Palm Valley 13

Well Completion Report (Interpretative) Revision 2

21 August 2018 – 13 October 2018

OL3

Amadeus Basin

Northern Territory

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1 LIST OF ABBREVIATIONS

Abbreviation	Full Text	Abbreviation	Full Text
AHD	Australian Height Datum	MMscf/d	Million standard cubic feet per day
API	American Petroleum Institute	m RT	Metres Rotary Table
Az	Azimuth	m SS	Metres Sub Sea
bbls/hr	Barrels per hour	mV	Millivolts
bbls	Barrels	MWD	Measurements while drilling
BTC	Buttress connection	N_2	Nitrogen
CBL	Cement Bond Log	NPT	Non-Productive Time
C1	Methane	NA	Not Applicable
C2	Ethane	O_2	Oxygen
DP	Drill Pipe	OL	Operating Lease
EMW	Estimated Mud Weight	°	Degrees
FIT	Formation Integrity Test	ppf	Pounds per foot
Fm	Formation	ppg	Pounds per gallon
ft^3/sk	Cubic feet per sack	psi	Pounds per square inch
GOC	Gas-Oil Contact	PV1	Palm Valley 1
HKW	Highest Known Water	PV2	Palm Valley 2
Hrs	Hours	PV6b	Palm Valley 6b
in	Inches	PV7	Palm Valley 7
Inc	Inclination	PV10	Palm Valley 10
KCl	Potassium Chloride	PV13	Palm Valley 13
kg	Kilogram	QTY	Quantity
km	Kilometres	Slts	Siltstone
lb/ft	Pounds per foot	Sst	Sandstone
LCM	Loss control materials	TD	Total Depth
LS2	Lower Stairway 2 Sandstone	TVD	True Vertical Depth
m	Metres	TVDGL	True Vertical Depth from Ground Level
m BRT	Metres Below Rotary Table	TVT	True Vertical Thickness

2 INTRODUCTION

The Palm Valley Gas Field is situated within the Amadeus Basin approximately 130 km west-southwest of Alice Springs (Figure 1). It is a doubly plunging anticline with surface expression of approximately 350m and an anticlinal structural axis that can be traced for over 30 km. The discovery well, Palm Valley 1, was drilled in 1965, and since then 10 additional wells have been drilled. The gas field is classified as a Type 2 fractured reservoir, meaning that a natural fracture network provides permeability both laterally and vertically to a low porosity/permeability rock matrix. The field produces dry gas with a highest known water (HKW) of 1250 m SS.

The Palm Valley Field is currently on production with ~10MMscf/d production capacity from high permeability natural fractures and very low permeability matrix of the Lower Stairway and Pacoota Sandstones. The Palm Valley 13 (PV13) well targeted areas of high natural fracture density within the Lower Stairway Sandstone, Horn Valley Siltstone and Pacoota Sandstone. The well was drilled highly deviated to intersect the target horizons and as many natural fractures as possible.

3 PALM VALLEY 13 SUMMARY

PV13 targeted an area of predicted high natural fracture density within the Pacoota Sandstone and reached total depth after encountering encouraging gas flows to the northeast of PV13 surface location (Figure 2 and Figure 3). Natural fractures at the Palm Valley Gas Field are fold and fault related so that their orientation, distribution and intensity can be predicted. Fold related fractures are related to bedding orientation with the fractures predominantly oriented at a high angle to bedding. To maximise well deliverability and performance, the PV13 well trajectory incorporated a highly deviated section in order to increase number of fractures penetrated. The PV13 well drilled the target section with air/mist to avoid fluid damage, as well, a downhole deployment valve allowed for the reservoir section to remain fluid free upon tripping and completion.

The geological rational behind choosing the well location was to intersect the Lower Stairway Sandstone, Horn Valley Siltstone and Pacoota Sandstone at a highly deviated angle to bedding within a zone of predicted high fracture density. The surface location of the target is approximately 900 m East of PV10 (Figure 2). As such, the well consisted of a highly deviated section that targeted areas of increased natural fracture density within the Lower Stairway Sandstone, Horn Valley Siltstone and Pacoota Sandstone.

PV13 was spudded on August 21st, 2018 and was completed with tubing and packer and awaiting tie in to the Palm Valley facilities on October 18th, 2018 after intersecting gas flows of 12MMscf/d within the Pacoota P1 Sandstone. PV13 began producing on the 23rd of May 2019 and is currently on production.

