been taken from the shaley bands, this implies that sample cleaning may not have removed all of the residual hydrocarbon, and in consequence the derived porosity will be too low. This is consistent with the separation between the total gamma reading and the Potassium/Thorium contribution over this interval. The separation is probably due to the contribution from Uranium bearing organic material. This separation is significant over the Alan formation, but is much less so over the predominantly clean limestone of the Mus formation.

ERCE calculated effective porosity using:

$$\emptyset_e = \emptyset_t(1 - V_{sh})$$

where: $\emptyset_e$ = effective porosity
$\emptyset_t$ = total porosity
V_{sh} = Shale volume

5.5.3. Water Saturation

ERCE used the Archie equation to calculate water saturation:

$${S_w}^n = FF \times \frac{R_w}{R_t}$$

$$FF = \frac{a}{\emptyset^m}$$

where: FF = formation factor
R_w = formation water resistivity (ohm.m)
R_t = resistivity log value (ohm.m)

$\emptyset$ = porosity log value
a = Archie constant (= 1)
m = cementation exponent
n = saturation exponent

Special core analysis gave values of m=1.86 and n=1.95 for the Sargelu, and Alan formations. Other SCAL measurements gave m=1.90 for the Mus Formation, and m=2.04 for the Butmah Formation. For both these formations a value of 2 was used for "n". For other formations, saturation was calculated using "m"=2 and "n"=2.

ERCE calculated formation temperature with the formula:

$$T = 27 + 0.02 \times D$$

where: T = Temperature (°C)
D = Depth (mTVDRKB)

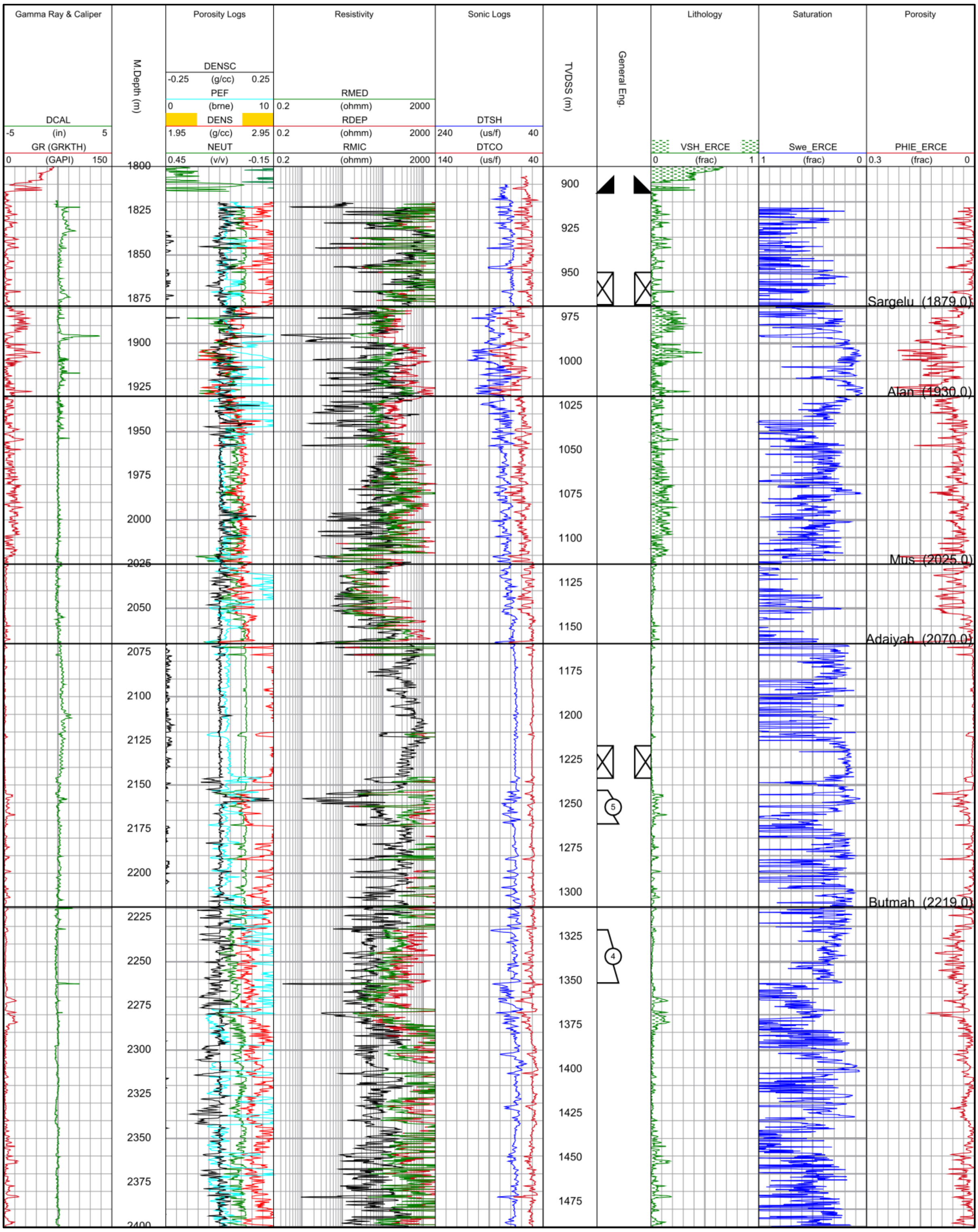
Rw was reported to be 0.7 ohm.m @ 15.5° C in the Sarmord and Chia Gara formations, equivalent to approximately 10,000 ppm NaCl. In the Jurassic Barsarin-Mus Formation, a value of 0.45 ohm.m @ 15.5° C was used, equivalent to approximately 16,000 ppm NaCl. In the lower Jurassic Adaiyah – Baluti formations, and Upper Triassic Kurre Chine A & B formations, Rw was 0.3 ohm.m, equivalent to approximately 25,000 ppm NaCl. In the Triassic Kurre Chine C, Rw was 0.053 ohm.m, equivalent to approximately 205,000 ppm NaCl.

5.5.4. Cut-offs

We carried out our petrophysical interpretation on two representative wells to provide a basis for auditing the reservoir property ranges provided by GKP. From our analysis, we concluded that the property ranges provided by GKP were satisfactory and these were consequently used by ERCE for making our volumetric estimates. For estimating N/G, porosity cut-offs of 7.0%, 4.5% and 3.0% were applied for the low, best and high cases. Low, best and high porosity cut-offs lead to low, best and high estimates of hydrocarbon pore thickness, with the constituent reservoir properties N/G ratio, porosity and oil saturation. The field-wide averages of N/G, porosity and saturation estimates included data from all wells where log data were available.

5.6. Fluid Contacts

There is uncertainty in fluid contacts in the Jurassic reservoirs of the Shaikan field. Several sources of data were analysed to identify the contacts and estimate the range of uncertainty in contact depths. These include the analysis of oil and water pressure gradients, the distinction between oil and water producing zones from DST data, analysis of wireline logs, inspection of fluid content of recovered cores and indications of fluids while drilling. Figure 5.5 shows an illustrative cross section through the Shaikan field.



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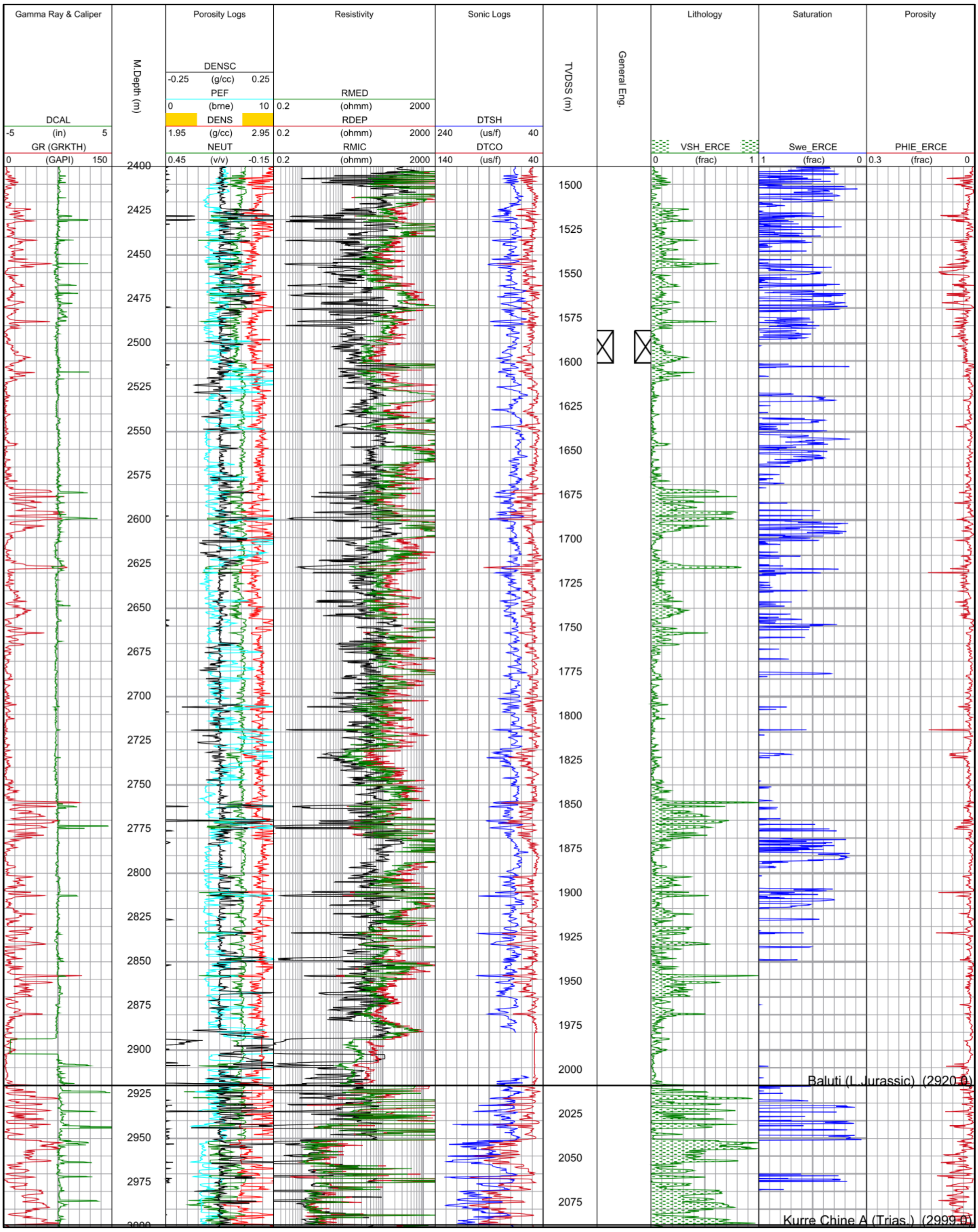

Figure 5.4: Well Shaikan-5B CPI of Jurassic Interval

Well Sheikh Adi-3C (SA-3C) was drilled within the Shaikan licence block in the saddle between Shaikan and the neighbouring Sheikh Adi field. The well was completed with downhole pressure gauges and used as an observation well. Recorded data show pressure decline closely tracking recorded pressures in the Shaikan field. This is interpreted to demonstrate hydraulic continuity in the Jurassic reservoirs between Shaikan and the footwall of Sheikh Adi. We have therefore assumed the same fluid contacts in the Jurassic in Shaikan and the footwall of Sheikh Adi based on the interpretation that the Sheikh Adi fault delimits the extent of the accumulation in the Jurassic. This is illustrated in Figure 5.5. Due to the structural relationship of the formations, it has further been assumed that continuity between Shaikan and Sheikh Adi also occurs in the Cretaceous reservoirs, whilst this is not necessarily the case for the Triassic reservoirs.

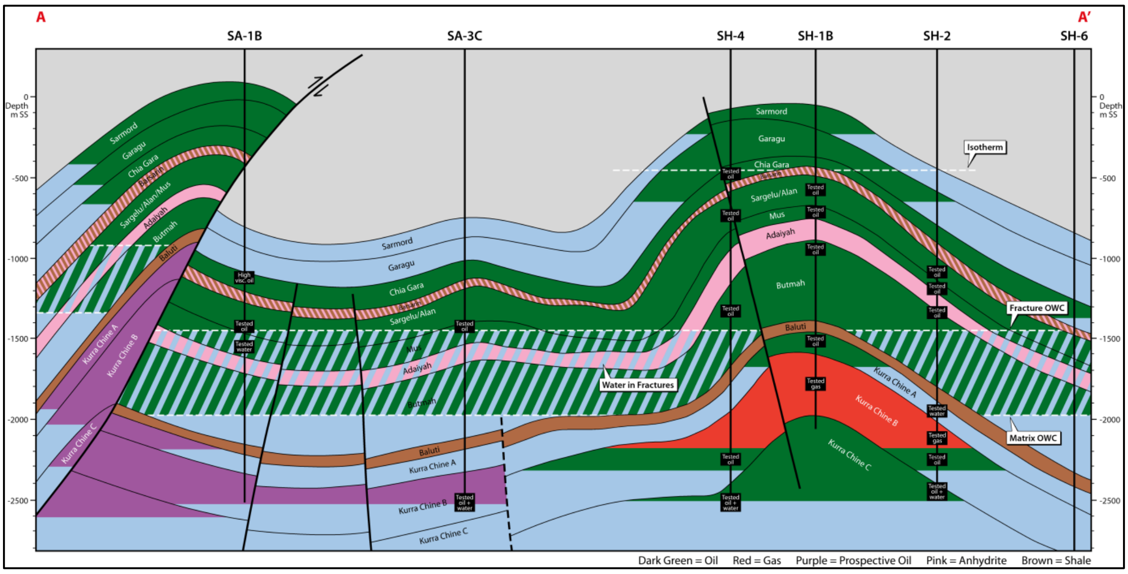

Figure 5.5: Illustrative Cross Section through Shaikan and Sheikh Adi Fields

It should be noted that there is uncertainty regarding the depth intervals from which fluids flowed during the flow tests and hence there is uncertainty in the interpretation of fluid contacts based on flow tests. Casing (or tubing) inserted into the well over intervals to be tested was (generally) not cemented in place, as cement would have penetrated the fractures and blocked the flow of fluids. Zone isolation was in the form of packers placed externally to the casing above and below the zone to be tested. The casing was then perforated, providing access directly to the formation across the perforations, but also to the formation behind casing via the annulus above and below the perforated interval as far as the external packers and, in the event of the formation being extensively fractured, to the formation above and below the packers via the fractures. Due to the low permeability of the matrix, flow of oil and water during testing was most likely to have come from fractures, and therefore the test results have been used to define the fluid contacts in the fractures only.

Another consideration in the analysis was whether or not a primary gas cap exists in the Shaikan field. Based on the field pressure gradient and PVT analysis, it is possible that a primary gas cap exists at the top of the structure. However, there is uncertainty in the PVT analysis where the bubble point measurements range from 1,570 psia to 1,907 psia. In addition, the reservoir temperature decreases when moving up-dip from measured data points. For the purposes of this evaluation, we have assumed that a small primary gas cap exists.

5.6.1. Cretaceous

Within the Cretaceous (Sarmord, Garagu and Chia Gara formations), a distinction was made between highly viscous oil at shallow depth, which is considered to be biodegraded and immobile unless heated, and oil at greater depth, which appears to have sufficiently low viscosity to flow under pressure drawdown. We have estimated in place volumes for both the shallow biodegraded oil and the deeper lower viscosity oil, but we have reported recoverable volumes only for the deeper zone of lower viscosity. The point of transition between viscous and moveable oil is likely to be related to temperature. However, there were insufficient reliable data from which to construct a temperature model of the reservoir to identify the depth of the isotherm at which this transition takes place. Consequently, the flow test results have been used to estimate this depth, which is for convenience referred to as the 'isotherm' depth.

Three attempts were made to flow test the Garagu formation in Well Shaikan-3, with perforations open between 290 mTVDSS and 410 mTVDSS in DST-1, DST-1A and DST-2A. These tests resulted in the down hole tools becoming clogged with viscous, sticky hydrocarbons. For the high case estimate, ERCE used the base of the Garagu formation tested by Well Shaikan-3 (DST-2A), at approximately 390 mTVDSS for the isotherm. DST-7 in Well Shaikan-4 was a successful test of the Chia Gara formation that flowed 130 stb/d of oil and 10 bbl/d of water from perforations over the interval 525 to 542 mTVDSS. We used the deepest perforation in Well Shaikan-4 DST-7 in the Chia Gara at approximately 540 mTVDSS for the isotherm in the low case. We assumed the most likely depth of the isotherm to occur 1/3 of the distance from the deep to shallow depths, i.e. at 490 mTVDSS.

ERCE analysed wireline logs, supported by DST results, to identify oil down to (ODT) and water up to (WUT) depths in each of the Cretaceous reservoirs. These are;

Sarmord ODT (wireline logs):	220 mTVDSS (Well Shaikan-8)
Sarmord WUT (wireline logs):	250 mTVDSS (Well Shaikan-5B)
Garagu ODT (wireline logs):	398 mTVDSS (Well Shaikan-3)
Garagu WUT (wireline logs):	1,120 mTVDSS (Well Shaikan-6)
Chia Gara ODT (test):	1,390 mTVDSS (Well Shaikan-6)

The ODT and WUT depths were used to define the low case and high case estimates of oil water contact (OWC), apart from the Chia Gara where a single value of 1,390 mTVDSS was used for all cases. In the Sarmord the best case was defined by a simple arithmetic average, while in the Garagu, due to the wide range in values, a log normal approach was used.

5.6.2. Jurassic

The Jurassic comprises the Barsarin, Sargelu, Alan, Mus, Adaiyah and Butmah formations, all of which contain oil apart from the Barsarin, which is considered non-reservoir. Pressure data acquired during a comprehensive campaign of flow testing suggest that the oil accumulation is continuous across all the formations of the Jurassic interval and hence fluid contacts are common to all formations. However, for volumetric estimation purposes, distinctions were made between oil occurring in the fractures and in the matrix and between clearly mobile oil and highly viscous oil in the fractures (referred to as the 'high viscosity zone'). ERCE has therefore assigned multiple sets of fluid contacts, fluid properties and recovery factors to the Jurassic accumulations according to oil quality and to whether the oil is in the fractures or the matrix.

The general model for the Jurassic interval comprises moveable oil in the fractures down to a depth of approximately 1,350 mTVDSS, below which an interval with highly viscous oil, the high viscosity zone, extends to approximately 1,450 mTVDSS. Below this depth, the fractures appear to be water bearing. However, oil has been identified in the matrix all the way down to approximately 1,950 mTVDSS. This apparent anomaly, in which water occurs in fractures surrounding oil saturated blocks of matrix (between approximately 1,450 and 1,950 mTVDSS) could be explained by possible updip leakage of the oil from the structure in recent geological time, causing drainage of the fractures accompanied by influx of water from the aquifer. It is possible that the influx of fresh water caused degradation of the oil to form an interval in the fractures of highly viscous oil or tar. Details are described below.

The log and core data from Well Shaikan-6 indicate an OWC in the matrix at 1,975 mTVDSS. Cores above this depth show high saturations of oil and oozing of oil upon release of pressure at surface. We have consequently used a depth of 1,975 mTVDSS for the OWC in the matrix for the low, best and high cases.

The OWC in the fractures (i.e. the contact between free water and the highly viscous oil in the fractures) has been estimated at 1,450 mTVDSS for the low, best and high cases. This is constrained by the results of Well Shaikan-6 DST-5A, which flowed water at a rate of 1,100 bbl/d with small amounts of heavy oil from the Sargelu formation that was perforated from 1,471 to 1,491 mTVDSS, suggesting a WUT at 1,471 mTVDSS.

Oil has been tested down to a depth estimated to be somewhere between 1,350 and 1,400 mTVDSS in the Jurassic, but no oil has been recovered in a successful flow test from the Jurassic below this. The deepest test that flowed oil at good rates from the Jurassic is DST-8 in Well Shaikan-2, which was perforated in the Butmah from 1,329 to 1,345 mTVDSS and flowed 723 stb/d of oil and 38 bbl/d of water. The depth at which the transition from medium to high viscosity oil in the fractures occurs has therefore been assumed to be 5 m below this depth, at approximately 1,350 mTVDSS. We have used 1,350 mTVDSS for the low best and high cases.

Heavy, tar-like oil was recovered from DST-7 in Well Shaikan-2 between 1,370 and 1,376 mTVDSS and water and tar-like heavy oil was recovered from DST-6 in the same well between 1,397 and 1,407 mTVDSS, defining the high viscosity zone.

Pressure data obtained from the many DSTs carried out by GKP have been used to estimate the formation pressure as a function of depth. These have been used to estimate the free water level (FWL), interpreted as the depth at which the oil pressure trend intersects the water pressure trend. Both absolute pressure and excess pressure plots have been analysed (Figure 5.8 and Figure 5.9). Due to the inherent difficulty of defining a precise relationship between pressure and depth from well test information, there is much scatter in the data points. However, the plots indicate a FWL somewhere between 1,350 mTVDSS and 1,450 mTVDSS. We have used a depth of 1,450 mTVDSS for the OWC in the fractures in the low, best and high cases.