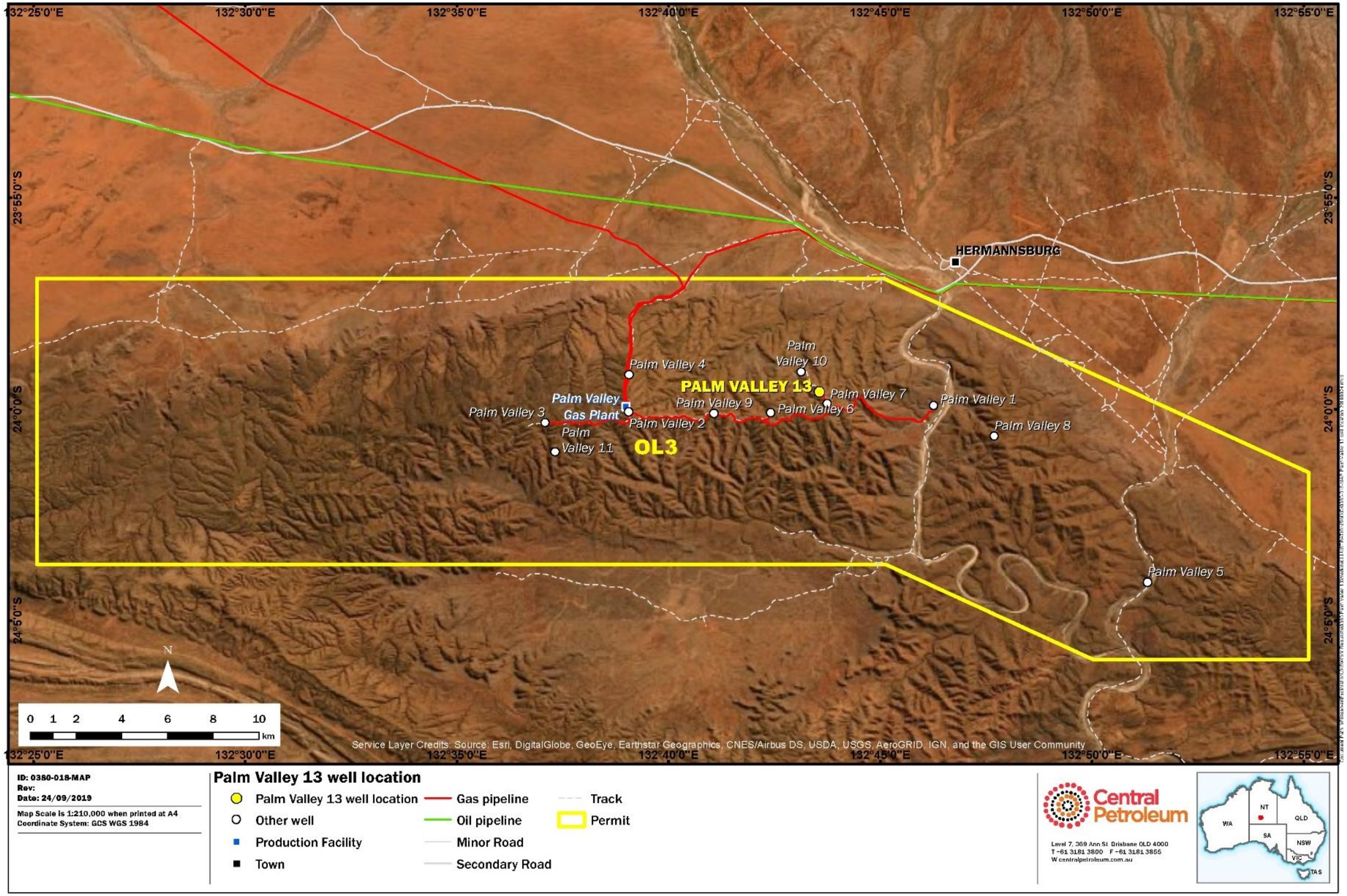

Figure 1 — PV13 locality map

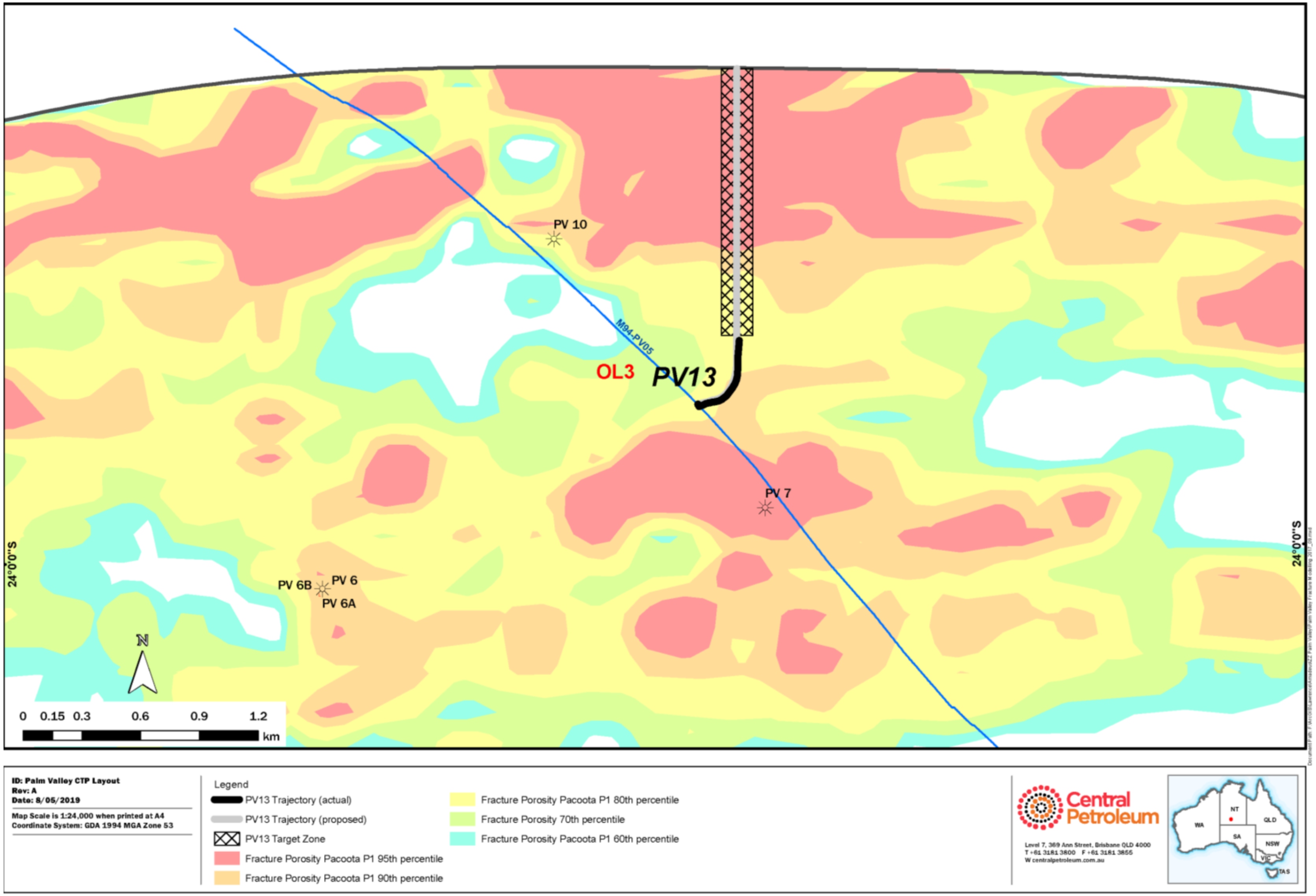

Figure 2 — The primary target for PV13 is a zone of predicted high fracture density within the Pacoota P1, approximately 900 m north of PV7 at a depth of ~1830 mGL

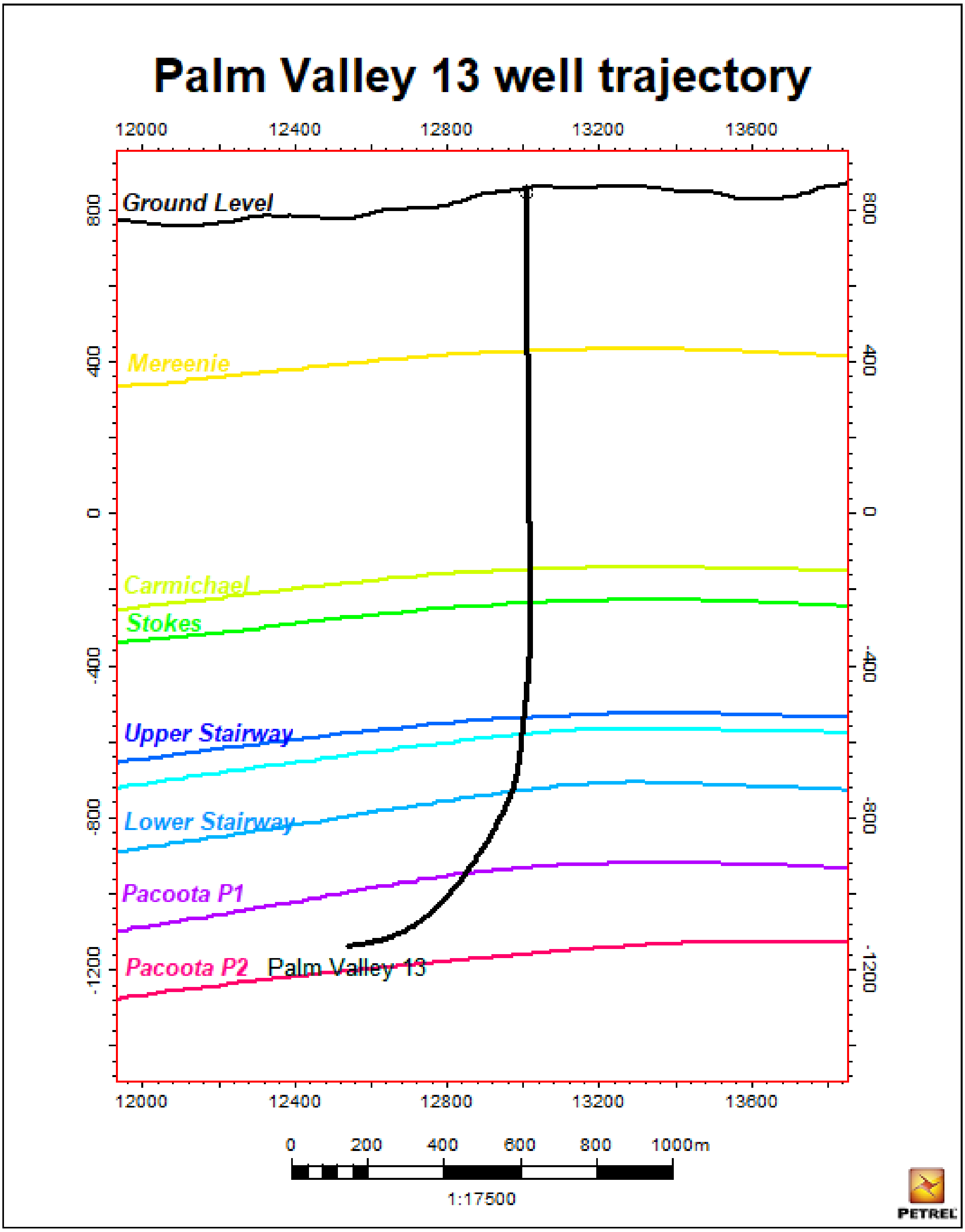

Figure 3 — Palm Valley 13 Well Trajectory

4 GENERAL DATA

Table 1: Palm Valley 13 Well Index Sheet

Well Name	Palm Valley 13	Petroleum Title	OL3	Basin	Amadeus
Well Purpose	Appraisal	Status	Suspended	Parent Well Name, if any	
Spud Date	21/08/2018	TD Date	13/10/2018	Rig Release Date	18/10/2018

Primary Objective	Pacoota P1 Sandstone	Rig(s) Name	Ensign 932
Secondary Objective	NA	100K Map Sheet	Hermannsburg 5450

Total Depth		MD	TVD
	Driller	2242.00	1988.70
	Logger	NA	NA

Side-Track Kick-off Depth, if applicable	NA

Location *(GDA94 Datum with GRS80 Ellipsoid using MGA94 Grid)*	Coordinates	Surface	Bottom Hole
	Latitude	23°59'35.2819" S	23°59'20.6240" S
	Longitude	132°43'33.4332" E	132°43'41.5524" E
Zone	Easting	268 651.098	268 873.350
53	Northing	7 344 666.120	7 345 120.852