Test results from Well Shaikan-5B appear to contradict the selection of contacts described above, in that clean water flowed from the Butmah formation that was perforated from 1,321 to 1,351 mTVDSS in DST-4. GKP has explained this by noting that the swell packer was located some 241 m deeper than the deepest perforation, i.e. at 1,592 mTVDSS, considerably below the OWC in the fractures at 1,450 mTVDSS, resulting in a direct route behind casing between the perforations and an extensively fractured interval below the OWC. We agree that this is possible as the high density of the oil and very low viscosity of the water would allow water production via the annulus with little pressure drawdown on the well.

The recent pressure response recorded at well Sheikh Adi-3C in the Jurassic indicated it is connected to and forms part of the Shaikan field, and therefore the Shaikan Jurassic contacts have been extended into the Sheikh Adi Block. The natural geological break between the Shaikan and Sheikh Adi fields is assumed to be the main fault of Sheikh Adi structure.

We have estimated a depth of 488 mTVDSS as the greatest depth at which a primary GOC could exist, based on extrapolation of saturation pressure from PVT analyses and consideration of the intervals that were flow tested, none of which showed free flowing gas. We have used 488 mTVDSS for the low case. For the high case, we have assumed that no primary gas cap exists. For the best case, we have assumed that the GRV occupied by gas is equal to half of that in the low case.

5.6.3. Triassic

The Triassic interval comprises the Kurre Chine A, B and C formations, in which separate hydrocarbon accumulations were intersected. The oil in the Triassic is significantly lighter than the oil encountered in the Jurassic, with low viscosity (less than 0.5 cp). The Kurre Chine A is a relatively small light oil accumulation. The Kurre Chine B can be divided into an upper and a lower part, possibly separated by a seal. Fluids recovered during testing suggest that gas was discovered in the shallower part of the Upper Kurre Chine B with oil deeper in the Upper Kurre Chine B and in the Lower Kurre Chine B. The Kurre Chine C is the deepest interval in which hydrocarbons have been positively tested in the Shaikan field. Hydrocarbons in the Kurre Chine C appear to be a light oil. A few wells have penetrated the deeper Kurre Chine dolomites, which showed inconclusive evidence of containing hydrocarbons, possibly gas. However, the Kurre Chine dolomites have not been appraised and no resources have been attributed to them in this report.

Triassic Kurre Chine A: GKP has used an OWC of 1,680 mTVDSS for the Kurre Chine A. This is fairly reliably supported by extrapolation of the pressures recorded during DST-4 of Well Shaikan-1B onto a regional water line. ERCE has used this as the best case. DST-4 of Well Shaikan-1B tested dry oil at a rate of 1,784 stb/d over an interval from 1,518 to 1,598 mTVDSS. ERCE used a depth of 1,640 mTVDSS, approximately midway between the greatest depth of the interval from which dry oil flowed (1,598 mTVDSS) and the best case OWC of 1,680 mTVDSS for the low case OWC. ERCE used 1,720 mTVDSS for the high case OWC, resulting in a symmetric distribution. DST-5 of Well Shaikan-2 flowed water from an interval between 1,856 and 1,964 mTVDSS and DST-3 of Well Shaikan-4 flowed water from an interval from 1,969 to 1,984 mTVDSS. Pressures from these two water tests confirm the regional water gradient. The same set of contacts was used for the fractures and the matrix.

Triassic Kurre Chine B: Two alternative interpretations of the dataset for the Kurre Chine B lead to two different reservoir models. In the first model, the KCB Upper and KCB Lower are in pressure communication with an oil accumulation and gas cap and fluid contacts that are common to both intervals. In the second model, the KCB Upper and KCB lower are separated by a seal, with different pressures and fluid contacts. In this model, KCB Upper is an oil accumulation with a gas cap, while

KCB lower is an oil accumulation which may not have a gas cap. Data were insufficient to conclusively eliminate either one of these models. ERCE adopted the first model on the basis that the pressure measurements more strongly support a single continuous accumulation of oil with a gas cap. This model leads to more conservative estimates of Resources than the alternative model.

We defined the depth to the gas oil contact (GOC) by analysing test results. Well Shaikan-1B tested gas in DST-5 from an interval between 1,755 and 1,775 mTVDSS and Well Shaikan-2 tested gas in DST-4A from an interval between 2,121 and 2,127 mTVDSS, both in the KCB Upper. The greatest depth in an interval from which gas flowed was therefore 2,127 mTVDSS. This was defined as a gas down to (GDT) and was used for the high case GOC. Well Shaikan-4 DST-2 flowed oil at a rate of 5,086 stb/d from an interval between 2,234 and 2,254 mTVDSS in the KCB Lower. The shallowest depth of an interval from which oil flowed was therefore 2,234 mTVDSS. This was defined as an oil up to (OUT) and used by ERCE for the low case GOC. We set the best case GOC at 2,180 mTVDSS, half way between the low and high case GOCs. Oil was also tested in Well Shaikan-2, DST4, which flowed 2,620 stb/d from a KCB lower interval between 2,288 and 2,297 mTVDSS and Well Shaikan-5B DST 3, which flowed 600 stb/d from a KCB lower interval between 2,290 and 2,302 mTVDSS. The greatest depth of an interval from which oil flowed was therefore 2,302 mTVDSS, defined as an ODT and used by ERCE for the low case OWC. Water was tested from greater depths: Well Shaikan-6 DST-2 flowed water between 2,700 and 2,710 mTVDSS and Well Shaikan-6 DST-1 flowed water between 2,817 and 2,850 mTVDSS.

Extrapolation of pressures obtained from all these tests suggest that the greatest reasonable depth for an OWC is approximately 2,410 mTVDSS (described in Section 5.9.1) and we used this for the high case. GKP used a depth of 2,325 mTVDSS for the most likely OWC, approximately 25% of the depth difference between the low and high case OWCs. This is reasonable and was used by ERCE for the best case.

Triassic Kurre Chine C: Well Shaikan-2 tested oil at a rate of 1,000 stb/d and water at a rate of 900 bbl/d from an interval open between 2,426 and 2,506 mTVDSS. We have consequently set the low and best case OWCs at 2,426 and 2,506 mTVDSS respectively.

Well Shaikan-4 DST-1A tested oil at a rate of 440 stb/d with water at a rate of 68 bbl/d in a barefoot test from 2,324 to 2,611 mTVDSS. The well was tested with a fish in the hole, up to 2,508 mTVDSS. A production logging tool (PLT) showed that gas with some oil was flowing around the fish from below, but it was not clear what the hydrocarbon type was, nor which formation it was coming from, although it did suggest that hydrocarbons might exist below the depth of the best case OWC. A single pressure point obtained from this test was extrapolated to the regional water gradient, giving an estimate to the OWC at 2,947 mTVDSS. However, the extrapolation is tenuous and confidence in this depth as an OWC is much less and consequently we have used this depth to define the high case OWC.

5.7. Gross Rock Volume Estimation

5.7.1. Cretaceous

The structural depth map to the top of the Cretaceous Sarmord formation described in Section 5.2 was used by ERCE to generate structural depth maps to the tops of the Garagu and Chia Gara formations using formation isochores derived from the wells. The formational isochore maps were adjusted to account for the structural thickening seen in Well Shaikan-10A and Well Shaikan-11.

ERCE estimated a range of gross rock volume (GRV) for each Cretaceous interval using the uncertainty ranges of OWCs described in Section 5.5.1. GRVs and STOIIPs were estimated for the region both above and below the isotherm separating viscous immobile oil from the deeper, mobile oil. However, ERCE has reported Contingent Resources only for the oil below the isotherm. Since the entire Sarmord formation lies above the isotherm, no Contingent Resources have been reported for this formation.

5.7.2. Jurassic

A Top Barsarin structural depth map was used by ERCE to generate structural depth maps for each Jurassic reservoir interval using formation isochores derived from the wells, in the same manner described above for the Cretaceous. ERCE estimated ranges of GRVs for the Jurassic interval for the different zones and OWCs as described in Section 5.5.2.

5.7.3. Triassic

A top Triassic Kurre Chine A structural depth map was generated using the newly reprocessed PoSDM data, as described in Section 5.2. However, the Kurre Chine is poorly imaged in places on this new seismic data, with better imaging seen on the older volume. Rather than entirely superseding the original, the new Top Kurre Chine surface is therefore considered to represent an alternative structural possibility. The new surface, which gives larger GRVs, was therefore used with the high case contacts, as described in Section 5.5.3, to construct the high case GRV. The low case GRV was calculated using horizons derived from the old seismic data, with the low case contacts. In both cases, depth maps for the Kurre Chine B and C were created by the addition of true stratigraphic thickness isopachs derived from the wells, in the same manner described for the Jurassic and Cretaceous reservoir sections above. The mid case GRV was derived from the low and the high cases, assuming a lognormal distribution.

5.8. Reservoir Fluid Properties

GKP has collected many bottom hole and surface samples of oil and gas and has sent them to specialist laboratories for PVT analysis. Summaries of the PVT results used in the preparation of this report are shown in Table 5.1 for the Jurassic oil, Table 5.2 for the Triassic oil and Table 5.3 for the Triassic gas. ERCE has used the PVT data to estimate oil formation volume factors and solution gas oil ratios for oil zones and gas expansion factors and condensate-gas ratios for gas zones, as well as the uncertainty ranges in these properties for the purposes of estimating volumes of hydrocarbons in place. In instances where no PVT reports were available, we estimated fluid properties from an understanding of the test results. In the Cretaceous interval, the oil is very heavy or bituminous in nature and no PVT analysis has been reported. In the Jurassic interval the oil is medium to heavy with a gravity of between 14 and 20 °API and relatively high in-situ viscosity. In the Triassic interval, hydrocarbons are light oil, with a gravity of between 38 and 43 °API, and gas. The oil contained within all intervals of the field has a high content of H_2S and CO_2.

Table 5.1: Shaikan Jurassic Oil PVT Summary

Measurement/entity	Units	SH-1B Sargelu	SH-1B Mus	SH-1B Butmah	SH-1B Sargelu/ Alan	SH-3 Sargelu/ Alan	SH-2 Alan	SH-2 Mus
DST number		1	2	7	(Note 1)	3A	1	8
Sample type(Note 2)		Rec.	Rec.	BH	BH	BH	BH	BH
Top perforations	mMDRKB	1,451	1,627	1,790	1,470	1,303	1,792	2,040
Base perforations	mMDRKB	1,510	1,668	1,815	1,540	1,513	1,836	2,058
Mid perforation depth	mTVDSS	599	763	917	621	631	1,113	1,337
Reservoir pressure	psia	1,989	2,175	2,279	1,990	2,162	2,588	2,871
Reservoir temperature	°F	119	129	128	119	120	142	149
Saturation pressure	psia	172	330	1,818	1,838	1,907	1,570	1,272
Density at reservoir	g/cc	0.914	0.924	0.860	0.856	0.859	0.883	0.904
Density at standard conditions	g/cc	0.935	0.955	0.946	0.939	0.942	0.961	0.972
Density at standard conditions	°API	19.9	16.7	18.1	19.2	18.7	15.7	14.0
Viscosity at reservoir	cp	57.70	81.70	13.52	11.41	9.85	26.25	55.88
GOR	scf/stb	57	52	413	442	480	325	240
FVF at reservoir	rb/stb	1.044	1.042	1.208	1.208	1.225	1.159	1.150
Compressibility at reservoir	10^{-6} psi^{-1}	4.9	4.7	7.1	7.8	7.4	6.4	5.6
Solution gas non HC content	mol %	23.6	23.8	19.7		25.2	21.3	22.7

Notes

1) The Sargelu/Alan sample from Well Shaikan—1B was taken while the completion was being run.

2) ‘Rec.’ means recombined. ‘BH’ means bottom hole.

Table 5.2: Shaikan Triassic Oil PVT Summary

Measurement/entity	Units	SH-1B Kurre Chine A	SH-2 Kurre Chine B	SH-4 Kurre Chine B	SH-2 Kurre Chine C
DST number		4	4	2	3
Sample type(Note 2)		Rec.	BH		Rec.
Top perforations	mMDRKB	2,402	3,057	3,010	3,195
Base perforations	mMDRKB	2,483	3,066	3,030	3,275
Mid perforation depth	mTVDSS	1,558	2,292	2,244	2,466
Reservoir pressure	psia	3,254	4,444	4,191	6,015
Reservoir temperature	°F	151	185	183	186
Saturation pressure	psia	2,555	4,163	4,098	4,668
Density at reservoir	g/cc	0.657	0.585	0.638	0.608
Density at standard conditions	g/cc	0.810	0.819	0.840	0.833
Density at standard conditions	°API	43.2	41.2	37.1	38.3
Viscosity at reservoir	cp	0.32	0.14	0.19	0.19
GOR	scf/stb	1,086	2,647	1,719	1,873
FVF at reservoir	rb/stb	1.579	2.363	1.858	1.965
Compressibility at reservoir	10^{-6} psi^{-1}	16.6	32.92		17.8
Solution gas non HC content	mol %	14.3	27.94		9.7

Notes

1) Limited data are available for Well Shaikan-4 DST-2. Information reported here is from GKP's FDP report.

2) 'Rec.' means recombined. 'BH' means bottom hole.

Table 5.3: Shaikan Triassic Gas PVT Summary

Measurement/entity	Units	SH-2 Kurre Chine B
DST number		4A
Sample type		recombined
Top perforations	mMDRKB	2,882
Base perforations	mMDRKB	2,888
Mid perforation depth	mTVDSS	2,124
Reservoir pressure	psia	4,191
Reservoir temperature	°F	178
Saturation pressure (dew point)	psia	4,191
Density at reservoir conditions	g/cc	0.421
Condensate density at standard conditions	g/cc	0.775
Condensate density at standard conditions	°API	51.1
Viscosity at reservoir conditions	cp	0.08
CGR	stb/MMscf	120
Z factor at reservoir conditions	dimensionless	0.826
Expansion factor from reservoir conditions	scf/rcf	281

5.8.1. Cretaceous

For all of the Cretaceous formations, we used a formation volume factor (FVF) of 1.0 rb/stb for both the shallow, highly viscous and immobile oil and for the deeper, mobile oil in the fractures and in the matrix. No uncertainty range was applied to the FVF. We assumed that no gas would be liberated from the produced oil. No data were available to confirm these assumptions, but they are consistent with the known heavy nature of the oil.

5.8.2. Jurassic

We estimated the oil FVF for the Jurassic above the high viscosity zone from PVT reports of good quality oil samples. The arithmetic mean of the FVFs from reliable samples is 1.19 rb/stb. We used this value for the best case and applied an uncertainty range of approximately ±3% to give low, best and high case values of 1.22 rb/stb, 1.19 rb/stb and 1.16 rb/stb. This range was applied to the oil in all the Jurassic formations in the fractures and in the matrix down to the top of the high viscosity zone. For the high viscosity zone in the fractures we used a FVF of 1.00 rb/stb for low, best and high cases. No PVT data were available to support this value but it is consistent with the heavy nature of the oil. In the case of the matrix, the oil between the top of the high viscosity zone in the fractures and the OWC in the matrix at 1,975 mTVDSS, was assigned a range of FVFs of 1.10, 1.05 and 1.00 rb/stb for the low, best and high cases. No data were available to support these values but the oil is known to be heavier than the shallower oil in the matrix and hence should have lower values for the FVF.

We have used a value for the GOR of 390 scf/stb for oil in all Jurassic formations in both the matrix and fractures down to the top of the high viscosity zone for the best case and applied an uncertainty range of approximately ±10%. For the oil in the fractures in the high viscosity zone we have not attributed any solution gas. In the case of the matrix, GKP used a GOR value of 200 scf/stb for the oil between the top of the high viscosity zone in the fractures and the OWC in the matrix at 1,975 mTVDSS. No data were available to support this value, but it appears reasonable considering the nature of the oil discovered while drilling, coring and attempting flow testing. We used this for the best case and applied an uncertainty range of ±10%.

5.8.3. Triassic

Triassic Kurre Chine A: ERCE used the results of PVT laboratory experiments carried out on oil samples collected during DST-4 of Well Shaikan-1B to define properties for volumetric estimation. The laboratory derived oil formation volume factor of 1.58 rb/stb was used for the best case input and an uncertainty range of ±5% was applied. The laboratory derived gas oil ratio of 1,086 scf/stb was used for the best case with a ±10% uncertainty range. The non-hydrocarbon fraction of the solution gas was estimated to be approximately 14 % (molar).

Triassic Kurre Chine B: Two sets of samples were recovered from the gas cap, during DST-5 of Well Shaikan-1B and during DST-4A of Well Shaikan-2. When Well Shaikan-1B was tested, the wellbore was open to both the gas cap in the KCB, from 1,951 to 1,961 mTVDSS and a deeper oil bearing zone. Therefore, the PVT analysis of the samples from this test, which shows a very high condensate gas ratio (CGR), is probably not representative. Samples were recovered during DST-4A from Well Shaikan-2. The sample that was analysed in the laboratory was reported to exhibit dew point characteristics, i.e. it is likely to be in the gas phase at reservoir conditions. There is considerable uncertainty regarding the CGR, both in terms of fluid sampling representativeness and also as separator conditions are not yet defined. ERCE has used a range from 108 to 180 stb/MMscf for volumetric purposes, with a mid case estimate of 120 stb/MMscf. The range of gas expansion factors was estimated to be 238, 250 and 263 scf/rcf for the low, best and high cases. The dry gas is expected to contain approximately 29% (molar) of non-hydrocarbons (primarily H_2S and CO_2). These non-hydrocarbon gas volumes were removed from the estimated recoverable gas volumes before reporting.

For the oil interval in the KCB, ERCE used PVT analyses from DST-4 of Well Shaikan-2 and DST-4 of Well Shaikan-4. We selected a range for the oil formation volume factor of 2.33, 2.12 and 1.91 rb/stb for the low, best and high cases with a corresponding range in GOR of 1,856, 2,183 and 2,510 scf/stb. We estimated that approximately 28% (molar) of the solution gas comprises non-hydrocarbon components.

Triassic Kurre Chine C: Fluid samples from Well Shaikan-4 DST-1A show very high gas content and have not been used by ERCE. An oil sample obtained from Well Shaikan-2 during DST-3 was analysed in a PVT laboratory and the results have been used to estimate fluid properties. We used the laboratory derived oil formation factor of 1.97 rb/stb to define the best case value and applied a ±10% uncertainty range. Likewise, the laboratory derived GOR of 1,873 scf/stb was used to define the best case value, with a ±15% uncertainty range. The solution gas was estimated to contain approximately 10% (molar) of non-hydrocarbon components, which have been removed before reporting of volumes.

5.9. Volumetric Input Parameters

Details of the ranges of parameters used by ERCE for estimating STOIIP and GIIP for each reservoir interval are shown in Table 5.4 for the Cretaceous, Table 5.5 for the Jurassic and Table 5.6 for the Triassic formations. These parameters were used as input into the probability distribution functions for estimating Contingent Resources as described in Section 5.10. For fractures, we applied the fracture porosity ranges described in Section 5.3.2 to the net rock volume.

Table 5.4: Volumetric Input Parameters for Shaikan Cretaceous

Property	Sarmord			Garagu			Chia Gara		
	Low	Best	High	Low	Best	High	Low	Best	High
Matrix									
GRV (10^6 m^3)	3,160	3,393	3,629	5,308	12,229	23,711	20,141	20,141	20,141
N/G (fraction)	0.090	0.121	0.134	0.025	0.028	0.028	0.060	0.068	0.069
Phi (fraction)	0.141	0.114	0.102	0.159	0.151	0.150	0.133	0.125	0.125
So (fraction)	0.654	0.639	0.634	0.515	0.511	0.510	0.650	0.642	0.641
Bo (rb/stb)	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Fractures									
GRV (10^6 m^3)	3,160	3,393	3,629	5,308	12,229	23,711	20,141	20,141	20,141
N/G (fraction)	0.720	0.720	0.720	0.560	0.560	0.560	0.310	0.310	0.310
Phi (fraction)	0.0005	0.0030	0.0070	0.0005	0.0030	0.0070	0.0005	0.0030	0.0070
So (fraction)	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
Bo (rb/stb)	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00

Notes

1) GRV estimates in this table are above and below the isotherm depth at which oil becomes mobile.
2) No recoverable volumes are reported for the Sarmord formation as the entire reservoir interval lies above the isotherm depth.