Drill Datum	
■ DF ❑ RT ❑ KB	Elevation Datum: AHD GL Elevation: 843.04m Drill Datum Elevation: 848.89m

Seismic Station, if applicable	Survey	Inline	Xline
	M94		PV-05
	Shot point		36

Well Summary

The Palm Valley 13 well was spudded on 21 August 2018 targeting gas in the Lower Stairway and Pacoota P1 Sandstone in an area of predicted high natural fracture density. The well was drilled directionally into the Horn Valley Siltstone with water-based and air/foam mud, where a 7" intermediate liner was cemented. Gas shows were observed in the Lower Stairway Sandstone and Horn Valley Siltstone while drilling with air/foam with a flow test (0.02MMscf/d) performed before the 7" intermediate liner was run. The well was then drilled out with air/foam into the Pacoota P1 Sandstone with the aim to maximize connection with any natural fractures. An increase in gas shows at 1946m MD necessitated a production test which recorded 0.56MMscf/d. Subsequent drilling observed other increases in gas shows with production tests ranging between 10.7MMscf/d and 13.6MMscf/d until TD of 2242.00m MD. 3-1/2' tubing and a packer were run and the well suspended for future facilities tie-in. The rig was released on 18 November 2018. PV13 began producing on the 23rd of May 2019 and is currently on production.

Hole and Casing Design (Drillers Depths)						Drilling Fluid	
Type	Hole Size	Depth (m MD)	Casing Size	Shoe m MD	Shoe m TVD	Hole Size	Type
Conductor 1	24 inch	23.5	20 inch	23.5	23.5	24 inch	WBM – Gel
Conductor 2	17.5 inch	249.0	23.375 inch	248.9	248.9	17.5 inch	WBM – KCl/Gel
Surface	12.25 inch	1119.0	9.625 inch	1116.5	1116.43	12.25 inch	WBM – KCl/Gel
Intermediate Liner	8.5 inch	1845.0	7 inch	1842.0	1779.6	8.5 inch	WBM – KCl/Gel Air/Foam
						6.125 inch	Air/Foam

Stratigraphy – Formation Tops (Loggers Depths)			
Formation	Depth		
	m MD	m TVD	m TVDGL
Hermannsburg Sandstone	5.85	5.85	0.0
Park Siltstone	389.0	389.0	383.15

Formation Evaluation			
Run	Measurement	Depth Interval	
		From (m MD)	To (m MD)
1	CBL - 9.625" casing	0.00	1124.31
2	CBL – 7" liner	542.96	1856.03

Mereenie Sandstone	423.0	423.0	417.15	3	MWD – Gamma Ray	1842.00	2242.00
Carmichael Sandstone	998.0	998.0	992.15		MWD - Temperature	1842.00	2242.00
Stokes Siltstone	1082.0	1082.0	1076.15		MWD – Rate of Penetration	1842.00	2242.00
Upper Stairway Sst	1412.0	1407.0	1401.15				
Middle Stairway Sst	1437.0	1430.9	1425.05				
Lower Stairway Sst	1608.0	1584.1	1578.25				
Horn Valley Siltstone	1761.0	1714.7	1708.85				
Pacoota P1 Sandstone	1864.0	1797.3	1791.45				
Total Depth	2242.0	1988.7	1982.85				

Mud Logging	Formation Testing (DST)	DFIT	☐ Yes ■ No
Total Gas and C1-C5 chromatograph from 0 m MD to 2242.0 m MD	No DST's were run, however a flow tests while drilling with air/foam were performed.	HF	☐ Yes ■ No

Coring	Hydrocarbon Shows
NA	1455m MD to 1946m MD – up to 1% mud gas, flow rate of 0.56MMscfd in the Pacoota P1 1946m MD to 2242m MD – mud gas sensor reading 100% at 2022m MD, flow rates from 10.7 - 13.6MMscfd while drilling with air/foam through the Pacoota P1

Completion
3-1/2' tubing and a packer were run and the well suspended for future facilities tie-in. The rig was released on 18 November 2018.

5 DRILLING

5.1 CASING AND DRILLING DETAILS

Table 2: PV13 casing details

FINAL WELL CONSTRUCTION									
Interval	Hole Specifications			Casing Specifications					
	Hole Size	From	To	OD	Weight	Grade	Thread	Casing Top	Shoe Depth
	[in]	[m RT]	[m RT]	[in]	[lb/ft]			[m RT]	[m RT]
Conductor – 1	24	5.85	23.5	20	94.0		Welded	5.85	23.5
Conductor – 2	17-1/2	23.5	249.0	13-3/8	54.5	K-55	BTC	5.85	248.9
Surface	12-1/4	249.0	1119.0	9-5/8	36.0	K-55	BTC	5.85	1116.5
				9-5/8	43.5	N-80	BTC	619.2	698.0
Intermediate - Liner	8-1/2	1119.0(MD) 1119.0(TVD)	1845.0(MD) 1782.0(TVD)	7	26.0	P-110	BTC	641.8(MD) 641.8(TVD)	1842.0(MD) 1779.6(TVD)
Production	6-1/8	1845.0(MD) 1782.0(TVD)	2242.0(MD) 1988.7(TVD)	Open Hole: 1842.0 – 2242.0m (MD), 1779.6 – 1988.7m (TVD)					

5.2 PALM VALLEY 13 TIME DEPTH CURVE

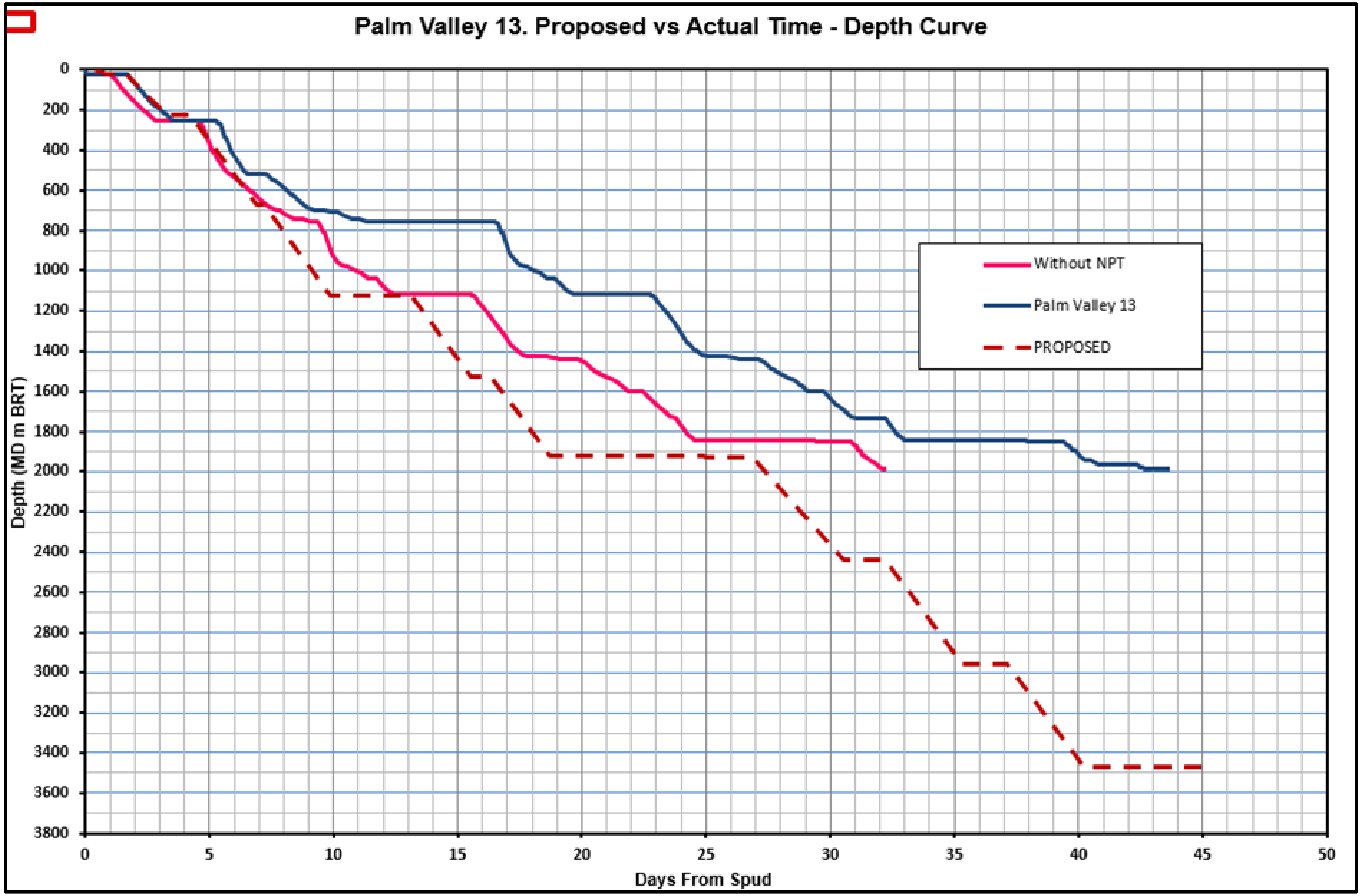

Figure 4 — Palm Valley 13 Time Depth curve

The PV13 time depth curve as depicted in Figure 4 presents three series of data. The dashed red line depicts the original well "proposed" time against depth relationship. It shows that the original well design was to drill to a measured depth over a 45-day period. The periods represented by a constant depth over several day periods are activities such as running casing where there is no increase in well depth. While a constant drilling rate was assumed from reviewing previous drilling at Palm Valley. The solid blue line represents the actual time depth curve for PV13. It portrays that the well was drilled in just under 45 days. Drilling did not continue to the original proposed measured depth because significant gas flows had been achieved. This blue curve also includes all non-productive time (NPT) such as premature bit and motor wear and tool string failure and fishing operations. The solid magenta line represents the actual time depth curve for PV13 with the NPT time removed. This is used internally to assist with engineering optimisation for future wells.

5.3 DEVIATION SURVEYS

Table 3: Deviation survey

DIRECTIONAL SURVEY			
MD	TVD	INC.	AZ.
(m)	(m)	(o)	(o)
0.00	0.00	0.00	0.00
188.00	188.00	0.25	0.00
409.00	409.00	1.00	0.00
603.00	603.00	0.50	0.00
795.00	795.00	1.00	0.00
998.00	998.00	0.25	0.00
1114.00	1114.00	0.75	0.00
1125.26	1125.21	0.96	179.86
1131.35	1131.30	0.98	183.15
1150.64	1150.58	1.14	99.29
1169.87	1169.81	2.46	65.94
1189.15	1189.05	4.56	67.49
1208.46	1208.27	6.22	84.21
1227.78	1227.46	7.18	89.57
1246.13	1245.64	8.43	86.73
1266.33	1265.61	9.08	75.21
1285.64	1284.65	10.09	62.20
1304.77	1303.45	11.04	60.74
1324.09	1322.39	11.85	62.84
1343.40	1341.23	13.56	68.21
1362.93	1360.14	15.34	72.37
1382.06	1378.52	16.79	72.83
1401.37	1396.93	18.35	72.57
1420.79	1415.26	20.27	75.72
1440.14	1433.40	20.40	76.89
1459.42	1451.38	21.98	79.06
1478.55	1469.01	23.73	81.56
1497.84	1486.56	25.26	80.88
1517.13	1503.90	26.74	77.82
1536.44	1521.04	28.10	74.23