Table 5.5: Volumetric Input Parameters for Shaikan Jurassic Oil

Property	Sargelu			Alan			Mus			Adaiyah			Butmah		
	Low	Best	High	Low	Best	High	Low	Best	High	Low	Best	High	Low	Best	High
Matrix															
GRV (10^6 m^3)	14,386	14,724	15,062	17,083	17,102	17,120	8,810	8,810	8,810	16,049	16,049	16,049	59,632	59,632	59,632
N/G (fraction)	0.028	0.042	0.064	0.131	0.204	0.271	0.240	0.301	0.344	0.028	0.054	0.075	0.056	0.114	0.159
Phi (fraction)	0.095	0.078	0.066	0.127	0.093	0.080	0.126	0.115	0.106	0.095	0.078	0.068	0.102	0.080	0.075
So (fraction)	0.691	0.671	0.665	0.652	0.655	0.653	0.605	0.602	0.601	0.712	0.724	0.714	0.660	0.651	0.643
Bo (rb/stb)	1.22/1.10	1.19/1.05	1.16/1.00	1.22/1.10	1.19/1.05	1.16/1.00	1.22/1.10	1.19/1.05	1.16/1.00	1.22/1.10	1.19/1.05	1.16/1.00	1.22/1.10	1.19/1.05	1.16/1.00
Fractures															
GRV (10^6 m^3)	10,937	11,275	11,613	11,580	11,599	11,617	5,613	5,613	5,613	9,030	9,030	9,030	22,263	22,263	22,263
N/G (fraction)	0.530	0.530	0.530	0.970	0.970	0.970	0.970	0.970	0.970	0.200	0.200	0.200	0.860	0.860	0.860
Phi (fraction)	0.0020	0.0040	0.0070	0.0020	0.0040	0.0070	0.0020	0.0040	0.0070	0.0020	0.0040	0.0070	0.0020	0.0040	0.0070
So (fraction)	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
Bo (rb/stb)	1.22/1.00	1.19/1.00	1.16/1.00	1.22/1.00	1.19/1.00	1.16/1.00	1.22/1.00	1.19/1.00	1.16/1.00	1.22/1.00	1.19/1.00	1.16/1.00	1.22/1.00	1.19/1.00	1.16/1.00

Notes

1) GRVs reported in this table include oil in the fractures above and below the depth at which the transition from highly viscous oil to less viscous oil takes place (1,350 mTVDSS) down to the OWC in the fractures (1,450 mTVDSS).
2) GRVs reported in this table include oil in the matrix down to the OWC in the matrix (1,975 mTVDSS) below the OWC in the fractures (1,450 mTVDSS).
3) For each case two values are reported for FVF. The low value applies to the region of high viscosity oil and vice versa.

Table 5.6: Volumetric Input Parameters for Shaikan Jurassic Gas Cap

Property	Sargelu			Alan		
	Low	Best	High	Low	Best	High
Matrix						
GRV (10^6 m^3)	676	338	0	37	19	0
N/G (fraction)	0.028	0.042	0.064	0.131	0.204	0.271
Phi (fraction)	0.095	0.078	0.066	0.127	0.093	0.080
So (fraction)	0.691	0.671	0.665	0.652	0.655	0.653
Eg (scf/rcf)	119	132	145	119	132	145
Fractures						
GRV (10^6 m^3)	676	338	0	37	19	0
N/G (fraction)	0.530	0.530	0.530	0.970	0.970	0.970
Phi (fraction)	0.0020	0.0040	0.0070	0.0020	0.0040	0.0070
So (fraction)	1.000	1.000	1.000	1.000	1.000	1.000
Eg (scf/rcf)	119	132	145	119	132	145

Notes

1) Gas volumes reported in this table are free gas in the gas cap and exclude solution gas in the oil leg.
2) Gas volumes reported in this table are wet gas volumes.
3) Gas volumes reported in this table include non-hydrocarbon components.

Table 5.7: Volumetric Input Parameters for Shaikan Triassic Oil

	Kurre Chine A			Kurre Chine B Oil			Kurre Chine C		
	Low	Best	High	Low	Best	High	Low	Best	High
Matrix									
GRV (10^6 m^3)	1,778	2,669	4,006	3,093	5,859	11,099	8,039	15,127	28,465
N/G (fraction)	0.032	0.125	0.197	0.060	0.122	0.170	0.035	0.053	0.073
Phi (fraction)	0.086	0.064	0.055	0.097	0.075	0.064	0.092	0.081	0.084
So (fraction)	0.698	0.659	0.647	0.709	0.699	0.683	0.731	0.687	0.708
Bo (rb/stb)	1.66	1.58	1.50	2.33	2.12	1.91	2.17	1.97	1.77
Fractures									
GRV (10^6 m^3)	1,778	2,669	4,006	3,093	5,859	11,099	8,039	15,127	28,465
N/G (fraction)	0.660	0.660	0.660	0.580	0.580	0.580	0.430	0.430	0.430
Phi (fraction)	0.0010	0.0030	0.0070	0.0010	0.0030	0.0070	0.0010	0.0030	0.0070
So (fraction)	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
Bo (rb/stb)	1.66	1.58	1.50	2.33	2.12	1.91	2.17	1.97	1.77

Table 5.8: Volumetric Input Parameters for Shaikan Triassic Gas Cap

	Kurre Chine B Gas		
	Low	Best	High
Matrix			
GRV (10^6 m^3)	21,495	15,816	11,638
N/G (fraction)	0.060	0.122	0.170
Phi (fraction)	0.0972	0.0754	0.0640
So (fraction)	0.709	0.699	0.683
Eg (scf/rcf)	238	250	263
Fractures			
GRV (10^6 m^3)	21,495	15,816	11,638
N/G (fraction)	0.580	0.580	0.580
Phi (fraction)	0.0010	0.0030	0.0070
So (fraction)	1.000	1.000	1.000
Eg (scf/rcf)	238	250	263

Notes

1) Gas volumes reported in this table are free gas in the gas cap and exclude solution gas in the oil leg.
2) Gas volumes reported in this table are wet gas volumes.
3) Gas volumes reported in this table include non-hydrocarbon components.

5.10. Dynamic Evaluation

The reservoir engineering dataset for the Shaikan field comprised a large number of DSTs carried out in all intervals in multiple wells and PVT laboratory reports for a comprehensive set of oil, gas and water samples. DST programmes in the Cretaceous have been hindered by mechanical difficulties and the bituminous nature of the oil, with the exception of Well Shaikan-4 which flowed oil at a rate of 130 stb/d from the Chia Gara formation during DST-7.

In the Jurassic many DSTs have been carried out successfully with oil flowing to surface from the Sargelu, Alan, Mus, Adaiyah, and Butmah formations, including a long term interference test between Wells Shaikan-1B and Shaikan-3. In some wells high flow rates were achieved from individual zones with little pressure drawdown, indicating high flow potential of the fracture system. However, several other DSTs failed to flow to surface or had low flow rates, due to low productivity and viscous oil, and in some cases due to mechanical problems. In the Triassic, several DSTs were conducted, flowing light oil and gas to surface, in some cases at high rates.

The Jurassic reservoirs have been on stream almost continuously since December 2013. Production has been primarily from the upper Jurassic with eight wells producing from these intervals and one well producing from the lower Jurassic. The nine production wells and two observation wells are fitted with downhole memory pressure gauges, providing invaluable reservoir information.

Special core analysis has been carried out on core plugs from Well Shaikan-2, Well Shaikan-4 and Well Shaikan-6. These included centrifuge air-brine capillary pressure measurements, gas-oil and water-oil relative permeability measurements and electrical measurements.

5.10.1. Well Tests and Interference Testing

Attempts to take Modular Formation Dynamic Tester (MDT) and Repeat Formation Tester (RFT) pressure measurements in Shaikan have been unsuccessful, due to the highly fractured nature of the reservoir rock. GKP has carried out an extensive DST programme, attempting approximately 47 DSTs at different intervals in Wells Shaikan-1B, Shaikan-2, Shaikan-3, Shaikan-4, Shaikan-5B, Shaikan-6 and Shaikan-8. Some of the tests showed extremely high potential flow rates, which is attributed to the well having penetrated natural fractures. Other tests were unsuccessful, with low or no flow, due to the bituminous nature of the oil in places, and possibly the paucity of connected fractures in parts. In addition, some tests failed due to operational difficulties.

The carrying out of DSTs has been operationally challenging, due to safety considerations caused by the high H_2S content of produced fluids. Operational challenges were also caused by the fractured nature of the reservoir, which made it impossible to obtain reliable reservoir information by testing with cemented and perforated liners. GKP employed a variety of testing techniques, including open hole tests and by perforating through un-cemented casing with external inflatable packers. In addition, the high density and viscosity of the oil required the use of nitrogen lift to initiate and in some instances, to maintain flow of reservoir fluids to surface. These factors combined to make the interpretation of the DSTs difficult. However, GKP has largely addressed the ambiguity in DST interpretations caused by these limitations by conducting a large number of tests, thereby improving confidence in the overall results through repetition.

Sufficient data were gathered to ascertain oil productivity from the Jurassic and Triassic, to determine pressure gradients within the reservoirs and to identify fluid contacts. While most tests in the Jurassic produced dry oil, water was produced from Well Shaikan-5B and from Well Shaikan-6 at depths above the depth to which oil had been identified in the matrix, leading to a fairly complex model to explain the relationship between oil in the fractures and matrix (Section 5.5.2). Several tests in the Triassic produced water and samples were collected from the Kurre Chine A and Kurre Chine C reservoir intervals. In addition to the DST tests, GKP conducted a long term interference test between Wells Shaikan-1B and Shaikan-3.

GKP recorded pressures with gauges deployed down hole during the DSTs, obtaining data that could be subjected to pressure transient analysis to obtain reservoir information. Some of these data were interpretable, while other datasets were not, often due to non-stabilised flow rates caused by operational challenges. GKP's interpretation of test data indicated variable flow capacity with the permeability-thickness product over different zones ranging from 12 to nearly 10,000 Darcy.ft. The latter value is high and corresponds to a well productivity index greater than 100 stb/d/psi, suggesting significant flow contribution from the fracture network.

Wells Shaikan-1B and Shaikan-3, located 500 m apart, were put on long term production test on 20 September 2010 (Figure 5.8). Both wells produced from the Upper Jurassic reservoirs. Production was intermittent, with periods of flow interspersed with long periods of shut-in. This allowed the pressure readings in both wells to be analysed for interference effects. GKP's interpretation of the data showed very good communication between the wells in the Upper Jurassic.

From the down hole pressure gauges deployed during the DSTs, a total of 33 estimates of reservoir pressure were made. Pressure as a function of depth is illustrated in Figure 5.6. The pressure data were also transformed to excess pressure, illustrated in Figure 5.7. Excess pressure is the amount by which the absolute pressure at a point deviates from the regional water pressure. Plots of excess pressure vs. depth sharpen the definition of fluid contacts. Due to the interpretive nature of the pressure build-up data and the need to extrapolate from gauge depth to reservoir depth, pressure plots based on DST pressures are subject to greater uncertainty than pressure plots based on MDT or RFT datasets for the purposes of defining fluid contacts.

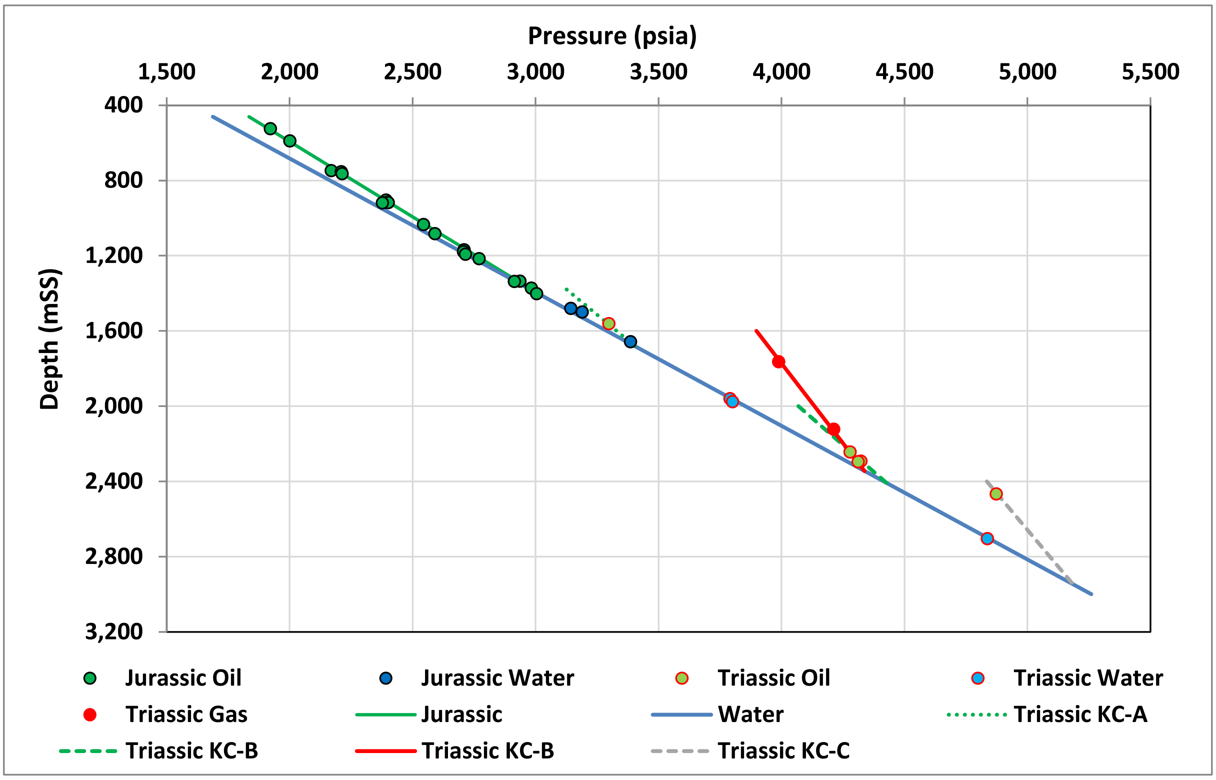

Figure 5.6: Shaikan Pressure vs Depth

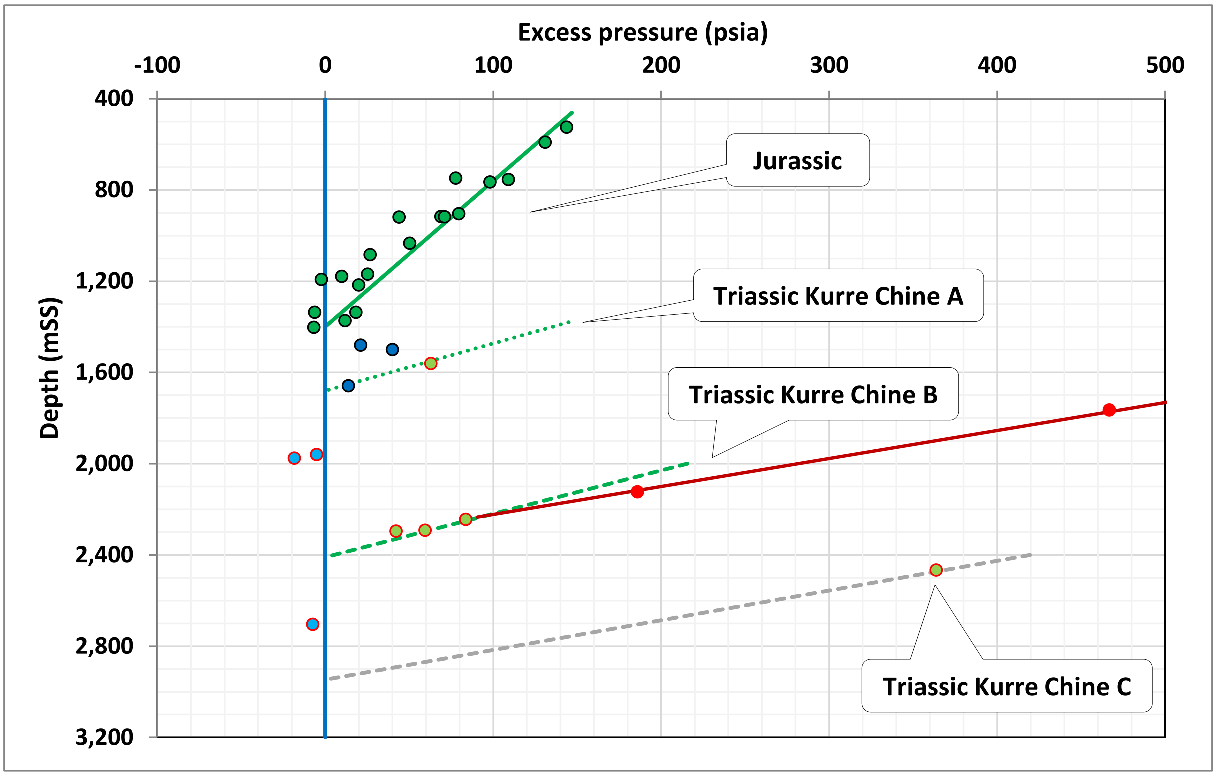

Figure 5.7: Shaikan Excess Pressure vs Depth

5.10.2. Historical Production from the Jurassic Reservoirs

The Jurassic reservoirs have been on stream almost continuously since December 2013 (Figure 5.8), apart from a period between mid-February 2015 and mid-March 2015 and a period between the latter part of February and mid-March 2016 when the field was shut in due to disruption of the pipeline export route through Turkey. Production was initially from two wells flowing at a combined rate of approximately 10 Mstb/d. This was progressively ramped up with more wells coming on stream. The current peak deliverability of the wells is close to the handling capacity of the production facilities of 45 Mstb/d. The field produced at an average oil rate of approximately 33 Mstb/d from up to nine wells during the period from 1 January 2016 to 30 June 2016. The average rate was adversely affected by the shut down early in the year. During the past three months production has remained steady at approximately 39 Mstb/d. Cumulative oil production to 30 June 2016 was 25.1 MMstb.

Production has been primarily from the upper Jurassic with eight wells producing from these intervals and one well (Well Shaikan-7E) producing from the lower Jurassic. Historical production on a well-by-well basis is shown in Figure 5.8. As at the date of this report there has been no evidence of excess gas production. There have been minor water production levels recorded in Well Shaikan-2, which has necessitated the well being choked back in the past six months. Small quantities of water have also been detected in Well Shaikan-8, which has accordingly been shut in due to the low tolerance for water in the production facilities. GKP believes the water produced to date is drilling fluid lost to the reservoir during drilling and completion operations. GKP plans to address this within the next year with the installation of desalters to allow some water production.

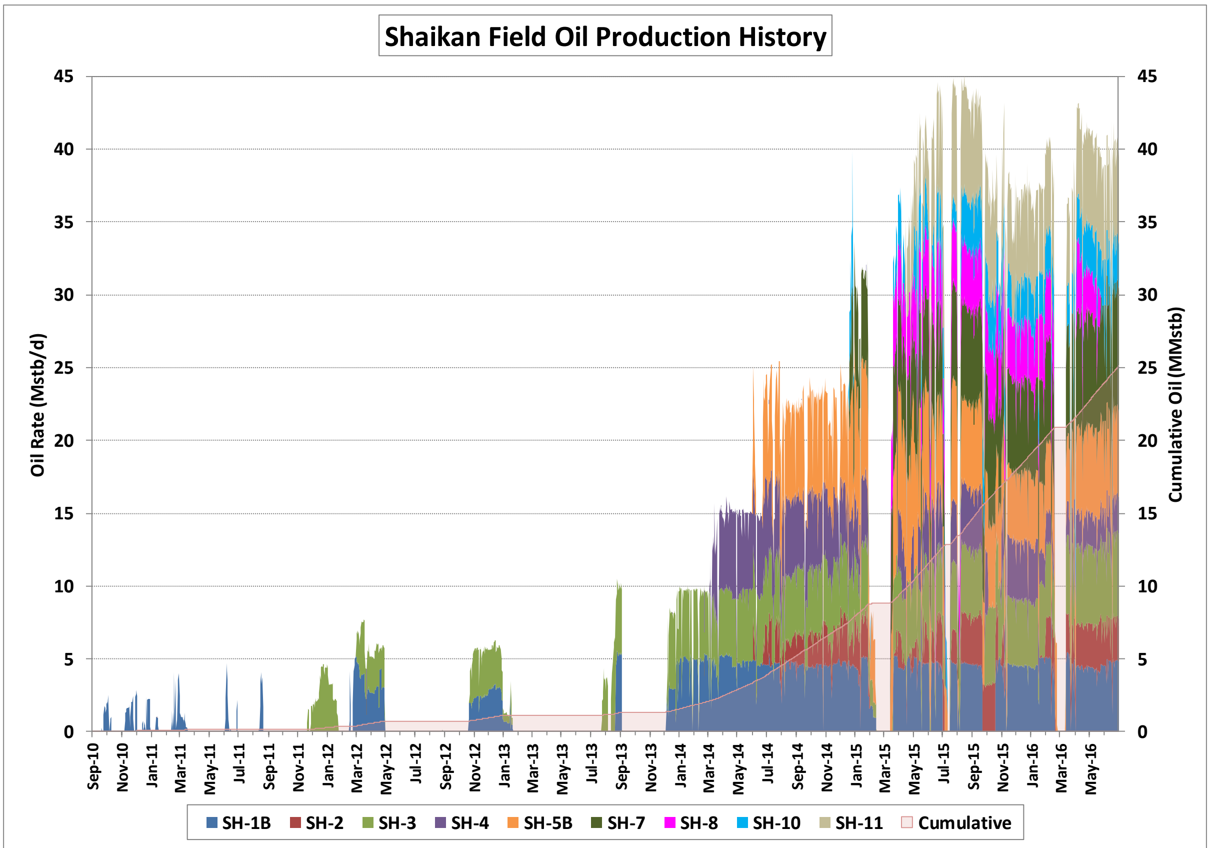

Figure 5.8 Shaikan Historical Production

Historical downhole pressure measurements over field life recorded in a selection of wells completed in the Jurassic are shown in Figure 5.9. These include the Lower Jurassic producer Shaikan-7E and the observation Well Sheikh Adi-3 to the west of the field. Pressures are observed to decline over time as fluids are extracted from the reservoirs. This occurs in producing wells as well as those wells that are not producing (observation wells), and the pressures respond rapidly in the observation wells to the opening and closing of producing wells, suggesting generally good communication within the Upper Jurassic reservoir, although the pressure decline in the eastern part of the field (Well Shaikan-2 and Well Shaikan-11) slightly lags behind the pressure decline in the central wells (Well Shaikan-3 and Well Shaikan-8).

Well SA-3C is effectively an observation well in the saddle between Shaikan and the neighbouring Sheikh Adi field, and shows a pressure response that suggests it is in pressure communication with the Shaikan field.

Pressure data recovered from downhole gauges in Wells Shaikan-8 (not shown) and Shaikan-7E show the decline in the Lower Jurassic Butmah reservoir before Well Shaikan-7E has begun producing and this has been attributed by GKP to production from the Butmah via leaking to the Shaikan-1B perforations in the Upper Jurassic. This potential leaking introduces uncertainty in the actual volumes recovered from the Upper and Lower Jurassic and complicates material balance estimates of STOIIP.

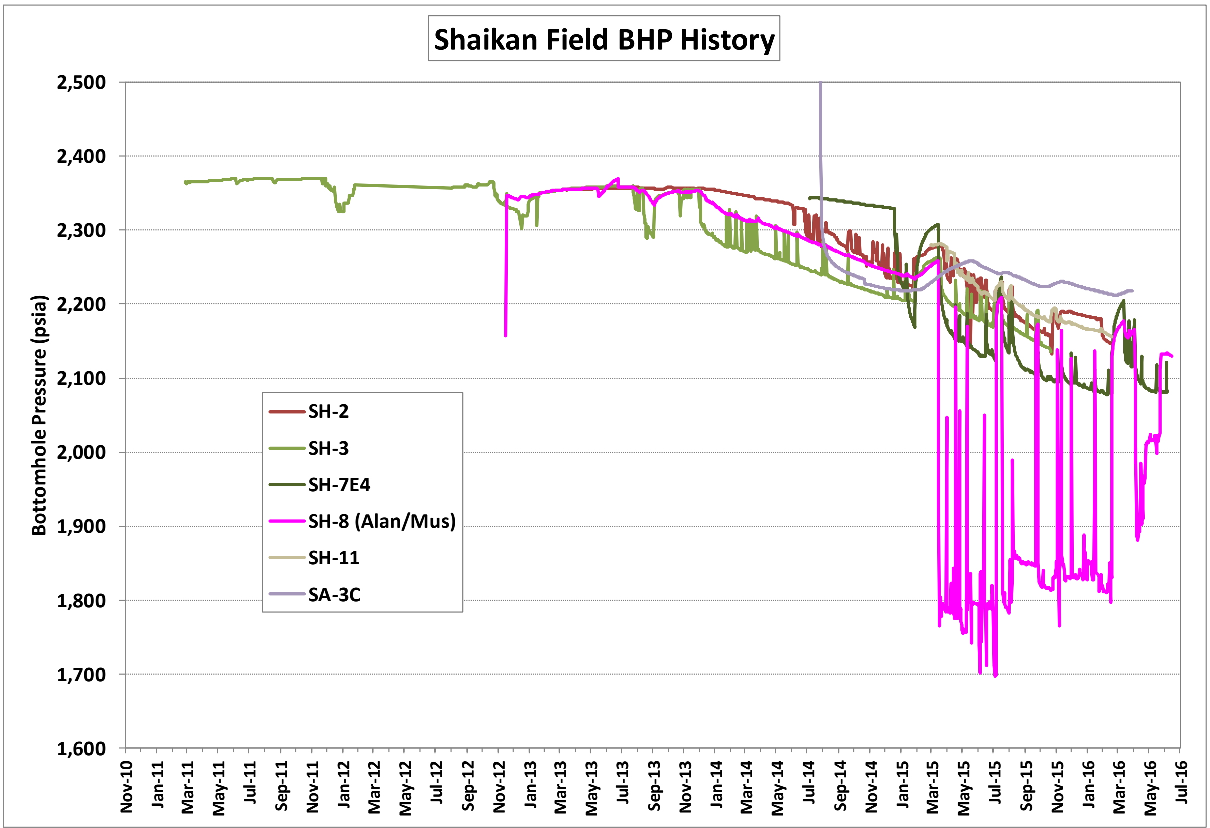

Figure 5.9: Downhole Pressure over Time in Selected Shaikan Jurassic Wells

The decline in pressure observed as a result of production suggests that the natural aquifer is not responding rapidly, if at all. This has positive implications for recovery of oil, as an expanding gas cap is likely to result in higher recovery from matrix blocks than aquifer influx.

All the wells apart from Wells Shaikan-4 and Shaikan-8 show only small amounts of pressure drawdown while producing, bearing testimony to high productivity indices and high flow potential from the open fractures.

5.10.3. Recovery Mechanisms for the Jurassic Reservoirs

ERCE has used dynamic data provided by GKP to guide estimates of recovery factors for the Shaikan Upper Jurassic reservoirs. Contrary to initial ideas that water influx from a natural aquifer would dominate the recovery process, it now appears more likely from dynamic data acquired thus far that aquifer influx is limited and that the recovery from the field will be dominated by processes associated with pressure depletion. The primary recovery mechanisms by pressure depletion are described below.

The saturation pressure of the oil in the vicinity of the crest of the structure is at, or close to, the oil's reservoir pressure. It is possible that a small primary gas cap exists, although due to uncertainty in laboratory derived data, its existence is not equivocal. Nonetheless, extraction of fluids from the reservoir will continue to cause the reservoir pressure to decline below the saturation pressure of the oil, starting at the crest and progressing through the column. This will result in gas being liberated in the reservoir and migrating upwards through the fracture network to the crest, where the primary gas cap, if it exists, will expand. If a primary gas cap does not exist, then a secondary gas cap will probably already have formed by now and it will increase in size as gas accumulates at the crest during ongoing pressure depletion. Due to the good communication within the fracture system and the considerable vertical extent of the oil column, in the order of 1,000 m, it is likely that a stable vertical displacement process within the fracture network will be achieved. Wells located high in the structure, such as Wells Shaikan-1B and -3, will gas out before those located deeper in the column. This is expected to occur in the next couple of years. A very high recovery factor would be achieved from the fractures by this mechanism if well offtake points are appropriately located deep in the column and if the well offtake rates and well spacing are such that gravity stable displacement is achieved.

As pressure declines in the fracture network, a pressure differential will be established between the matrix blocks and the surrounding fractures, causing movement of oil out of the blocks into the fractures that provide the conduits to the wells. This movement will be driven by expansion of the oil within the matrix blocks due to the compressibility of the oil. This expulsion will continue until the oil in the matrix blocks reaches its saturation pressure and free gas is liberated in the pore space of the matrix blocks. Recovery from the matrix via this mechanism is determined by the compressibility of the oil, the saturation pressure of the oil (which varies through the column) and the effectiveness of the transmittal of pressure within the matrix blocks, which in turn is affected by size and shape of the matrix blocks and the permeability.

The gas liberated in the matrix blocks after the pressure drops below the saturation pressure is expected to be immobile initially and it is likely that oil will continue to be liberated from the matrix blocks until the gas saturation in the matrix blocks reaches a critical value above which it becomes mobile and, due to its low viscosity relative to oil, moves preferentially out of the matrix blocks and into the fractures. At this point recovery of oil from the matrix blocks will slow down and effectively cease under a purely depletion drive scenario. Recovery of oil by this mechanism is affected primarily by the critical gas saturation, which is expected to be in the range of 5 to 10%.

A further recovery mechanism involves gravity drainage of oil from matrix blocks surrounded by gas, which is driven by the forces of capillary pressure. Recovery by this mechanism is dependent on many factors that are currently poorly constrained in Shaikan, such as the gas-oil capillary pressure of the matrix, the gas-oil relative permeability curves and crucially, the physical dimensions of the matrix blocks and capillary continuity. GKP and ERCE have carried out fairly extensive theoretical calculations to assess the range of uncertainty in this component of recovery factor.

Our understanding of the development plan provided by GKP is that the produced gas will be processed and sweet gas will be utilised in the field and possibly exported or re-injected. Sour gas will be re-injected into the reservoir. Studies are currently being undertaken by GKP to optimise the injection strategy. GKP has informed ERCE verbally that GKP has permission from the authorities to dispose of sour gas by injection into the reservoir.

ERCE estimated low, best and high case recovery factors of 60%, 75% and 90% for the medium viscosity oil in the fractures down to 1,350 mTVDSS. These recovery factors are based on the assumption that the field will be extensively developed, with an adequate number of wells and appropriate well design. Recovery from the deeper higher viscosity oil in the fractures down to the OWC at 1,450 mTVDSS will be lower and we have used recovery factors of 10% 15% and 20% for this interval.

For the matrix, there is considerable uncertainty regarding recovery factors. We have estimated low, best and high case recovery factors of 5%, 10% and 20% for the oil in the matrix down to 1,350 mTVDSS. For the interval between 1,350 mTVDSS and 1,450 mTVDSS, we have estimated low, best and high case recovery factors of 0%, 2% and 5% from the matrix. For the interval 1,450 mTVDSS to the OWC in the matrix, 1,950 mTVDSS, we have previously used low, best and high recovery factors of 0%, 2% and 5%. This interval contains large volumes of oil in the matrix, but is water bearing in the fractures and to date no viable development plan has been identified to recover these volumes. Nonetheless, based on the assumption that a viable recovery mechanism will be identified, which may require gas injection, depletion or the implementation of an improved recovery technique, we have retained our estimates of recovery factors of 0%, 2% and 5%.

5.10.4. Recovery Mechanisms for the Cretaceous Reservoirs

The highly viscous oil at shallow depth is currently considered unrecoverable, both in the fractures and in the matrix. At the time of preparing this report, no realistic method for recovering this oil was evident although further studies into the use of thermal methods might be usefully undertaken.

The lower viscosity oil at greater depth is likely to be recoverable and we assigned recovery factors of 20%, 30% and 40% for the low, best and high case estimates for the fracture network. These recovery factors are based on the assumption of an effective water drive through the fractures, either in the form of influx from a natural aquifer or from water injection. Achieving these recovery factors also relies on an adequate number of wells and appropriate well design, which have yet to be defined. GKP has included a nominal development of the Cretaceous in the Field Development Plan Addendum, which was approved by the Kurdistan authorities. However, the development concept is still immature and consequently, ERCE has classified the estimates of recoverable volumes for the Cretaceous as Contingent Resources, contingent on further clarification of the development plan.

Despite this oil being lower viscosity than the overlying oil, it is still highly viscous and therefore we do not consider the oil in the matrix to be recoverable. Within the Cretaceous interval of the Shaikan field, therefore, we have reported Contingent Resources for oil from the fractures only and, within the fracture network, only for oil occurring below the depth at which the transition from a highly viscous state to a state of lower viscosity occurs.

5.10.5. Recovery Mechanisms for the Triassic Reservoirs

The Triassic reservoirs are different from the Jurassic in pressure, fluid properties and hydrocarbon column height. In the Triassic, the pressure is higher, the fluid is light oil with high GOR and rich gas condensate and the hydrocarbon columns are significantly shorter than in the Jurassic. The light nature of the oil, low viscosity and high pressure favour good recovery. Development of the Triassic has not been finalised and estimates of recoverable volumes from all reservoirs in the Triassic have been classified as Contingent Resources.

Triassic Kurre Chine A (KCA): The KCA reservoir has been interpreted to contain oil with no primary gas cap. Estimates of recovery factors have been based on the premise that a similar recovery mechanism will apply as for the Jurassic reservoirs. ERCE has used a range of 60%, 70% and 80% for the low, best and high cases for recovery factors from the fractures. The corresponding values for the matrix are 5%, 10% and 20%.

Triassic Kurre Chine B (KCB): The KCB reservoir has been interpreted to contain oil with a primary gas cap. ERCE has assumed that depletion drive with gas cap expansion would be the primary drive mechanism. We applied an uncertainty range of 60%, 70% and 80% for low, best and high cases to the free gas, the condensate and the oil in the fractures. Lower recovery factors are expected from the matrix. For oil in the matrix, we have used an uncertainty range of 5%, 10% and 20%. We have also applied this recovery factor range of 5%, 10% and 20% for solution gas in the matrix. For free gas in the matrix, we assumed an uncertainty range of 50%, 60% and 70%, while for the condensate in the matrix, we assumed a range of 20%, 30% and 40%.

Triassic Kurre Chine C (KCC): The KCC reservoir has been interpreted to contain oil with no primary gas cap. No development plan has been defined and no detailed analysis of recovery factors has been completed. For the fracture network the range of recovery factors used by ERCE is 60%, 70% and 80% for the low, best and high cases for oil and solution gas. The corresponding range for the matrix is 5%, 10% and 20% for oil and solution gas.

5.11. Shaikan Phase 1-2 Development Plan

GKP has described the large scale development of Shaikan in the FDP (January 2013) and Addendum 01 (June 2013) submitted to the Kurdistan Authorities. GKP informed ERCE that it has received approval for its plans to proceed with the development. The FDP and Addendum focus on development of the Jurassic interval, but also include limited development of the Cretaceous and Triassic intervals, the objective being to gauge reservoir response before further development of these intervals is planned. The development described in the FDP comprises several progressive phases, defined by increasing facility capacities and well count and referred to as phases 0, 1, 2 and 3.

In the Listing CPR ERCE attributed Reserves for the development of the Shaikan Jurassic reservoirs comprising 26 wells. GKP has subsequently acquired data that suggest that the main drive mechanism is likely to be through pressure depletion and gas cap expansion. With the benefit of reservoir performance and greater confidence in the drive mechanism, GKP has been able to refine plans for the next part of the development.

In addition to the nine existing production wells, GKP's current plan comprises 32 production wells in the Jurassic reservoirs, one production well in the Cretaceous and five production wells in the Triassic reservoirs. Two further wells for gas injection and one water disposal well are planned in addition to a Permian exploration well. The development plan includes facilities upgrades to a maximum oil production capacity of 115 Mstb/d and the construction of a spur pipeline from the field to the main trunk export pipeline. We refer to this development in this CPR as 'Shaikan Phase 1-2', as it includes all of Phase 1 as described in the Field Development Plan and a substantial portion of Phase 2. The Reserves reported in this CPR are therefore based on the implementation of the Shaikan Phase 1-2 development.

This revised 'Shaikan Phase 1-2' plan was submitted to the Kurdistan authorities in a Field Development Plan Update ("FDP Update") report in December 2015. It was anticipated that approval of this plan would occur in 2016, with first oil through the new facilities occurring in early 2019.

In the light of the current low oil price environment, in early 2016 GKP and its partners deferred a Final Investment Decision for the FDP Update until end-2017, which will result in a one year delay in first oil through the new production facilities. Expenditure on the new plant is now planned to start until 2018 with first oil through the new facilities in 2020.

An interim plan, termed the "Bridge to the FDP" has been formulated, which details interim activities and expenditure to mitigate the expected decline in oil rate from the existing well stock and maintain current production levels through the existing plant until FID. This plan envisages some debottlenecking work to be carried out at the end of 2016 that will lower the inlet pressure to the separators, the installation of desalters to treat produced emulsions believed by Gulf Keystone to be formed by the mixing of oil with drilling fluid lost to the reservoir during drilling and completion, the drilling of a single well in the second half of 2017 and the installation of four electrical submersible pumps (ESPs) from April 2017 to boost the production rates. We have assumed this interim plan is implemented in the CPR. It is possible a second well may need to be drilled in the event that one or both of the two crestal Wells Shaikan-1 and -3 gas out earlier than expected.

In this CPR, as in the September 2015 CPR, ERCE has attributed Reserves based on GKPs current plans, which will bring the total development well count to 51 as set out in Table 5.9 for the low and best case scenarios. GKP plans to install further facilities in the form of a CPF with three trains, which will bring the total oil processing capacity up to 115 Mstb/d. Thus the development for which Reserves are attributed in this CPR incorporates Phase 1 and a substantial part of Phase 2 as set out in the 2013 FDP. For the purposes of this CPR, we therefore refer to this development as the 'Shaikan Phase 1-2' development. Note that for the high case, we have included 11 additional wells to drain the Jurassic reservoirs (Table 5.9).

The Shaikan Phase 1-2 development plan is focussed on the Jurassic reservoirs with a further 32 production wells planned to be drilled and completed at different levels in the Jurassic reservoirs. Some of these wells might be drilled with horizontal drainholes or as highly deviated wells. Furthermore, the plan calls for the initial development of the Triassic reservoirs with five production wells and the Cretaceous reservoirs with 1 production well.

Table 5.9: Well count for the Shaikan Phase 1-2 Development and Basis for Reserves Estimation

Well type	Number of Wells	
	Low and Best Cases	High Case
Existing Jurassic producing wells	9	9
Future Jurassic production wells	32	43
Future Triassic production wells	5	5
Future Cretaceous production wells	1	1
Total production wells	**47**	**58**
Future gas disposal wells	2	2
Future water disposal wells	1	1
Total development wells	**50**	**61**
Permian exploration well/ development well	1	1
Total well count	**51**	**62**

5.11.1. Shaikan Phase 1-2 Production Forecasts

GKP has presented three sets of production forecasts, with associated capex and opex for low, best and high cases for the Phase 1 development of the Jurassic, Triassic and Cretaceous reservoirs. ERCE has modified its production forecasts presented in the September 2015 CPR to reflect the updated development plans and phasing set out in the FDP Update and the Bridge to the FDP, including the recently announced one year delay to the FDP Update timetable to reflect the deferral of FID to the end of 2017. The forecasts are presented graphically in Figure 5.10 and listed in Table 5.10 (low case), Table 5.11 (best case) and Table 5.12 (high case).

It has been assumed that export would continue by trucking to Fishkabour and then pipeline to Ceyhan until 2020, with a facility capacity of 45 Mstb/d. It has been assumed that a new Central Processing Facility (CPF) with three production trains, would be constructed and become fully operational in stages, with full production capacity reached in the first half of 2021. It has further been assumed that export via pipeline would become fully operational in 2020 giving a total production capacity of 115 Mstb/d.

In order to sustain the plateau into the future, GKP plans to commence further drilling of Jurassic wells in 2018 and has shown a nominal drilling schedule continuing through 2034, with a total of 32 further Jurassic wells over and above those already on production. How many of these wells will actually be needed, the subsurface locations of the wells and the types of wells have not been finalised and will be determined as the development unfolds. Nonetheless, ERCE believes that the overall well counts shown in Table 5.9 are adequate to recover the forecast volumes presented in Table 5.10 to Table 5.12 and Figure 5.10. Note that for the high case, we have included 11 additional wells to drain the Jurassic reservoirs

Five Triassic wells are scheduled to be drilled commencing in 2019 with first oil in 2021. A single well is planned to be drilled in the Cretaceous in 2019, to come on stream in 2020. Dynamic information from the Triassic and Cretaceous reservoirs will be used to further plan the development of thee reservoirs.

The forecasts show average oil production rates that take downtime into account. The profiles shown here are forecasts to 30 June 2043 when the licence expires and are estimates of technically recoverable volumes. These profiles have been used as input into an economic model, which has been used to estimate the economic cut-off dates for each of the cases to assign Reserves.