DIRECTIONAL SURVEY			
MD	TVD	INC.	AZ.
(m)	(m)	(o)	(o)
1555.76	1538.06	28.42	69.84
1575.08	1555.08	28.03	65.30
1596.74	1574.18	28.31	60.13
1615.96	1591.02	29.34	54.51
1635.35	1607.82	30.61	48.36
1654.79	1624.46	31.67	42.46
1673.96	1640.74	32.17	38.85
1693.26	1657.04	32.59	35.57
1712.56	1673.40	31.48	39.44
1730.68	1688.75	32.73	36.50
1750.48	1705.23	34.54	33.94
1769.74	1721.03	35.33	29.94
1788.98	1736.70	35.57	25.45
1808.36	1752.42	36.08	21.46
1827.72	1768.06	36.15	15.39
1878.03	1808.84	35.65	7.45
1906.82	1831.59	39.95	2.77
1935.75	1853.73	40.19	0.54
1966.15	1876.26	44.13	0.92
1997.00	1897.66	48.00	1.89
2022.13	1913.77	52.25	2.68
2051.08	1930.41	57.51	3.42
2080.06	1945.04	61.86	5.22
2108.75	1957.44	66.89	5.56
2139.41	1968.23	71.90	5.73
2168.38	1975.87	77.51	5.20
2179.82	1978.27	78.29	5.04
2198.09	1981.73	79.85	5.03
2217.38	1984.97	80.79	4.77
2242.00	1988.66	82.00	4.50

5.4 CEMENTING OPERATIONS

CONDUCTOR-1

A 20” conductor pipe was cemented in place using Halliburton as a 3rd party cementer to a depth of 23.5mRT by spotting 3.5bbls of 15.8ppg cement slurry inside the 20” conductor from 23.5m – 20.0m and pumping 17bbls of 15.8ppg SwiftCem cement down the annulus through a cement stinger welded to the outside of the conductor pipe. All surface samples of cement cured as per program and Central Petroleum was satisfied with the integrity of the cement and conductor.

CONDUCTOR-2

The API 5CT, 13-3/8” 54.5ppf K-55 conductor #2 string was run to 249m RT and cemented to surface by pumping 122.1bbls of 12.5ppg Lead cement slurry and 41.8bbls of 15.8ppg Tail cement slurry. The cementing operations were performed by Halliburton as a 3rd party. The cement was displaced with 120.5bbls of displacement fluid with full cement returns to surface with no top up cement job required. The cement plug was bumped at 330psi and the casing was pressure tested to 1,500psi with floats holding post bleed down of pressure.

SURFACE CASING

The API 5CT, 9-5/8” 36/43.5ppf K-55/N-80 surface casing string was run to 1116.5m RT and cemented to surface by pumping 238bbls of 12.5ppg Lead cement slurry and 58bbls of 16ppg Tail cement slurry. The cement was displaced with 284bbls displacement fluid with full cement returns to surface. The cement plug was bumped at 1300psi and the casing was pressure tested to 2,700psi with floats holding post bleed down of pressure.

The integrity of the surface casing and cement was verified utilising various techniques and interpretations as follows: The review of the Halliburton post job report on the cementing/pumping operations demonstrated that the surface cement samples cured, and the cement was pumped per program, the casing cement plugs were bumped, and the casing pressure tested to 2,700 psi, verifying the integrity of the casing. A radial cement bond log (CBL) was run on 25 September 2018 and reviewed by independent experts. The findings for this section were that typically with cement bond logs, free pipe is in the order of 50mV (3-foot amplitude) while fully bonded casing would be +/ 1.5mV. The CBL for the Surface casing in PV13 shows that the majority of the well is below 20mV with the average (blue) trace in the 10mV range. The areas across porous sands show close to a perfect bond. It is common for the cement to set faster over porous intervals in the well due to water losses into these zones. There may be some free pipe over a 40m interval between 250m MD and 290m MD, however there is good cement bond above and below this interval.

Finally, after drilling out the shoe track, and conditioning the drilling fluid, a Formation Integrity Test (FIT) was performed to an equivalent mud weight of 14.2 ppg Estimated Mud Weight (EMW).

PRODUCTION LINER

The API 5CT,7" Liner 26ppf P-110 Liner was run to a depth of 1842 mRT and cemented back to the top of the Versaflex Liner Hanger Assembly located at 641.8 mRT. The Liner was cemented in place by pumping 92.8bbls of 13.5ppg Lead cement slurry followed by 37.6bbls of 15.8ppg Tail cement slurry. The cement was displaced with 167bbls displacement fluid. The cement plug was bumped and the Liner was pressure tested to 2,000psi with the floats holding post bleed down of casing pressure.