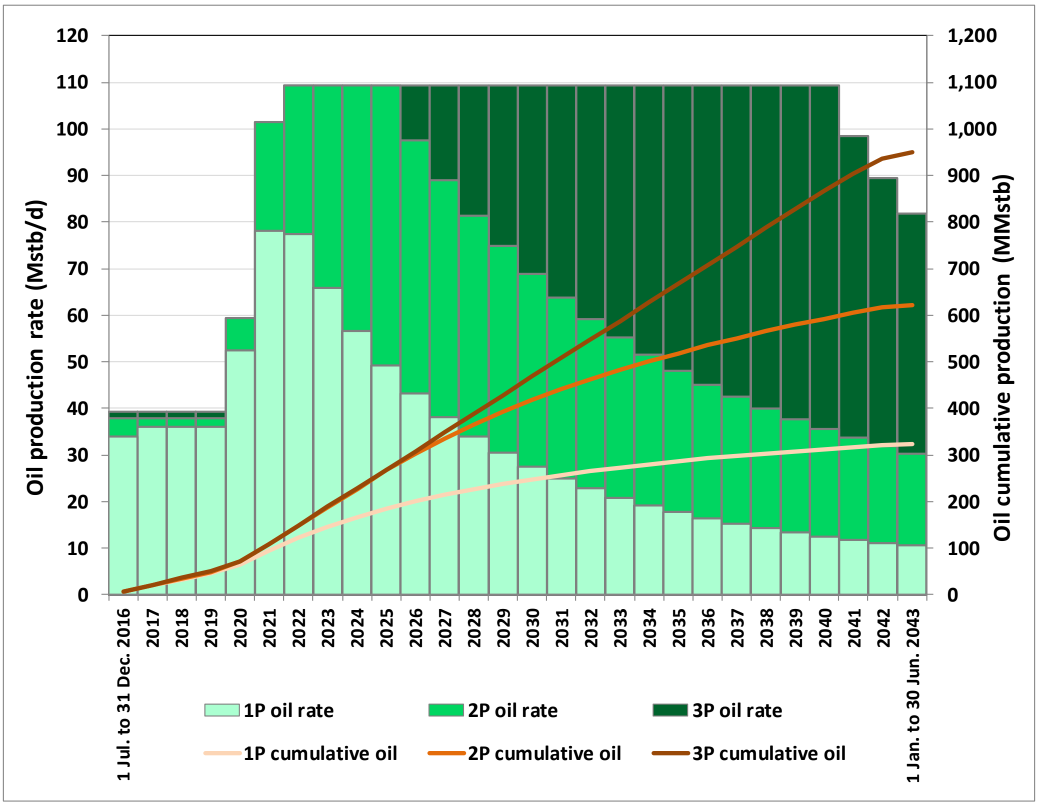

Figure 5.10: Production Forecasts for Shaikan Phase 1-2 Development

Table 5.10: Shaikan Phase 1-2 Development Low Case Production Forecasts

Year	1P							
	Shaikan Jurassic		Shaikan Triassic		Shaikan Cretaceous		Shaikan Total	
	Qo (Mstb/d)	Op (MMstb)	Qo (Mstb/d)	Op (MMstb)	Qo (Mstb/d)	Op (MMstb)	Qo (Mstb/d)	Op (MMstb)
1 Jul. to 31 Dec. 2016	34.0	6.3	0.0	0.0	0.0	0.0	**34.0**	**6.3**
2017	36.0	19.4	0.0	0.0	0.0	0.0	**36.0**	**19.4**
2018	36.0	32.5	0.0	0.0	0.0	0.0	**36.0**	**32.5**
2019	36.0	45.7	0.0	0.0	0.0	0.0	**36.0**	**45.7**
2020	52.5	64.9	0.0	0.0	0.0	0.0	**52.5**	**64.9**
2021	77.4	93.1	0.0	0.0	0.7	0.3	**78.1**	**93.4**
2022	66.8	117.5	10.0	3.7	0.6	0.5	**77.4**	**121.7**
2023	57.1	138.4	8.3	6.7	0.5	0.7	**65.9**	**145.7**
2024	49.3	156.4	6.9	9.2	0.4	0.8	**56.7**	**166.5**
2025	43.0	172.1	5.9	11.4	0.4	1.0	**49.3**	**184.5**
2026	37.8	185.9	5.1	13.2	0.3	1.1	**43.2**	**200.2**
2027	33.5	198.1	4.4	14.9	0.3	1.2	**38.2**	**214.2**
2028	29.9	209.1	3.9	16.3	0.3	1.3	**34.0**	**226.6**
2029	26.8	218.9	3.5	17.5	0.2	1.4	**30.5**	**237.8**
2030	24.2	227.7	3.1	18.7	0.2	1.4	**27.5**	**247.8**
2031	22.0	235.7	2.8	19.7	0.2	1.5	**25.0**	**256.9**
2032	20.1	243.1	2.5	20.6	0.2	1.6	**22.8**	**265.3**
2033	18.4	249.8	2.3	21.4	0.2	1.6	**20.8**	**272.9**
2034	17.0	256.0	2.1	22.2	0.1	1.7	**19.2**	**279.9**
2035	15.7	261.7	1.9	22.9	0.1	1.7	**17.7**	**286.3**
2036	14.6	267.1	1.7	23.5	0.1	1.8	**16.4**	**292.3**
2037	13.6	272.0	1.6	24.1	0.1	1.8	**15.3**	**297.9**
2038	12.7	276.7	1.5	24.6	0.1	1.8	**14.3**	**303.1**
2039	11.9	281.0	1.4	25.1	0.1	1.9	**13.4**	**308.0**
2040	11.2	285.1	1.3	25.6	0.1	1.9	**12.6**	**312.6**
2041	10.6	289.0	1.2	26.0	0.1	1.9	**11.8**	**316.9**
2042	10.0	292.6	1.1	26.4	0.1	2.0	**11.2**	**321.0**
1 Jan. to 30 Jun. 2043	9.5	294.3	1.0	26.6	0.1	2.0	**10.6**	**322.9**

Table 5.11: Shaikan Phase 1-2 Development Best Case Production Forecasts

Year	2P							
	Shaikan Jurassic		Shaikan Triassic		Shaikan Cretaceous		Shaikan Total	
	Qo (Mstb/d)	Op (MMstb)	Qo (Mstb/d)	Op (MMstb)	Qo (Mstb/d)	Op (MMstb)	Qo (Mstb/d)	Op (MMstb)
1 Jul. to 31 Dec. 2016	38.0	7.0	0.0	0.0	0.0	0.0	**38.0**	**7.0**
2017	38.0	20.9	0.0	0.0	0.0	0.0	**38.0**	**20.9**
2018	38.0	34.7	0.0	0.0	0.0	0.0	**38.0**	**34.7**
2019	38.0	48.6	0.0	0.0	0.0	0.0	**38.0**	**48.6**
2020	59.4	70.3	0.0	0.0	0.0	0.0	**59.4**	**70.3**
2021	100.4	107.0	0.0	0.0	1.0	0.4	**101.4**	**107.4**
2022	98.4	142.9	10.0	3.7	0.9	0.7	**109.3**	**147.2**
2023	98.5	178.9	10.0	7.3	0.8	1.0	**109.3**	**187.1**
2024	98.6	214.9	10.0	11.0	0.7	1.2	**109.3**	**227.1**
2025	98.7	250.9	10.0	14.6	0.6	1.4	**109.3**	**267.0**
2026	87.0	282.7	10.0	18.3	0.5	1.6	**97.6**	**302.6**
2027	79.8	311.8	8.7	21.4	0.5	1.8	**88.9**	**335.0**
2028	73.4	338.7	7.6	24.2	0.4	1.9	**81.4**	**364.8**
2029	67.7	363.4	6.7	26.6	0.4	2.1	**74.8**	**392.1**
2030	62.7	386.3	5.9	28.8	0.4	2.2	**69.0**	**417.3**
2031	58.2	407.6	5.3	30.7	0.3	2.3	**63.8**	**440.6**
2032	54.2	427.4	4.8	32.4	0.3	2.4	**59.3**	**462.3**
2033	50.6	445.9	4.3	34.0	0.3	2.5	**55.2**	**482.4**
2034	47.3	463.1	3.9	35.4	0.3	2.6	**51.5**	**501.2**
2035	44.4	479.3	3.6	36.7	0.2	2.7	**48.2**	**518.8**
2036	41.7	494.6	3.3	37.9	0.2	2.8	**45.2**	**535.3**
2037	39.2	508.9	3.0	39.0	0.2	2.9	**42.4**	**550.8**
2038	37.0	522.4	2.8	40.0	0.2	3.0	**39.9**	**565.4**
2039	34.9	535.1	2.6	41.0	0.2	3.0	**37.7**	**579.1**
2040	33.0	547.2	2.4	41.9	0.2	3.1	**35.6**	**592.2**
2041	31.3	558.6	2.2	42.7	0.2	3.1	**33.7**	**604.4**
2042	29.7	569.5	2.1	43.4	0.2	3.2	**31.9**	**616.1**
1 Jan. to 30 Jun. 2043	28.2	574.6	1.9	43.8	0.1	3.2	**30.3**	**621.6**

Table 5.12: Shaikan Phase 1-2 Development High Case Production Forecasts

Year	3P							
	Shaikan Jurassic		Shaikan Triassic		Shaikan Cretaceous		Shaikan Total	
	Qo (Mstb/d)	Op (MMstb)	Qo (Mstb/d)	Op (MMstb)	Qo (Mstb/d)	Op (MMstb)	Qo (Mstb/d)	Op (MMstb)
1 Jul. to 31 Dec. 2016	39.2	7.2	0.0	0.0	0.0	0.0	**39.2**	**7.2**
2017	39.2	21.5	0.0	0.0	0.0	0.0	**39.2**	**21.5**
2018	39.2	35.8	0.0	0.0	0.0	0.0	**39.2**	**35.8**
2019	39.2	50.1	0.0	0.0	0.0	0.0	**39.2**	**50.1**
2020	59.4	71.9	0.0	0.0	0.0	0.0	**59.4**	**71.9**
2021	90.4	104.9	10.0	3.7	1.0	0.4	**101.4**	**108.9**
2022	98.3	140.8	10.0	7.3	0.9	0.7	**109.3**	**148.8**
2023	98.4	176.7	10.0	11.0	0.8	1.0	**109.3**	**188.6**
2024	98.5	212.8	10.0	14.6	0.7	1.3	**109.3**	**228.6**
2025	98.6	248.7	10.0	18.3	0.7	1.5	**109.3**	**268.5**
2026	98.6	284.7	10.0	21.9	0.6	1.7	**109.3**	**308.4**
2027	98.7	320.7	10.0	25.6	0.6	2.0	**109.3**	**348.3**
2028	98.7	356.9	10.0	29.2	0.5	2.2	**109.3**	**388.2**
2029	98.8	392.9	10.0	32.9	0.5	2.3	**109.3**	**428.1**
2030	98.8	429.0	10.0	36.5	0.5	2.5	**109.3**	**468.0**
2031	99.8	465.4	9.0	39.8	0.4	2.7	**109.3**	**507.9**
2032	100.6	502.2	8.2	42.8	0.4	2.8	**109.3**	**547.9**
2033	101.4	539.2	7.5	45.6	0.4	3.0	**109.3**	**587.7**
2034	102.0	576.4	6.9	48.1	0.4	3.1	**109.3**	**627.6**
2035	102.6	613.9	6.3	50.4	0.3	3.2	**109.3**	**667.5**
2036	103.1	651.6	5.9	52.5	0.3	3.3	**109.3**	**707.5**
2037	103.5	689.4	5.4	54.5	0.3	3.4	**109.3**	**747.3**
2038	103.9	727.3	5.0	56.4	0.3	3.5	**109.3**	**787.2**
2039	104.3	765.4	4.7	58.1	0.3	3.6	**109.3**	**827.1**
2040	104.6	803.7	4.4	59.7	0.3	3.7	**109.3**	**867.1**
2041	94.2	838.1	4.1	61.2	0.2	3.8	**98.5**	**903.1**
2042	85.5	869.3	3.8	62.6	0.2	3.9	**89.5**	**935.7**
1 Jan. to 30 Jun. 2043	77.9	883.4	3.6	63.2	0.2	3.9	**81.7**	**950.5**

5.11.2. Wells and Surface Facilities Costs

The technical definition, specification and cost of wells, process and export facilities, as documented in various GKP documents and data sets, including the budget forecasts, have been reviewed by ERCE and found to be reasonable. In the preparation of this CPR, ERCE has made use of:

- Cost data that GKP has provided for the purposes of this review, including information provided in the FDP Update, Bridge to FDP and FEED documents.
- Costs and cost metrics prepared by ERCE during previous phases of work on this particular asset.
- Costs available to ERCE team members from analogue projects.

Lifetime Development and Operational Costs. Table 5.13 shows the various underlying 'cost components' (wells, facilities, opex). The data in Table 5.13 relate to the "best estimate case", but are also relevant to the low and high cases, other than in the high case where the well count is greater. "Phase X" in the table relates to the additional capex required to maintain production at approximately 38 Mstb/d until the start of Phase 1-2. (Note that in Table 5.13, ESPs are included as capex items for Phase X, while they are included as opex items for Phase 1-2.)

Table 5.13: Development Cost Components (Best Case Estimate)

Development Cost Components	Unit Cost (US$ MM)	Total (US$ MM)
Phase X Capex		
Jurassic well, Phase X, 2017*	19.0	19.0
Capex, Phase X		24.0
New ESPs installed in existing wells, Phase X	6.5	26.0
Total Phase X Capex		**69.0**
Phase 1-2		
Well, Jurassic, Cretaceous & Disposal	23.0	805.0
Well, Triassic	41.0	205.0
Well, Permian	45.0	45.0
Owners Pre-Dev, Phase 1-2	15.0	15.0
Infrastructure, Phase 1-2		28.6
Flowline, Phase 1-2	4.0	160.0
CPF Train 1	358.2	358.2
CPF Train 2	268.2	268.2
CPF Train 3	268.2	268.2
Export pipeline, Phase 1-2		63.0
Total Phase 1-2		**2,216.2**
Opex (all phases, not factored for part years)		
Opex, Variable, $ per bbl	0.33	200.3
Opex, Fixed, per yr (for 2017, before 2X factor for Phase 1-2)	45.7	2,271.1
Opex, Fixed, per yr (for 2022+)	91.4	
Opex, G&A, per yr	22.5	606.5
ESP Replacement, Phase 1-2	6.5	1,106.9
Total Opex		**4,184.7**

Well Costs. The costs of the various well types estimated by GKP and used in GKP's project forecasts are presented in Table 5.13. Costs were provided by GKP for development wells that target various formations (Jurassic, etc.). These well costs provided by GKP appear reasonable, when compared with actual costs of wells drilled to date.

Surface Facilities Costs. The components of surface facilities that contribute the most capex are the process trains, of which there are three. Cost estimates for the plant reflect the improved project definition following completion of FEED studies in early 2016.

Table 5.14 presents forecasts of capital and operating costs (in 2016 US$) for each of the low, best and high forecasts.

Table 5.14: Capex and Opex Forecasts for Shaikan Phase 1-2 Development.

Year	Low Case		Best Case		High Case	
	Capex (US$ MM)	Opex (US$ MM)	Capex (US$ MM)	Opex (US$ MM)	Capex (US$ MM)	Opex (US$ MM)
1 Jul. to 31 Dec 2016	11.5	30.6	11.5	30.6	11.5	30.6
2017	54.2	72.5	54.2	72.7	54.2	72.9
2018	398.1	72.5	398.1	72.7	371.1	72.9
2019	543.9	94.8	543.9	95.0	543.9	93.3
2020	453.0	127.0	453.0	127.8	426.0	126.0
2021	176.7	150.8	176.7	153.5	176.7	149.8
2022	0.0	167.7	0.0	171.5	0.0	167.8
2023	54.0	166.3	54.0	171.5	54.0	167.8
2024	54.0	168.9	54.0	175.2	54.0	171.5
2025	27.0	171.8	27.0	178.9	54.0	175.2
2026	99.0	172.9	99.0	179.4	99.0	178.9
2027	54.0	177.9	54.0	183.9	54.0	184.5
2028	99.0	181.1	99.0	186.7	99.0	188.2
2029	27.0	186.2	27.0	191.5	108.0	193.8
2030	99.0	187.7	99.0	192.7	153.0	201.2
2031	54.0	185.6	54.0	190.2	108.0	203.0
2032	27.0	183.5	27.0	187.8	81.0	204.9
2033	54.0	177.7	54.0	181.8	81.0	203.0
2034	0.0	175.6	0.0	179.5	27.0	203.0
2035	0.0	168.0	0.0	171.6	27.0	197.5
2036	0.0	162.3	0.0	165.7	0.0	193.8
2037	0.0	154.7	0.0	157.9	0.0	186.3
2038	0.0	149.0	0.0	152.1	0.0	180.8
2039	0.0	143.3	0.0	146.2	0.0	175.2
2040	0.0	137.7	0.0	140.4	0.0	169.6
2041	0.0	132.0	0.0	134.6	0.0	162.8
2042	0.0	126.4	0.0	128.8	0.0	156.1
1 Jan. to 30 Jun. 2043	0.0	63.2	0.0	64.3	0.0	77.6
Total	**2,285.2**	**4,087.6**	**2,285.2**	**4,184.7**	**2,582.2**	**4,487.7**

5.12. Shaikan Economic Evaluation

ERCE has carried out economic evaluations of the Shaikan Phase 1-2 development based on production forecasts presented in Table 5.10 to Table 5.12 and on costs presented in Table 5.14.

The industry standard discounted cash flow method using a point-forward analysis of nominal net cash flows from 1 July 2016 was used in this evaluation. Projected estimates of production, price and costs through the remaining life of the field were audited. These were used to estimate net cash flows, subject to the terms of the Shaikan PSC. The net cash flows were then discounted to determine the industry standard economic metrics to determine viability and profitability of the assets.

The sections below describe the main terms of the Shaikan PSC and other related commercial terms from an economic perspective, and itemise assumptions that have been made when incorporating them into the cash flow model.

The PSC (2007) as amended by the First Amendment (2010) allows for the KRG to back in up to 20% and a Third Party Participation nominated by the KRG to take up to a maximum of 15%. Under this scenario, GKP's interest would be diluted to 54.4% (comprising 51.0% for GKP and 3.4% for the interest held in trust by TKI). ERCE has been informed by GKP that it has entered in to an agreement with Kurdistan Ministry of Natural Resources (MNR) dated 16 March 2016 (the March Agreement) which confirms the KRG's back in right of 20%. In addition, the new agreement assigns half of the Third Party interest (7.5%) to the non-government contractors pro rata to their existing working interests with the remaining 7.5% to be held by the MNR. Also the Capacity Building Value for GKP and TKI is reduced from 40% to 30%.

The March Agreement has still to be ratified by all parties through an amendment to the PSC. If amended, GKP's working interest under the PSC will be 58.0% (comprising 54.375% for GKP and 3.625% for TKI) with a cost exposure of 64.0% and the Capacity Building Value for GKP and TKI will be reduced from 40% to 30%.

GKP has requested that ERCE's Base Case economic evaluation is based on the terms set out in the March Agreement. ERCE has also run economic sensitivity cases under the terms of the current PSC assuming both fully diluted and undiluted interests. These were the fiscal terms assumed in the 2014 Listing CPR and also the CPR issued in September 2015.

5.12.1. Shaikan Base Case Fiscal Terms

Government Royalty. A royalty is payable to the KRG on all production from the Contract Area. This is applied at a rate of 10.00% on all export crude oil and is payable in cash or, if the KRG nominates, in kind.

Cost Recovery. The Contractor is entitled to up to 40.00% of Export Crude Oil after the deduction of Royalties for the recovery of Petroleum Costs. Unrecovered costs are carried forward for recovery in the following period but not beyond the termination of the Contract. All Available Petroleum not used for cost recovery shall be deemed Profit Petroleum. Brought forward balances relating to past costs and unrecovered costs have been provided by GKP and accounted for in the cash flow modelling.

Profit Sharing and Capacity Building Payments. Profit Petroleum (Profit Crude Oil and Profit Natural Gas) is the amount of Available Petroleum available after the deduction of Royalty and Cost Recovery. The Contractor is entitled to a share of the Profit Petroleum during production, determined by the R-Factor, as follows:

- R = X / Y, where
- X = Cumulative Revenues received by the Contractor (Cost Recovery and Profit Share),
- Y = Cumulative Petroleum Costs incurred by the Contractor, from the date of the Contract.

The Contractor Share of Profit Crude Oil is determined as follows, namely at an upper level of 30% prior to breakeven reducing linearly to 15% for R above two:

- R < 1: Profit Share = 30%
- 1 < R < 2: Profit Share = 30 – (30 - 15) * (R – 1) / (2 – 1)%
- R > 2: Profit Share = 15%

Capacity Building Payments (CBP) comprise 30% of the respective parties' share of Profit Petroleum, payable to the KRG and are not cost recoverable.

Taxation. Each Contractor entity is free of all tax on the income, assets and activity arising from the Contract (including Withholding Tax, Additional Profits Tax, Surface Tax and Windfall Profits Tax) and the KRG indemnifies each entity against any assessment of tax. The KRG share of Profit Petroleum is deemed to include the Corporate Income Tax (CIT) levied on and due from the Contractor entities, which is paid by the KRG on behalf of the Contractor.

GKP Participation and Paying Interest. GKP's working interest is 58.0% (comprising 54.375% for GKP and 3.625% for TKI) with a cost exposure of 64.0%.

Net Entitlement. GKP "Net Entitlement Reserves" are the sum of GKP's share of cost recovery oil plus GKP's portion of the Contractor's share of profit oil under the PSC terms in Kurdistan. GKP's profit oil is net of royalty and is calculated before deductions for Capacity Building Payments. The evaluation of Net Entitlement Barrels includes an additional entitlement from "Tax Barrels" arising from the deemed Corporate Income Tax under the PSC paid on GKPI's behalf from the Government's share of Profit Petroleum.

5.12.2. General Economic Modelling Assumptions

Brent Oil Price Assumptions. ERCE has assumed a base case Brent oil price forecast and also evaluated a range of sensitivities (Table 5.15). GKP instructed ERCE to apply the following assumptions:

- Fiscal point: Shaikan production facility
- All crude oil sales deemed export sales, trucking to Fishkabour and then by pipeline to Ceyhan until 2020 when trucking will cease and all export sales will be via a new pipeline spur.
- Brent crude oil price differentials have been applied, and include all tariffs, fees and any quality banking discounts. These are netback prices and there are no additional associated costs assumed – hence no additional cost recovery for tariffs/fees.

- Transport deductions of $5.66 per stb were assumed, as advised by GKP.
- GKP has requested ERCE to use a Shaikan quality discount to Brent for pipeline exports as shown in Table 5.16.