After releasing from the liner hanger, 30 bbls of excess cement was circulated out of the well ensuring full cement coverage from the shoe back to the liner hanger. The integrity of the Production Liner and cement was verified utilising various techniques and interpretations as follows: The review of the Halliburton post job report on the cementing/pumping operations demonstrated that the surface cement samples cured, and the cement was pumped as per program, the casing cement plugs were bumped as per program and the casing pressure tested to 1,820 psi on the Halliburton recorder (2,000 psi at the standpipe), verifying the integrity of the casing. The 7" liner hanger was run, set and pressure tested to 3,500 psi. Verifying the integrity of the liner hanger and the overlap from the 9 5/8" casing to the 7" liner. The cement bond log was run on 28 September 2018 and reviewed by independent experts and the findings for this section were: for the 7" casing, free pipe is in the order of 50mV (E1) while fully bonded casing would be +/- 1.5mV. Very good cement bond was seen over the Tail cement section from the casing shoe to the cement top of the tail located at 1500m which is distinctly seen on the CBL. When cementing the liner with a Versaflex Hanger Assembly it is a requirement and standard procedure to pump a Lead Cement heavily retarded to slow down the setting time of the cement in case of any issues with setting the Versaflex Hanger Assembly to provide a contingency. Having a heavily retarded cement requires a much longer curing/setting time. The CBL was performed approximately 70hrs after the cement job was completed, which was sufficient time for the tail cement to reach maximum strength. Though the CBL shows sporadic cement placement from 1,500m (Tail Top) – 641m (Hanger Assembly) within the Lead cement section; it is expected that further curing and strengthening time would have improved the CBL results within this section.

Finally, after drilling out the shoe track and 2m of new formation, a FIT was performed with 9.1ppg mud in the hole and a pressure of 871psi applied returning a 12.0 ppg EMW.

Table 4: Cementing details

CEMENTING DETAILS			
	Conductor-2	**Surface**	**Liner**
Hole Size	17-1/2”	12-1/4”	8-1/2”
Casing Size	13-3/8”	9-5/8”	7”
Setting Depth	248.9mRT (MD)	1116.5mRT (MD)	Top: 641.8mRT(MD) 641.8mRT(TVD) Shoe: 1842.0mRT(MD) 1779.6mRT(TVD)
Cement Type	Class G	Class G	Class G
Cement Top	Lead - Surface Tail – 200.0mRT	Lead - Surface Tail – 916.5mRT	Lead – 641.8mRT(MD) Tail – 1500.0mRT(MD) 1488.5mRT(TVD)
Yield	Lead - 2.155 ft^3/sk Tail – 1.165 ft^3/sk	Lead - 2.15 ft^3/sk Tail – 1.13 ft^3/sk	Lead – 1.71 ft^3/sk Tail – 1.163 ft^3/sk
Volume	Lead – 122.1bbls Tail – 41.5bbls	Lead – 238.0bbls Tail – 58.0bbls	Lead – 92.8bbls Tail – 37.6bbls
Slurry Density	Lead - 12.5 ppg Tail - 15.8 ppg	Lead - 12.5 ppg Tail – 16.0 ppg	Lead - 13.5 ppg Tail – 15.8 ppg
Bump Plug	330psi	1300psi	1320psi
Casing Pressure Test	1,500psi	2,700psi	1,820 & 6000psi
Additives	D-Air 3000L Calcium Chloride Bentonite	D-Air 3000L Calcium Chloride Bentonite Halad-344 CFR-3	D-Air 3000L Barite Barazan Halad-344 Halad-413 CFR-3 Tunes Spacer V

5.5 DRILLING FLUIDS

Table 5: PV13 Drilling fluids

DRILLING FLUIDS				
Interval	Hole Size	From	To	Fluid System
	[in]	[mRT]	[mRT]	
Conductor – 1	24	5.85	23.5	WBM - Gel Spud Mud
Conductor – 2	17-1/2	23.5	249.0	WBM – KCl / Polymer/Gel
Surface	12-1/4	249.0	1119.0	WBM – KCl / Polymer/Gel
Intermediate	8-1/2	1119.0(MD) 1119.0(MD)	1845.0(MD) 1782.0(TVD)	WBM – KCl / Polymer Air/Foam
Production	6-1/8	1845.0(MD) 1782.0(TVD)	2242.0(MD) 1988.7(TVD)	Air/Foam

5.6 FLUID LOSSES

No fluid losses were observed during the drilling operations of PV13.

6 FORMATION EVALUATION

6.1 WELL EVALUATION LOGS

No additional interpretations were completed on the logs in the table below

Table 6: Well evaluation logs

WELL EVALUATION LOGS		
Logging Suite	Top Logging Depth m MD	Bottom Logging Depth m MD
Mud logging (Total Gas and Gas Chromatograph)	0.00	2242.00
Cement bond log 9-5/8" csg	0.00	1124.31
Cement bond log 7" liner	542.96	1856.03
MWD – Gamma Ray	1842.00	2242.00
MWD - Temperature	1842.00	2242.00
MWD – Rate of Penetration	1842.00	2242.00

6.2 CORES AND SAMPLE DETAILS

No cores were cut in PV13. Cuttings samples were collected as follows:

Surface to 1120m MD 15m interval

1120m to 2242m MD 5m interval

12 gas samples were retrieved in Isotubes from the mud gas line while drilling with air/foam in the Lower Stairway Sandstone to Pacoota P1 Sandstone. Please see gas sample analysis in appendix B

All the samples except for the last two samples (2011mMD and 2022m MD) were severely contaminated with air from the air drilling operations. The last two samples had contained +80% hydrocarbons with residual nitrogen and oxygen.