The oil price discount to Brent arises from oil quality considerations, notably the API gravity and sulphur content of the Shaikan crude. The MNR of the KRG currently purchases Shaikan crude at a discount of $14.7 / stb. GKP has informed ERCE that a Heads of Terms Agreement has been concluded with the MNR dated 23 February 2016, which provides that the discount applicable ($14.7 / stb) is subject to revision and the retroactive application of a Quality Bank pricing formula. The exact timing of the application of this term of the Agreement is unclear but GKP continues to press the MNR on the introduction of a Quality Bank and the adjustment of the current discount applicable, potentially based on an independent third party valuation. GKP has accordingly commissioned Channoil Consulting Limited (Channoil) to carry out a study of the Shaikan crude, and to produce forecasts of the discount to gain a better understanding of netback potentials from Shaikan crude.

Channoil was provided with the Low, Best and High case production forecasts prepared by ERCE, detailing the relative contributions from the three reservoir intervals; Triassic, Jurassic and Cretaceous. Crude oils from the three reservoir intervals have different quality factors and hence the blend of these affects the overall export stream and hence the discount. To date, production has been from the Jurassic only. Channoil carried out a marketing assessment of the Shaikan crude and prepared forecasts of discount to Brent corresponding to ERCE's Low, Best and High production forecast cases.

GKP has made the assumption that the current discount of $14.7 /stb will continue for the remainder of 2016 for all three production forecast cases. GKP has further assumed that a discount of $12.9 /stb will apply to all three production forecast cases for 2017 and 2018 and that the discounts will follow the forecasts prepared by Channoil from 2019 onwards. These assumptions made by GKP regarding oil price discounts are shown in Table 5.16. GKP has requested ERCE to use these discount forecasts in our evaluation. ERCE has not independently verified the validity of these discount forecasts.

ERCE has also carried out an economic sensitivity case based on the assumption that the current discount of $14.7 /stb will continue into the future.

Table 5.15: Brent Oil Price Assumptions

Base Case ERCE Brent Assumptions ($/bbl)	2H16E	2017E	2018E	2019E	2020E	2021E	2022E	2023E+
Real (Constant $, 2016)	46	53	60	65	68	70	70	70
Nominal ($ of the day)	46	54	62	69	74	77	79	+2.0% pa

Low Case ERCE Brent Assumptions ($/bbl)	2H16E	2017E	2018E	2019E	2020E	2021E	2022E	2023E+
Real (Constant $, 2016)	38	41	42	44	45	45	45	45
Nominal ($ of the day)	38	42	44	47	49	50	51	+2.0% pa

High Case ERCE Brent Assumptions ($/bbl)	2H16E	2017E	2018E	2019E	2020E	2021E	2022E	2023E+
Real (Constant $, 2016)	53	64	73	80	86	90	90	90
Nominal ($ of the day)	53	65	76	85	93	99	101	+2.0% pa

Table 5.16: Shaikan Oil Price Discount to Brent Crude

	Shaikan Oil Price Discount to Brent Crude ($/stb, Real 2016)		
	Low	Base	High
2016	14.70	14.70	14.70
2017	12.90	12.90	12.90
2018	12.90	12.90	12.90
2019	11.30	14.50	16.80
2020	11.50	15.00	17.70
2021	11.50	15.30	18.30
2022	9.90	13.40	16.10
2023	9.90	13.40	16.10
2024	9.90	13.40	16.10
2025	9.90	13.40	16.10
2026	9.70	13.10	15.80
2027	9.80	13.20	15.90
2028	9.90	13.30	16.00
2029	9.90	13.40	16.10
2030	10.00	13.50	16.20
2031	10.10	13.50	16.30
2032	10.10	13.60	16.30
2033	10.20	13.70	16.40
2034	10.20	13.70	16.50
2035	10.20	13.70	16.50
2036	10.20	13.80	16.50
2037	10.30	13.80	16.60
2038	10.30	13.80	16.60
2039	10.30	13.90	16.60
2040	10.30	13.90	16.70
2041	10.40	13.90	16.70
2042	10.40	13.90	16.70
2043	10.40	14.00	16.80

Inflation and Cost Escalation. An annual inflation rate of 2.0% per annum has been applied. Capital and operating costs have been estimated as at 1 July 2016 real terms and inflated at the 2.0% per annum inflation rate, unless the Shaikan PSC stipulates otherwise. The currency of the Shaikan PSC is the US Dollar. All prices and costs have been denominated in US dollars and all cash flows calculated accordingly.

Discount Rate and Inflation. A 10% nominal discount rate, discounting to the mid-year point has been applied to all future net cash flows with effect from 1 July 2016. Discount rates of 5%, 15% and 20% have also been used to calculate the sensitivity of the economic metrics to the discount rate.

5.12.3. Economic Evaluation Results

The results of the economic evaluation are presented in the following sections. These constitute point forward discounted cash flows from 1 July 2016. Though net present values form an integral part of the fair market value estimations, without consideration for other economic criteria they are not to be constructed as ERCE’s opinion of fair market value.

Base Case Fiscal Terms and GKP oil quality discount forecast. Economic evaluations have been undertaken at the 1P, 2P and 3P Reserves levels for Shaikan. In addition, economic evaluation sensitivities to the oil price have been undertaken at the low case and high case price scenarios as sensitivities to the base case. ERCE has used the oil quality discount forecasts requested by GKP. Furthermore, net present value (NPV) sensitivities to Discount Rates ranging from 0.00% to 20.00% have been evaluated for the various economic price scenarios and Reserve levels stated above. A summary of the results is shown in Table 5.17. Summary cash flows at the 1P, 2P and 3P levels with the base case economic oil price with 58% working interest net to GKP are presented in Table 5.21 to Table 5.23.

Sensitivity 1: Historical Oil Quality Discount. (Constant oil quality discount price of $14.7 /stb.) In this sensitivity ERCE has replaced the Channoil oil quality differential with a single oil quality discount of $14.7 /stb in the 1P, 2P and 3P Reserves cases for Shaikan. A summary of the results is shown in Table 5.18. This sensitivity is included for comparative purposes as a discount price of $14.7 / stb has been used in all previous CPRs prepared by ERCE.

Sensitivity 2: Historical Fiscal Model Basis Scenario 1. (Undiluted 80% working interest and 40% CBP.) Economic sensitivities have been undertaken at the 1P, 2P and 3P Reserves levels for Shaikan with an undiluted GKP interest, i.e. no State or third party participation. This sensitivity assumes the CBP is 40% as described in the PSC as currently amended. A summary of the results is shown in Table 5.19. This sensitivity has been included for comparative purposes with precious CPRs prepared by ERCE.

Sensitivity 3: Historical Fiscal Model Basis Scenario 2. (Diluted 54.4% working interest and 40% CBP.) Economic sensitivities have been undertaken at the 1P, 2P and 3P Reserves levels for Shaikan with a fully diluted 54.4% GKP interest as described in the PSC as currently amended but before incorporation of the terms of the March Agreement, i.e. full State back in of 20% and Third Party participation of 15%. This sensitivity also assumes the CBP is 40% as described in the PSC as currently amended. A summary of the results is shown in Table 5.20. This sensitivity has been included for comparative purposes with precious CPRs prepared by ERCE.

Table 5.17: Economic Evaluation of Shaikan Reserves with 58% Diluted GKP Interest (with GKP oil price discount)

Shaikan Reserves Category	Economic Limit (Year)	GKP Net Entitlement (MMstb)	NPVs Net to GKP at 1 July 2016 (US$ million Nominal)					Gross Field Reserves (MMstb)
			NPV0 (US$ MM)	NPV5 (US$ MM)	NPV10 (US$ MM)	NPV15 (US$ MM)	NPV20 (US$ MM)	
Economic Base Case Oil Price								
1P	2029	79	812	501	306	180	99	238
2P	2043	161	3,067	1,759	1,089	708	477	622
3P	2043	203	4,615	2,374	1,364	849	559	951
Economic Low Case Oil Price								
1P	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
2P	2043	204	1,285	615	264	71	(37)	622
3P	2043	274	2,939	1,317	599	251	70	951
Economic High Case Oil Price								
1P	2035	89	1,698	1,169	829	603	449	286
2P	2043	137	3,846	2,275	1,475	1,019	738	622
3P	2043	171	5,576	2,960	1,778	1,171	825	951

Table 5.18: Sensitivity 1 - Historical Oil Quality Discount.

Sensitivity: $14.7 Differential	Economic Limit (Year)	GKP Net Entitlement (MMstb)	NPVs Net to GKP at 1 July 2016 (US$ million Nominal)					Gross Field Reserves (MMstb)
			NPV0 (US$ MM)	NPV5 (US$ MM)	NPV10 (US$ MM)	NPV15 (US$ MM)	NPV20 (US$ MM)	
Economic Base Case Oil Price								
1P	2029	78	737	449	268	151	76	238
2P	2043	163	3,014	1,724	1,063	688	460	622
3P	2043	205	4,551	2,334	1,336	828	541	951

Table 5.19: Sensitivity 2 - Historical Fiscal Model Basis Scenario 1

Shaikan Reserves Category	Economic Limit (Year)	GKP Net Entitlement (MMstb)	NPVs Net to GKP at 1 July 2016 (US$ million Nominal)					Gross Field Reserves (MMstb)
			NPV0 (US$ MM)	NPV5 (US$ MM)	NPV10 (US$ MM)	NPV15 (US$ MM)	NPV20 (US$ MM)	
Economic Base Case Oil Price								
1P	2029	100	893	542	321	180	89	238
2P	2043	203	3,427	1,960	1,208	782	522	622
3P	2043	256	5,144	2,641	1,514	938	614	951

Table 5.20: Sensitivity 3 - Historical Fiscal Model Basis Scenario 2

Shaikan Reserves Category	Economic Limit (Year)	GKP Net Entitlement (MMstb)	NPVs Net to GKP at 1 July 2016 (US$ million Nominal)					Gross Field Reserves (MMstb)
			NPV0 (US$ MM)	NPV5 (US$ MM)	NPV10 (US$ MM)	NPV15 (US$ MM)	NPV20 (US$ MM)	
Economic Base Case Oil Price								
1P	2029	68	611	368	216	119	56	238
2P	2043	142	2,531	1,459	904	587	392	622
3P	2043	179	3,737	1,940	1,121	699	458	951

Table 5.21: Cash Flow for Base Case Price Scenario and 1P Reserves with Base Case fiscal terms and GKP oil price discount

ERCE Shaikan 1P					Net to Gulf Keystone (GKP W.I. - Fully Diluted 58%)											
Year	Crude Oil Price	Gross Oil Production Rate	Gross Production	Gross Cumulative Production	Cost Recovery Revenue	Profit Petroleum Revenue	Operating Costs	Capex and Abandex	Bonuses and CBP	Net Cash Flow	Cumulative Net Cash Flow	NPV 5%	NPV 10%	NPV 15%	NPV 20%	GKP Entitlement Barrels
	(US$/stb)	(Mstb/d)	(MMstb/yr)	(MMstb)	(US$ MM)	(US$ MM)	(US$ MM)	(US$ MM)	(US$ MM)	(US$ MM)	(US$ MM)	(US$ MM)	(US$ MM)	(US$ MM)	(US$ MM)	(MMstb)
2016	46	34	6	6	38	15	(20)	(7)	(13)	13	13	13	12	12	12	2
2017	54	36	13	19	107	43	(48)	(35)	(13)	55	68	52	50	48	46	4
2018	62	36	13	33	132	53	(49)	(265)	(32)	(160)	(93)	(146)	(133)	(121)	(111)	4
2019	69	36	13	46	146	59	(65)	(369)	(18)	(247)	(340)	(214)	(186)	(163)	(143)	4
2020	74	53	19	65	229	93	(88)	(331)	(28)	(125)	(465)	(103)	(86)	(72)	(60)	6
2021	77	78	29	93	359	145	(107)	(150)	(44)	204	(262)	160	127	101	82	9
2022	79	77	28	122	377	152	(121)	(25)	(46)	338	76	252	191	146	113	9
2023	80	66	24	146	328	132	(123)	(61)	(40)	236	312	168	121	89	66	8
2024	82	57	21	166	288	116	(127)	(59)	(35)	184	496	124	86	60	43	7
2025	84	49	18	184	255	102	(132)	(37)	(31)	158	654	102	67	45	31	6
2026	85	43	16	200	229	89	(135)	(91)	(27)	65	720	40	25	16	11	5
2027	87	38	14	214	206	79	(142)	(55)	(24)	65	784	38	23	14	9	5
2028	89	34	12	227	188	71	(147)	(91)	(21)	(1)	783	(1)	(0)	(0)	(0)	4
2029	91	31	11	238	171	65	(154)	(32)	(19)	29	812	16	9	5	3	4
Total			**238**		**3,054**	**1,215**	**(1,457)**	**(1,611)**	**(389)**	**812**		**501**	**306**	**180**	**99**	**79**

Table 5.22: Cash Flow for Base Case Price Scenario and 2P Reserves with Base Case fiscal terms and GKP oil price discount

	ERCE Shaikan 2P				Net to Gulf Keystone (GKP W.I. - Fully Diluted 58%)											
Year	Crude Oil Price	Gross Oil Production Rate	Gross Production	Gross Cumulative Production	Cost Recovery Revenue	Profit Petroleum Revenue	Operating Costs	Capex and Abandex	Bonuses and CBP	Net Cash Flow	Cumulative Net Cash Flow	NPV 5%	NPV 10%	NPV 15%	NPV 20%	GKP Entitlement Barrels
	(US$/stb)	(Mstb/d)	(MMstb/yr)	(MMstb)	(US$ MM)	(US$ MM)	(US$ MM)	(US$ MM)	(US$ MM)	(US$ MM)	(US$ MM)	(US$ MM)	(US$ MM)	(US$ MM)	(US$ MM)	(MMstb)
2016	46	38	7	7	42	17	(20)	(7)	(13)	18	18	18	18	18	18	2
2017	54	38	14	21	113	46	(48)	(35)	(14)	62	81	59	57	54	52	5
2018	62	38	14	35	139	56	(49)	(265)	(33)	(151)	(70)	(137)	(125)	(114)	(105)	5
2019	69	38	14	49	154	62	(65)	(369)	(19)	(237)	(308)	(205)	(178)	(156)	(137)	5
2020	74	59	22	70	259	105	(89)	(314)	(31)	(70)	(378)	(58)	(48)	(40)	(34)	7
2021	77	101	37	107	467	188	(109)	(125)	(57)	365	(13)	286	227	181	147	12
2022	79	109	40	147	533	215	(124)	-	(64)	559	546	417	316	242	187	14
2023	80	109	40	187	543	217	(126)	(40)	(65)	529	1,075	376	271	199	148	14
2024	82	109	40	227	231	272	(132)	(40)	(82)	250	1,325	169	116	82	58	9
2025	84	109	40	267	158	277	(137)	(21)	(83)	194	1,518	125	82	55	38	7
2026	85	98	36	303	217	226	(140)	(77)	(68)	158	1,677	97	61	39	26	7
2027	87	89	32	335	190	207	(147)	(43)	(62)	145	1,821	85	51	31	19	7
2028	89	81	30	365	232	177	(152)	(80)	(53)	124	1,945	69	40	23	14	7
2029	91	75	27	392	181	171	(159)	(22)	(51)	120	2,065	63	35	19	11	6
2030	92	69	25	417	247	143	(163)	(84)	(43)	100	2,165	51	26	14	8	6
2031	94	64	23	441	211	139	(164)	(47)	(42)	98	2,263	47	23	12	6	5
2032	96	59	22	462	189	134	(165)	(24)	(40)	93	2,356	43	20	10	5	5
2033	98	55	20	482	212	119	(163)	(48)	(36)	83	2,440	36	17	8	4	5
2034	100	51	19	501	195	115	(164)	(31)	(34)	80	2,520	33	14	6	3	4
2035	102	48	18	519	189	109	(160)	(29)	(33)	76	2,596	30	12	5	2	4
2036	104	45	17	535	185	103	(158)	(27)	(31)	72	2,669	27	11	4	2	4
2037	106	42	15	551	179	98	(154)	(25)	(30)	69	2,738	25	9	4	1	4
2038	108	40	15	565	174	94	(151)	(24)	(28)	66	2,803	23	8	3	1	4
2039	110	38	14	579	170	90	(148)	(22)	(27)	63	2,866	20	7	3	1	3
2040	113	36	13	592	166	87	(145)	(21)	(26)	61	2,927	19	6	2	1	3
2041	115	34	12	604	162	83	(142)	(20)	(25)	58	2,985	17	5	2	1	3
2042	117	32	12	616	157	80	(138)	(19)	(24)	56	3,041	16	5	1	0	3
2043	119	30	5	622	79	38	(71)	(9)	(11)	26	3,067	7	2	1	0	1
2044	-	-	-	622	-	-	-	-	-	-	3,067	-	-	-	-	-
Total			**622**		**5,974**	**3,667**	**(3,581)**	**(1,868)**	**(1,124)**	**3,067**		**1,759**	**1,089**	**708**	**477**	**161**

Table 5.23: Cash Flow for Base Case Price Scenario and 3P Reserves with Base Case fiscal terms and GKP oil price discount

	ERCE Shaikan 3P				Net to Gulf Keystone (GKP W.I. - Fully Diluted 58%)											
Year	Crude Oil Price	Gross Oil Production Rate	Gross Production	Gross Cumulative Production	Cost Recovery Revenue	Profit Petroleum Revenue	Operating Costs	Capex and Abandex	Bonuses and CBP	Net Cash Flow	Cumulative Net Cash Flow	NPV 5%	NPV 10%	NPV 15%	NPV 20%	GKP Entitlement Barrels
	(US$/stb)	(Mstb/d)	(MMstb/yr)	(MMstb)	(US$ MM)	(US$ MM)	(US$ MM)	(US$ MM)	(US$ MM)	(US$ MM)	(US$ MM)	(US$ MM)	(US$ MM)	(US$ MM)	(US$ MM)	(MMstb)
2016	46	39	7	7	43	17	(20)	(7)	(13)	20	20	20	20	19	19	2
2017	54	39	14	22	117	47	(48)	(35)	(14)	67	87	64	61	58	56	5
2018	62	39	14	36	144	58	(49)	(247)	(33)	(128)	(41)	(116)	(106)	(97)	(89)	5
2019	69	39	14	50	158	64	(64)	(369)	(19)	(230)	(270)	(198)	(173)	(151)	(133)	5
2020	74	59	22	72	259	105	(88)	(295)	(31)	(50)	(321)	(41)	(34)	(29)	(24)	7
2021	77	101	37	109	467	188	(106)	(125)	(57)	368	47	288	228	183	148	12
2022	79	109	40	149	533	215	(121)	-	(64)	562	609	419	317	243	188	14
2023	80	109	40	189	541	214	(124)	(40)	(64)	528	1,137	375	271	198	147	14
2024	82	109	40	229	169	281	(129)	(40)	(84)	197	1,334	133	92	64	46	8
2025	84	109	40	269	176	271	(134)	(41)	(81)	190	1,523	122	80	54	37	8
2026	85	109	40	308	217	258	(140)	(77)	(77)	180	1,703	111	70	45	29	8
2027	87	109	40	348	190	259	(147)	(43)	(78)	182	1,885	106	64	39	24	7
2028	89	109	40	388	233	248	(153)	(80)	(74)	174	2,059	97	55	32	19	8
2029	91	109	40	428	250	243	(161)	(89)	(73)	170	2,229	90	49	28	16	8
2030	92	109	40	468	299	235	(170)	(129)	(70)	164	2,393	83	43	23	13	8
2031	94	109	40	508	268	244	(175)	(93)	(73)	171	2,564	82	41	21	11	8
2032	96	109	40	548	251	250	(180)	(71)	(75)	175	2,739	80	38	19	9	8
2033	98	109	40	588	255	250	(182)	(73)	(75)	175	2,914	76	35	16	8	8
2034	100	109	40	628	239	256	(186)	(53)	(77)	179	3,094	74	32	14	7	7
2035	102	109	40	667	238	258	(184)	(53)	(77)	181	3,274	72	30	13	6	7
2036	104	109	40	707	213	265	(185)	(28)	(80)	186	3,460	70	28	11	5	7
2037	106	109	40	747	209	267	(181)	(28)	(80)	187	3,647	67	25	10	4	7
2038	108	109	40	787	207	269	(179)	(28)	(81)	188	3,835	64	23	9	3	6
2039	110	109	40	827	205	270	(177)	(28)	(81)	189	4,024	62	21	8	3	6
2040	113	109	40	867	203	274	(175)	(28)	(82)	191	4,216	59	19	7	2	6
2041	115	99	36	903	197	246	(171)	(25)	(74)	172	4,388	51	16	5	2	6
2042	117	90	33	936	191	224	(168)	(23)	(67)	157	4,544	44	13	4	1	5
2043	119	82	15	951	95	101	(85)	(10)	(30)	71	4,615	19	5	2	1	2
2044	-	-	-	951	-	-	-	-	-	-	4,615	-	-	-	-	-
Total			**951**		**6,568**	**5,878**	**(3,881)**	**(2,162)**	**(1,787)**	**4,615**		**2,374**	**1,364**	**849**	**559**	**203**

5.13. Shaikan Prospective Resources

Within the Shaikan structure there are formations that are potentially hydrocarbon bearing that have not yet been penetrated by a well, or that have been penetrated by one or more wells, but have not been tested for the presence of moveable hydrocarbons and which are therefore prospective for further exploration. ERCE has evaluated two of these opportunities that were selected by GKP for which we have reported Prospective Resources. The formations are the Triassic age Kurre Chine Dolomite formation and the Cretaceous age Qamchuqa formation. Both prospects rely on the same E-W trending anticline which also traps the discovered resources on the block.

5.13.1. Kurre Chine Dolomite

The Kurre Chine Dolomite (KCD) prospect comprises a single interval which lies directly beneath the discovered resources encountered within the shallower Triassic reservoirs (KCA, KCB and KCC). The formation has been penetrated by two wells at Shaikan (Well SH-4 and Well SH-5B). In Well SH-4 the KCD was fully penetrated but no logs were acquired across the KCD due to the presence of a 'fish' in the hole. The open hole DST across the uppermost KCD (behind the fish) together with the lower KCC was inconclusive with regards to fluid flow from the KCD. The formation was only partly penetrated in Well SH-5B (130m section) and tested water.

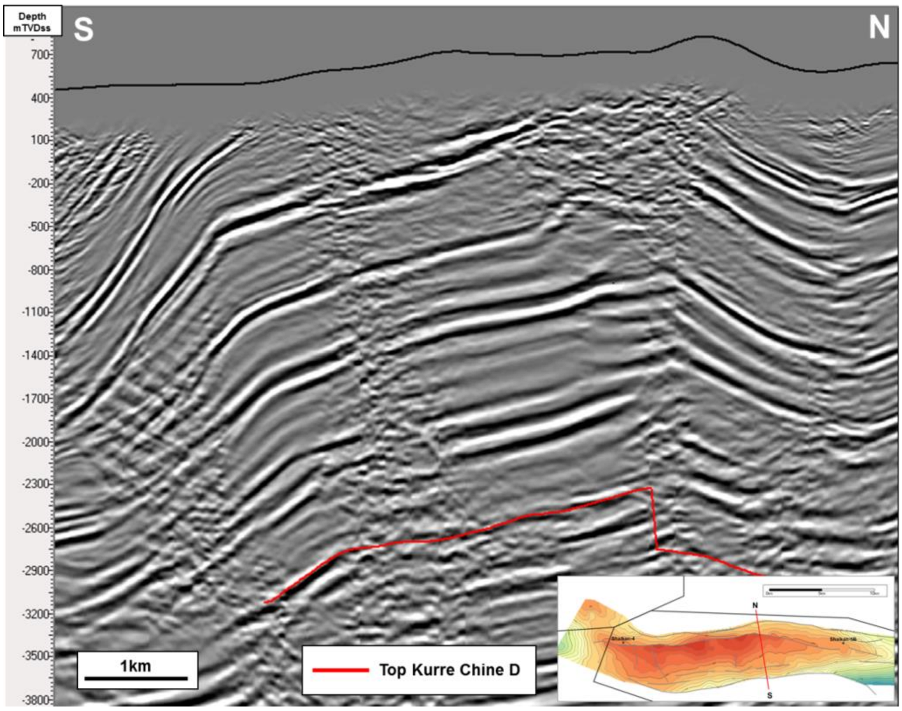

Figure 5.11: Dip Seismic Line, Kurre Chine D Prospect (PoSDM)

Depth Surfaces. The Top KCD is interpreted by GKP on the post-stack depth migrated 3D seismic data (PoSDM) volume (Figure 5.11), and ties the formation tops from penetrations by Well SH-4 and Well SH-5B. ERCE has reviewed the seismic interpretation carried out by GKP and has accepted the depth grid as a reasonable basis for estimating volumes (Figure 5.12). A seismically defined base reservoir pick (Top Geli Khana) is unreliable due to a lack of well penetrations, poor quality seismic data and a low impedance contrast. Instead, we estimated a range of gross reservoir thicknesses for the KCD and added them to the Top Kurre Chine D depth surface to define a base surface for use in our volumetric calculations. The low case thickness was estimated as 130m based on the incomplete interval drilled by well SH-5B (TD in formation), and our high case thickness was set to the full 190m interval seen in Well Ber Bahr-1 located some 30 kilometres to the north-west. The probable anhydritic interval at the top KCD is modelled as the top seal.

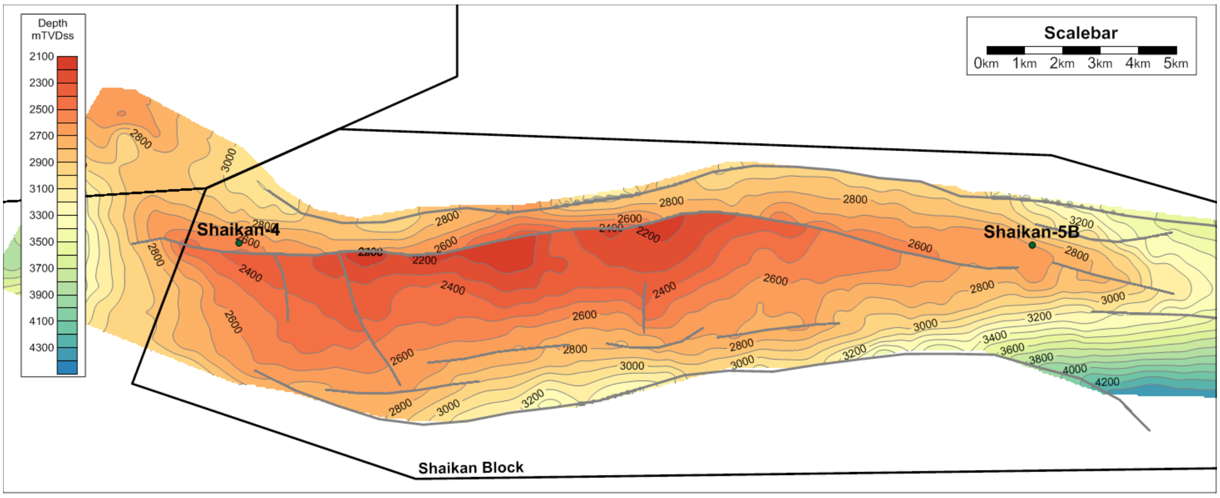

Figure 5.12: Shaikan Top Kurre Chine D Depth Map

Fluid Contacts. The KCD has been penetrated twice within Shaikan, by Well SH-4 and by Well SH-5B. Well SH-4 was tested (DST#1A) across the KCC/KCD boundary and produced some 440 stb/d of oil and 68 bbl/d of water. A PLT was run during the test, but the tool could not reach the KCD due to the fish. Nonetheless, the PLT log indicates that fluids were probably flowing around the fish, and they could possibly have come from the KCD, although this is not conclusive. It is also not clear what the make-up of the fluid was. The KCD interval was also tested in Well SH-5B (DST#1) and flowed water (1,800 bbl/d), defining a WUT at 2,768 mTVDSS.

ERCE used the formation tops from Well SH-4 and Well SH-5B (2,540 mTVDSS and 2,700 mTVDSS) as low and high contacts respectively, with a lognormal distribution fitted to resultant GRVs for input to probabilistic simulation.

Reservoir and Fluid Parameters. As with the shallower Triassic intervals, we modelled the KCD as a dual porosity system, with fracture and matrix hydrocarbon volume ranges summed probabilistically. Data for matrix reservoir properties are limited to a partial penetration by the water-bearing Well SH-5B and a complete section encountered by Well BB-1. In the same way as the evaluation in the overlying formations, ERCE has adopted the net pay parameters provided by GKP using a range of porosity cut-offs (3%, 4.5% and 7%) for the low, best and high cases.

The matrix net to gross ratio is significantly different between Wells SH-5B and BB-1. Our volumetric estimates are based on a lognormally distributed range between that estimated from Well SH-5B (2%) and that estimated from Well BB-1 (25%). Matrix porosity is reasonably consistent between Well SH-5B and Well BB-1, and we have based its range on varying the averages derived using porosity cut-off between 3% and 7%. Matrix hydrocarbon saturation is ranged around the values seen in the overlying KCC interval (~70%).

Table 5.24: Volumetric Input Parameters for Shaikan Kurre Chine D Prospect

Property	KCD		
	Low	Best	High
Matrix			
GRV (10^6 m^3)	3,581	5,639	8,881
N/G (fraction)	0.02	0.07	0.25
Phi (fraction)	0.05	0.07	0.09
So (fraction)	0.65	0.70	0.75
Bo (rb/stb)	1.77	1.95	2.17
Fractures			
GRV (10^6 m^3)	3,581	5,639	8,881
N/G (fraction)	0.85	0.90	0.95
Phi (fraction)	0.001	0.003	0.007
So (fraction)	1.00	1.00	1.00
Bo (rb/stb)	1.77	1.95	2.17

Fracture net to gross was defined using the same approach as the overlying formations by applying 50% shale and 50% anhydrite cut-offs. ERCE used the well log evaluation from Well SH-5B as the basis for this evaluation, but incorporated the shallower sections and results from Well BB-1 to define a range of uncertainty. Fracture porosity, hydrocarbon saturations, Bo and GOR ratio ranges were set to those used for the KCC.

Recovery Factors. Recovery factor ranges were estimated between 5% to 20% (lognormal) for the matrix and 60% to 80% (normal) for the fractures. These ranges match those used for discovered resources in the shallower Triassic intervals.

Risking. We have estimated a chance of success of 28% for the Kurre Chine D prospect. We have assigned a risk factor of 1.0 for source, which is proven in the area, 0.7 for reservoir, based on mixed results from the wells that have so far penetrated the KCD, 0.8 for trap and 0.5 for seal, based on the observation that the KCD lies directly below the KCC with little evidence for a separating seal.

5.13.2. **Qamchuqa**

The Qamchuqa formation comprises a thick carbonate interval within the Cretaceous, and lies directly above the discovered hydrocarbons encountered within the Cretaceous Sarmord, Garagu and Chia Gara formations. The formation is penetrated by all wells on the Shaikan structure. Good log suites are only available over the Qamchuqa in four wells (SH-1B, SH-5B, SH-6 and SH-8), which form the basis of the evaluation of matrix properties. While hydrocarbons are recorded in the composite log (cuttings and shows) and evaluated to be present from the electrical logs, no tests have been performed in the Qamchuqa formation in Shaikan.

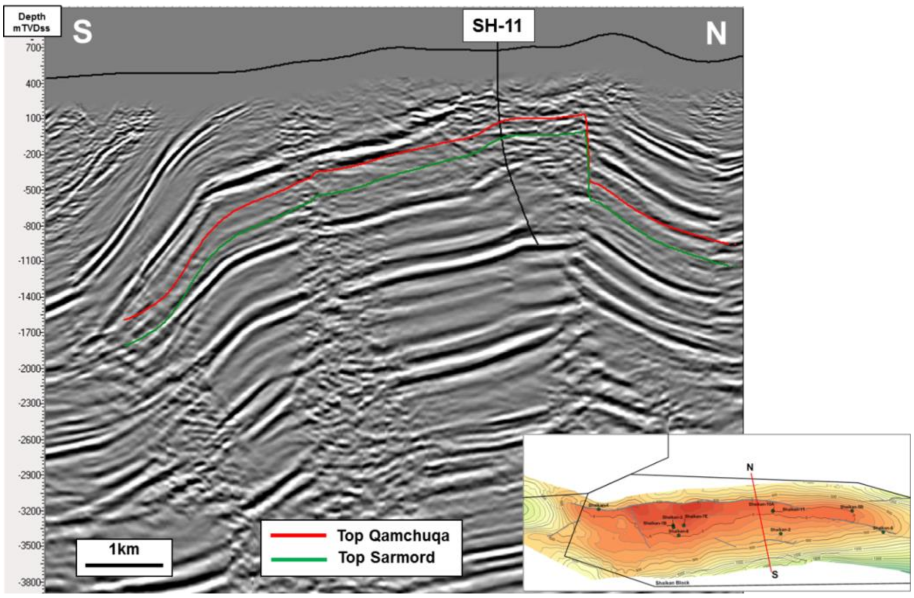

Figure 5.13: Dip Seismic Line, Qamchuqa Prospect (PoSDM)

Depth Surfaces. The top Qamchuqa horizon cannot be reliably mapped on current 3D seismic data due to poor shallow data quality and a lack of impedance contrast (Figure 5.13). A Top Sarmord seismic interpretation has been generated by GKP and ERCE has adopted this for the basis of our evaluation (Section 0). The grid was tied to the available formation tops with less than 15m correction being required, and forms the base reservoir surface for our volumetric calculations. ERCE derived the Top Qamchuqa depth surface (Figure 5.14) by isochoring upwards from the Top Sarmord depth grid provided by GKP. Well SH-7E was discounted as the formation top was deemed unreliable due to insufficient log data. The Top Qamchuqa is modelled as the top seal with a dip closed anticlinal structure.

Fluid isotherms and contacts. As discussed in Section 5.5.1, the production of oil from the Cretaceous reservoirs is interpreted to be dependent upon temperature and, consequently, depth. A range of isotherms below which oil is assumed recoverable (moveable) are set to match those employed by ERCE for the discovered hydrocarbons in the Cretaceous reservoirs of Shaikan (low case 550 mTVDSS, high case 390 mTVDSS). P90 STOIIP volumes were calculated down to a structural saddle at 608 mTVDSS, spilling NW towards the Sheikh Adi structural high.

A P10 OWC is identified on the logs of Well SH-6 at 790 mTVDSS. Although significantly deeper than the mapped structural spill, a deeper saddle is possible given the uncertain seismic response and resultant interpretation uncertainty. We estimated a P10 GRV using an ODT of 790 mTVDSS, areally truncated at the current saddle location. The low and high isotherms were combined deterministically with low and high case contacts to obtain P90 and P10 GRVs for the moveable oil volume, which were fitted to a lognormal distribution for probabilistic simulation.

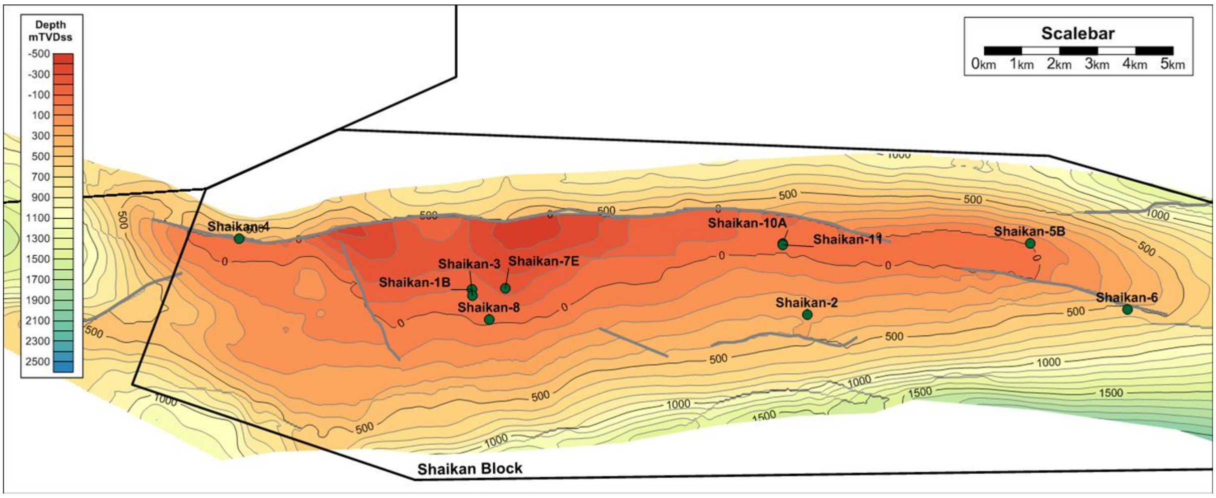

Figure 5.14: Shaikan Top Qamchuqa Depth Map

Reservoir and Fluid Parameters. As with the deeper Cretaceous intervals, the Qamchuqa is modelled as a dual porosity system, with fracture and matrix hydrocarbon ranges summed probabilistically. Data for matrix reservoir properties are based on the four wells in Shaikan that have good log suites (SH-1B, SH-5B, SH-6 and SH-8). In the same way as the evaluation in the overlying formations, ERCE has adopted the net pay parameters provided by GKP using a range of porosity cut-offs (3%, 4.5% and 7%) for the low, best and high cases.

Fracture net to gross ratio was defined using the same approach as the overlying formations, by applying 50% shale and 50% anhydrite cut-offs. In our evaluation, fracture porosity, hydrocarbon saturations, Bo and GOR ratio ranges were set to those used for the Sarmord, Garagu and Chia Gara.

Table 5.25: Volumetric Input Parameters for Shaikan Qamchuqa Prospect

Property	Qamchuqa		
	Low	Best	High
Matrix			
GRV (10^6 m^3)	1,940	4,689	11,331
N/G (fraction)	0.34	0.45	0.55
Phi (fraction)	0.09	0.10	0.12
So (fraction)	0.67	0.72	0.77
Bo (rb/stb)	1.00	1.00	1.00
Fractures			
GRV (10^6 m^3)	1,940	4,689	11,331
N/G (fraction)	1.00	1.00	1.00
Phi (fraction)	0.001	0.003	0.007
So (fraction)	1.00	1.00	1.00
Bo (rb/stb)	1.00	1.00	1.00

Recovery Factors. Recovery factors are estimated to be between 20% to 40% for the fractures. In a similar manner to the other Cretaceous reservoirs it is assumed that no oil will be recovered from the matrix.

Risking. Well SH-6 penetrated the full Qanchuqa interval below the depth of the isotherm used by ERCE to distinguish between moveable and immoveable oil in the other underlying Cretaceous reservoirs that we evaluated. Drilling and logging results of Well SH-6 indicate the formation to be hydrocarbon bearing, but no attempt was made to flow test the interval and the well results are inconclusive as to whether the hydrocarbons are moveable or not. The only prospect risk therefore relates to producibility and we have accordingly assigned a chance of success of 50%.

5.14. Shaikan In Place Volumes, Reserves and Resources

ERCE has estimated in place and recoverable volumes of oil and gas for Shaikan using a combination of probabilistic and deterministic methods. For each interval (Cretaceous, Jurassic and Triassic), ERCE calculated resources within each reservoir layer and/or zone separately for the matrix and the fractures using Monte Carlo simulation, in which input distribution functions of variables were probabilistically combined in the volumetric equations. The distribution functions were created by fitting normal, log-normal and triangular functions to the ranges of uncertainty in the various properties described in this report as low, best and high cases.

The ranges of uncertainty are quantified in Section 5.6 for GRV, Section 5.3.2 for fracture porosity, Section 5.4 for petrophysical properties, Section 5.7 for fluid properties and 5.10 for recovery factors. Resources in the matrix were then aggregated probabilistically across reservoir layers, while those for the fractures were aggregated deterministically. The reason for this is that the reservoir layers are considered independent with respect to matrix properties but not with respect to the primary uncertainty in the fractures, namely porosity. Total resources for the Jurassic were then estimated by adding matrix and fracture volumes deterministically. The Cretaceous and Triassic intervals were treated in a similar fashion.

The volumetric equations for oil used in this evaluation were:

$$STOIIP = C_1 \times \frac{GRV \times N/G \times \emptyset \times S_o}{B_o}$$

$$Oil\_Resources = STOIIP \times RF$$

where: $STOIIP$ = stock tank oil initially in place (MMstb)
C_1 = conversion constant (6.29 stb/m^3)
GRV = gross rock volume (MMm^3)
N/G = net to gross ratio (fraction)
$\emptyset$ = porosity (fraction)
S_o = oil saturation (fraction)
B_o = oil formation volume factor (rb/stb)
$Oil\_Resources$ = ultimate recovery of oil (MMstb)
RF = recovery factor (fraction)

The volumetric equations for free gas used in this evaluation were:

$$GIIP = C_2 \times GRV \times N/G \times \emptyset \times S_g \times E_g$$

$$Gas\_Resources = GIIP \times RF$$

where: $GIIP$ = gas initially in place (Bscf)
C_2 = conversion constant (35.317*10^{-3} Mscf/m^3)

S_g = gas saturation (fraction)
E_g = gas expansion factor (scf/rcf)
$Gas\_Resources$ = ultimate recovery of gas (Bscf)

Solution gas volumes were obtained by multiplying oil volumes with gas oil ratio (GOR) and adjusting for non-hydrocarbon components. Condensate volumes were estimated by multiplying gas volumes with CGR.

The production forecasts shown in Table 5.10, Table 5.11 and Table 5.12 for the Shaikan Phase 1-2 development extend to 30 June 2043 when the licence expires and have been used as input into an economic model, which has been used to estimate the economic cut-off dates for reporting Reserves (Section 5.12.3). GKP has informed ERCE that it is committed to implementing the development plan upon which these forecasts are based. Volumes estimated to be recoverable after the economic cut-off dates but before the end of licence expiry have been classified as Contingent Resources. The actual long term field production profiles will exceed those shown in Table 5.10, Table 5.11 and Table 5.12. Inevitably, some volumes of oil will not be recoverable within the licence period. ERCE has estimated these volumes and has reported them as technically recoverable volumes at gross field level, but has not classified then under the SPE PRMS and has not attributed any of these volumes to GKP as entitlement to volumes potentially recoverable from the field after expiry of the licence is not known.

GKP has identified tentative plans for further developments of Shaikan, with a view to recovering as much oil as possible within the licence period. These volumes have been classified by ERCE as Contingent Resources, contingent on the firming up of development plans.

In following these steps, ERCE made estimates of STOIIP and GIIP for discovered accumulations (Table 5.26) and prospects (Table 5.31) and have made estimates of recoverable volumes. We have classified our estimates of recoverable volumes as Reserves (Table 5.27), Contingent Resources (Table 5.28 and Table 5.29) and Prospective Resources (Table 5.32). Volumes estimated to be recoverable after licence expiry are reported as technically recoverable volumes at gross field level (Table 5.30).

Table 5.26: Summary of Discovered Oil and Gas Initially in Place for Shaikan

Field/ Licence	Formation	STOIIP (MMstb)			Free GIIP (Bscf)			Comments
		Low	Best	High	Low	Best	High	
Shaikan	Cretaceous above isotherm	475	553	645	0	0	0	No recovery reported
	Cretaceous below isotherm	653	842	1,344	0	0	0	
	Jurassic above 1,450 mSS	2,698	3,296	4,100	3	8	15	
	Jurassic below 1,450 mSS	1,791	2,159	2,677	0	0	0	
	Triassic	245	427	823	630	1,037	1,787	Gas is sour and rich

Table 5.27: Summary of Oil Reserves for Shaikan

Field	Formation	Gross Field Oil Reserves (MMstb)			GKP WI (%)	GKP Working Interest Oil Reserves (MMstb)			GKP Net Entitlement Oil Reserves (MMstb)		
		1P	2P	3P		1P	2P	3P	1P	2P	3P
Shaikan	Cretaceous	1	3	4	58.0	1	2	2			
Shaikan	Jurassic	219	575	883	58.0	127	333	512	79	161	203
Shaikan	Triassic	18	44	63	58.0	10	25	37			
Shaikan	**Total**	**238**	**622**	**951**	**58.0**	**138**	**360**	**551**	**79**	**161**	**203**

Table 5.28: Summary of Oil Contingent Resources for Shaikan

Field/ Licence	Formation	Gross Field Oil Contingent Resources (MMstb)			GKP WI (%)	GKP Net WI Oil Contingent Resources (MMstb)		
		1C	2C	3C		1C	2C	3C
Shaikan	Cretaceous	14	53	175	58.0	8	31	102
	Jurassic	97	80	340		56	46	197
	Triassic	29	106	347		17	61	201
Total		**140**	**239**	**862**		**81**	**138**	**500**

Table 5.29: Summary of Gas Contingent Resources for Shaikan

Field/ Licence	Formation	Gross Field Gas Contingent Resources (Bscf)			GKP WI (%)	GKP Net WI Gas Contingent Resources (Bscf)		
		1C	2C	3C		1C	2C	3C
Shaikan	Cretaceous	0	0	0	58.0	0	0	0
	Jurassic	102	305	772		59	177	448
	Triassic	292	648	1,583		169	376	918
Total		**394**	**953**	**2,355**		**228**	**553**	**1,366**

Note:

1) Gas volumes currently being produced from the Jurassic reservoirs are being flared.

Table 5.30: Summary of Technically Recoverable Oil Volumes After Licence Expiry

Field/ Licence	Formation	Gross Field Oil Technically Recoverbale Volumes (MMstb)		
		Low	Best	High
Shaikan	Cretaceous	0	0	0
	Jurassic	84	132	219
	Triassic	10	18	35
Total		**94**	**150**	**254**

Table 5.31: Summary of Undiscovered and Prospective Oil and Gas Initially in Place for Shaikan

Field/ Licence	Formation	STOIIP (MMstb)		
		Low	Best	High
Shaikan	Qamchuqa	484	1,099	2,584
	Triassic KCD	51	123	316

Notes

1) Oil has been intersected in the Shaikan Qanchuqa, but volumes are reported as 'prospective' because no flow test has been carried out.

Table 5.32: Summary of Prospective Resources for Shaikan

Block/ Licence	Prospect	Gross Field Oil Prospective Resources (MMstb)			GKP WI (%)	GKP Net WI Oil Prospective Resources (MMstb)			COS (%)
		Low	Best	High		Low	Best	High	
Shaikan	Qamchuqa	6	23	85	58.0	4	13	49	50
	Triassic KCD	17	42	105		10	24	61	28

6. SPE PRMS Definitions

This section contains extracts from the Petroleum Resources Management System (SPE PRMS), dated 2007, sponsored by the Society of Petroleum Engineers (SPE), the American Association of Petroleum Geologists (AAPG), the World Petroleum Council (WPC) and the Society of Petroleum Evaluation Engineers (SPEE).

6.1. Preamble

Petroleum resources are the estimated quantities of hydrocarbons naturally occurring on or within the Earth's crust. Resource assessments estimate total quantities in known and yet-to-be-discovered accumulations; resources evaluations are focused on those quantities that can potentially be recovered and marketed by commercial projects. A petroleum resources management system provides a consistent approach to estimating petroleum quantities, evaluating development projects, and presenting results within a comprehensive classification framework.

International efforts to standardize the definitions of petroleum resources and how they are estimated began in the 1930s. Early guidance focused on Proved Reserves. Building on work initiated by the Society of Petroleum Evaluation Engineers (SPEE), SPE published definitions for all Reserves categories in 1987. In the same year, the World Petroleum Council (WPC, then known as the World Petroleum Congress), working independently, published Reserves definitions that were strikingly similar. In 1997, the two organizations jointly released a single set of definitions for Reserves that could be used worldwide. In 2000, the American Association of Petroleum Geologists (AAPG), SPE, and WPC jointly developed a classification system for all petroleum resources. This was followed by additional supporting documents: supplemental application evaluation guidelines (2001) and a glossary of terms utilized in resources definitions (2005). SPE also published standards for estimating and auditing reserves information (revised 2007).

These definitions and the related classification system are now in common use internationally within the petroleum industry. They provide a measure of comparability and reduce the subjective nature of resources estimation. However, the technologies employed in petroleum exploration, development, production, and processing continue to evolve and improve. The SPE Oil and Gas Reserves Committee works closely with other organizations to maintain the definitions and issues periodic revisions to keep current with evolving technologies and changing commercial opportunities.

The PRMS consolidates, builds on, and replaces guidance previously contained in the 1997 Petroleum Reserves Definitions, the 2000 Petroleum Resources Classification and Definitions publications, and the 2001 "Guidelines for the Evaluation of Petroleum Reserves and Resources"; the latter document remains a valuable source of more detailed background information, and specific chapters are referenced herein.

These definitions and guidelines are designed to provide a common reference for the international petroleum industry, including national reporting and regulatory disclosure agencies, and to support petroleum project and portfolio management requirements. They are intended to improve clarity in global communications regarding petroleum resources.

It is understood that these definitions and guidelines allow flexibility for users and agencies to tailor application for their particular needs; however, any modifications to the guidance contained herein should be clearly identified. The definitions and guidelines contained in this document must not be construed as modifying the interpretation or application of any existing regulatory reporting requirements.

The estimation of petroleum resource quantities involves the interpretation of volumes and values that have an inherent degree of uncertainty. These quantities are associated with development projects at various stages of design and implementation. Use of a consistent classification system enhances comparisons between projects, groups of projects, and total company portfolios according to forecast production profiles and recoveries. Such a system must consider both technical and commercial factors that impact the project's economic feasibility, its productive life, and its related cash flows.

6.2. 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 sulfide and sulfur. 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 10.1 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 that will be developed and reach commercial producing status. The following definitions apply to the major subdivisions within the resources classification:

TOTAL PETROLEUM INITIALLY-IN-PLACE is 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 is 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.

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.

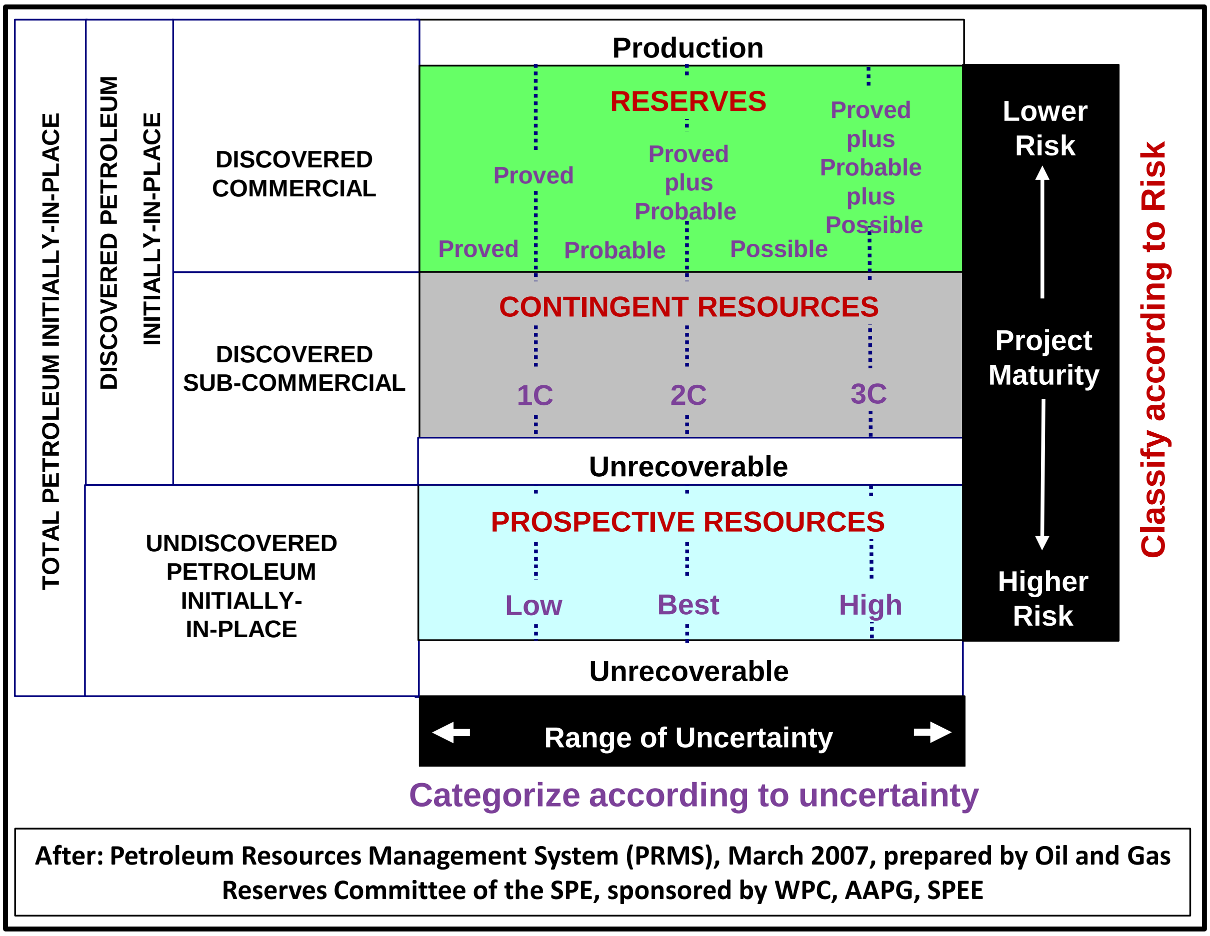

Figure 6.1: SPE PRMS Resources Classification Framework

RESERVES are 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 categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by development and production status.

CONTINGENT RESOURCES are 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 categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their economic status.

Note that for resources to be classified as Contingent Resources they must be discovered

UNDISCOVERED PETROLEUM INITIALLY-IN-PLACE is that quantity of petroleum estimated, as of a given date, to be contained within accumulations yet to be discovered.

PROSPECTIVE RESOURCES are 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. Prospective Resources can be sub-classified as Prospects, Leads and Plays as follows:

Prospect: A potential accumulation that is sufficiently well defined to represent a viable drilling target.

Lead: A potential accumulation that is currently poorly defined and requires more data acquisition and/or evaluation in order to be classified as a prospect.

Play: A prospective trend of potential prospects, but which requires more data acquisition and/or evaluation in order to define specific leads or prospects.

UNRECOVERABLE is 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.

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 specialized 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

6.3. Determination of Discovery Status

A discovery is one petroleum accumulation, or several petroleum accumulations collectively, for which one or several exploratory wells have established through testing, sampling, and/or logging the existence of a significant quantity of potentially moveable hydrocarbons. In this context, “significant” implies that there is evidence of a sufficient quantity of petroleum to justify estimating the in-place volume demonstrated by the well(s) and for evaluating the potential for economic recovery. Estimated recoverable quantities within such a discovered (known) accumulation(s) shall initially be classified as Contingent Resources pending definition of projects with sufficient chance of commercial development to reclassify all, or a portion, as Reserves.

Where in-place hydrocarbons are identified but are not considered currently recoverable, such quantities may be classified as Discovered Unrecoverable, if considered appropriate for resource management purposes; a portion of these quantities may become recoverable resources in the future as commercial circumstances change or technological developments occur.

6.4. Determination of Commerciality

Discovered recoverable volumes (Contingent Resources) may be considered commercially producible, and thus Reserves, if the entity claiming commerciality has demonstrated firm intention to proceed with development and such intention is based upon all of the following criteria:

- Evidence to support a reasonable timetable for development.
- A reasonable assessment of the future economics of such development projects meeting defined investment and operating criteria:
- A reasonable expectation that there will be a market for all or at least the expected sales quantities of production required to justify development.
- Evidence that the necessary production and transportation facilities are available or can be made available:
- Evidence that legal, contractual, environmental and other social and economic concerns will allow for the actual implementation of the recovery project being evaluated.

To be included in the Reserves class, a project must be sufficiently defined to establish its commercial viability. There must be a reasonable expectation that all required internal and external approvals will be forthcoming, and there is evidence of firm intention to proceed with development within a reasonable time frame. A reasonable time frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While 5 years is recommended as a benchmark, a longer time frame could be applied where, for example, development of economic projects are deferred at the option of the producer for, among other things, market-related reasons, or to meet contractual or strategic objectives. In all cases, the justification for classification as Reserves should be clearly documented.

To be included in the Reserves class, there must be a high confidence in the commercial producibility of the reservoir as supported by actual production or formation tests. In certain cases, Reserves may be assigned on the basis of well logs and/or core analysis that indicate that the subject reservoir is hydrocarbon-bearing and is analogous to reservoirs in the same area that are producing or have demonstrated the ability to produce on formation tests.

6.5. 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 (P90) that the quantities actually recovered will equal or exceed the low estimate.
- There should be at least a 50% probability (P50) that the quantities actually recovered will equal or exceed the best estimate.
- There should be at least a 10% probability (P10) that the quantities actually recovered will equal or exceed the high estimate.

When using the deterministic scenario method, typically there should also be low, best, and high estimates, where such estimates are based on qualitative assessments of relative uncertainty using consistent interpretation guidelines. Under the deterministic incremental (risk-based) approach, quantities at each level of uncertainty are estimated discretely and separately.

These same approaches to describing uncertainty may be applied to Reserves, Contingent Resources, and Prospective Resources. While there may be significant risk that sub-commercial and undiscovered accumulations will not achieve commercial production, it useful to consider the range of potentially recoverable quantities independently of such a risk or consideration of the resource class to which the quantities will be assigned.

6.6. **Category Definitions and Guidelines**

Evaluators may assess recoverable quantities and categorize results by uncertainty using the deterministic incremental (risk-based) approach, the deterministic scenario (cumulative) approach, or probabilistic methods. In many cases, a combination of approaches is used.

Use of consistent terminology (Figure 10.1) promotes clarity in communication of evaluation results. For Reserves, the general cumulative terms low/best/high estimates are denoted as 1P/2P/3P, respectively. The associated incremental quantities are termed Proved, Probable and Possible. Reserves are a subset of, and must be viewed within context of, the complete resources classification system. While the categorization criteria are proposed specifically for Reserves, in most cases, they can be equally applied to Contingent and Prospective Resources conditional upon their satisfying the criteria for discovery and/or development.

For Contingent Resources, the general cumulative terms low/best/high estimates are denoted as 1C/2C/3C respectively. For Prospective Resources, the general cumulative terms low/best/high estimates still apply. No specific terms are defined for incremental quantities within Contingent and Prospective Resources.

Without new technical information, there should be no change in the distribution of technically recoverable volumes and their categorization boundaries when conditions are satisfied sufficiently to reclassify a project from Contingent Resources to Reserves. All evaluations require application of a consistent set of forecast conditions, including assumed future costs and prices, for both classification of projects and categorization of estimated quantities recovered by each project.

The following summarizes the definitions for each Reserves category in terms of both the deterministic incremental approach and scenario approach and also provides the probability criteria if probabilistic methods are applied.

Proved Reserves are those quantities of petroleum, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under defined economic conditions, operating methods, and government regulations. 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.

Probable Reserves are those additional Reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves. It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved plus Probable Reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate.

Possible Reserves are those additional reserves which analysis of geoscience and engineering data suggest are less likely to be recoverable than Probable Reserves. The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved plus Probable plus Possible (3P) Reserves, which is equivalent to the high estimate scenario. In this context, when probabilistic methods are used, there should be at least a 10% probability that the actual quantities recovered will equal or exceed the 3P estimate.

Uncertainty in resource estimates is best communicated by reporting a range of potential results. However, if it is required to report a single representative result, the “best estimate” is considered the most realistic assessment of recoverable quantities. It is generally considered to represent the sum of Proved and Probable estimates (2P) when using the deterministic scenario or the probabilistic assessment methods. It should be noted that under the deterministic incremental risk-based) approach, discrete estimates are made for each category, and they should not be aggregated without due consideration of their associated risk.

7. Nomenclature

7.1. Units and their abbreviations

°C	degrees Celsius
°F	degrees Fahrenheit
bbl	barrel
bbl/d	barrels per day
Bscf	thousands of millions of standard cubic feet
boe	barrels of oil equivalent, where 6000 scf of gas = 1 bbl of oil
cm	centimetres
cp	centipoises
ft	feet
g	gram
km	kilometres
m	metres
M MM	thousands and millions respectively
m/s	metres per second
m/s*g/cc	AI units
md	millidarcy
mMDRKB	metres measured depth below Kelly Bushing
mTVDSS	metres true vertical depth subsea
ppm	parts per million
psia	pounds per square inch absolute
psig	pounds per square inch gauge
pu	porosity unit
rcf	cubic feet at reservoir conditions
rb	reservoir barrels
scf	standard cubic feet measured at 14.7 pounds per square inch and 60 degrees Fahrenheit
scf/d	standard cubic feet per day
stb	a stock tank barrel which is 42 US gallons measured at 14.7 pounds per square inch and 60 degrees Fahrenheit
stb/d	stock tank barrels per day

7.2. Resources Categorisation

The following are SPE PRMS terms, defined in Section 6:

1P	Proved, a low estimate category of Reserves
2P	Proved + Probable, a best estimate category of Reserves
3P	Proved + Probable +Possible, a high estimate category of Reserves
1C	a low estimate category of Contingent Resources
2C	a best estimate category of Contingent Resources
3C	a high estimate category of Contingent Resources
Low	a low estimate category of Prospective Resources also used as a generic term to describe a low or conservative estimate
Best	a best estimate category of Prospective Resources also used as a generic term to describe a best, or mid estimate
High	high estimate category of Prospective Resources also used as a generic term to describe a high or optimistic estimate

7.3. Terms and their abbreviations

AVO	amplitude variation with offset
Bo	oil shrinkage factor or formation volume factor, in rb/stb
Capex	capital expenditure
CGR	condensate gas ratio
COS	geological chance of success for prospective resources
CPI	computer processed information log
DST	drill stem test
Eg	gas expansion factor
FDP	field development plan, dated 2013
FDP Update	field development plan, dated December 2015
FEED	front end engineering and design
FID	final investment decision
FVF	formation volume factor
FWL	free water level
GDT	gas down to
GEF	gas expansion factor
GIIP	gas initially in place
GOC	gas oil contact
GR	gamma ray
GRV	gross rock volume
KB	kelly bushing
k	permeability
kh	permeability thickness
Listing CPR	CPR dated March 2014 in connection with the listing of GKP's
MD	measured depth
MDT	modular formation dynamic tester
MSL	mean sea level
N/G	net to gross ratio
NMO	normal move-out
NPV_{xx}	net present value at xx% discount rate
Opex	operating expenditure
ODT	oil down to
OWC	oil water contact
Phi	porosity
Phie	effective porosity
Phit	total porosity
PSC	production sharing contract
PVT	pressure volume temperature experiment
RFT	repeat formation tester
Rs	solution gas oil ratio
Rt	true resistivity
Rw	formation water resistivity
SCAL	special core analysis
Sg	gas saturation
So	oil saturation
s SRD	seconds below seismic reference datum
STOIIP	stock tank oil initially in place
Sw	water saturation
TD	total depth
TVD	true vertical depth
TWT	two way time
Vsh	shale volume
WGR	water gas ratio

WUT	water up to