Table 7: PV13 Gas samples

GAS SAMPLES		
Depth (m MD)	Formation	Notes
1739	Lower Stairway Sandstone	High air contamination, not representative of reservoir
1742	Lower Stairway Sandstone	High air contamination, not representative of reservoir
1814	Horn Valley Siltstone	High air contamination, not representative of reservoir
1820	Horn Valley Siltstone	High air contamination, not representative of reservoir
1823	Horn Valley Siltstone	High air contamination, not representative of reservoir
1899	Pacoota P1 Sandstone	High air contamination, not representative of reservoir
1900	Pacoota P1 Sandstone	High air contamination, not representative of reservoir
1903	Pacoota P1 Sandstone	High air contamination, not representative of reservoir
1919	Pacoota P1 Sandstone	High air contamination, not representative of reservoir
1961	Pacoota P1 Sandstone	High air contamination, not representative of reservoir
2011	Pacoota P1 Sandstone	73.8% - C1, 6.3% - C2, 4.1% - O_2, 14.4% - N_2
2022	Pacoota P1 Sandstone	79.5% - C1, 6.8% - C2, 2.6% - O_2, 9.5% - N_2

7 GEOLOGY

7.1 LITHOLOGY AND STRATIGRAPHY

Table 8: PV13 well tops

Well tops				
Age	**Formation Name**	**Actual Depth m MD**	**Actual Depth m TVD**	**Actual Thickness TVT (m)**
Late Devonian	Hermannsburg Sst	5.85	5.85	383.15
Middle Devonian	Parke Siltstone	389.00	389.00	34.00
Late Silurian to Middle Devonian	Mereenie Sandstone	423.00	423.00	575.00
Middle to Late Ordovician	Carmichael Sst	998.00	998.00	84.00
Middle Ordovician	Stokes Siltstone	1082.00	1082.00	325.00
Middle Ordovician	Upper Stairway Sst	1412.00	1407.00	23.90
Middle Ordovician	Middle Stairway Sst	1437.00	1430.90	153.20
Middle Ordovician	Lower Stairway Sst	1608.00	1584.10	130.60
Middle Ordovician	Horn Valley Siltstone	1761.00	1714.70	82.60
Early Ordovician	Pacoota P1 Sst	1864.00	1797.30	191.40
	TOTAL DEPTH	2242.00	1988.70	

The lithology and stratigraphy is well understood at the Palm Valley Field due to the previous 11 wells drilled on the structure.

Hermannsburg Sandstone (5.85m to 389.00m MD)

The Hermannsburg Sandstone consists of sandstone interbedded with siltstone and shale and was deposited in a non-marine fluvial and alluvial fan environment.

Parke Siltstone (389.00m to 423.00m MD)

The Parke Siltstone consists of siltstone and shale with minor sandstone and trace gypsum/anhydrite and was deposited in a lacustrine environment.

Mereenie Sandstone (423.00m to 998.00m MD)

The formation consists of a massive sandstone sequence that was deposited in a shallow marine and aeolian environment. The Mereenie Sandstone is a permeable groundwater aquifer in this area.

Stokes Siltstone (1082.00m to 1412.00m MD)

The Stokes Siltstone consists of a massive siltstone sequence, interbedded with minor sandstones. The formation was deposited in a predominantly shallow marine environment. The Stokes Siltstone forms the seal for the hydrocarbon accumulations at Mereenie.

Upper Stairway Sandstone (1412.00m to 1437.00m MD)

The Upper Stairway Sandstone is a dominantly sandstone unit with interbed siltstones and was deposited in a predominantly tidally influenced marine environment.

Middle Stairway Sandstone (1437.00m to 1608.00m MD)

The Middle Stairway Sandstone is a dominantly siltstone unit with interbedded sandstones and was deposited in a shallow marine environment.

Lower Stairway Sandstone (1608.00m to 1761.00m MD)

The Lower Stairway Sandstone is a dominantly sandstone unit with interbed siltstones and was deposited in a predominantly tidally influenced marine environment.

Horn Valley Siltstone (1761.00m to 1864.00m MD)

The Horn Valley Siltstone is an interbedded unit of siltstone, shale, limestone/dolomite and minor sandstone which was deposited in shallow to deep marine environment.

Pacoota P1 Sandstone (1864.00m to 2242.00m MD)

The Pacoota P1 Sandstone is a variably interbedded sequence of sandstone, siltstone and minor shale which was deposited in an intertidal to shallow marine environment.

7.2 STRATIGRAPHIC PROGNOSIS

Formation tops were intersected higher to prognosis, with increasing diversion between prognosed and actual figures with depth. The target Lower Stairway Sandstone, Horn Valley Siltstone and Pacoota P1 Sandstone were intersected 16.9 m, 24.3 m and 21.7 m high to prognosis respectively.

The prognosed depths were determined from a 3D geologic model that was generated from the depth converted seismic interpretation and tied to formation tops of existing wells. This geological model building process will honour the known depth points at existing wells, however, the model geometry between the existing wells, controlled by the depth converted seismic interpretation, is modified when tied to the existing well tops. As a result of the modification to the model geometry, prognosed formation tops for proposed wells away from existing wells and seismic have a higher degree of uncertainty and are therefore subject to error.

The fact that the actual depths are high to the prognosed formation depths suggest that the model geometry has been pulled down in the vicinity of PV13 when tied to the existing wells. The prognosed and actual depths are listed in Table 9. The revised structure map and seismic section are shown in Appendix D.

Table 9: PV13 well prognosed vs actual tops

Well Tops				
Formation Name	**Prog Depth m TVD**	**Actual Depth m TVD**	**Actual Depth m SS**	**High/Low To Prognosis**
Hermannsburg Sst	5.85	5.85	-843.04	Nil
Parke Siltstone	399	389.00	-459.89	10.0m H
Mereenie Sst	435	423.00	-425.89	12.0m H
Carmichael Sst	1017	998.00	149.11	19.0m H
Stokes Siltstone	1103	1082.00	233.11	21.0m H
Upper Stairway Sst	1409	1407.00	558.11	2.0m H
Middle Stairway Sst	1449	1430.90	582.01	18.1m H
Lower Stairway Sst	1601	1584.10	735.21	16.9m H
Horn Valley Siltstone	1739	1714.70	865.81	24.3m H
Pacoota P1 Sst	1819	1797.30	948.41	21.7m H
TOTAL DEPTH	2102	1988.70	1139.81	113.3m H

7.3 RESERVOIR PROPERTIES AND QUALITY

Lower Stairway Sandstone

	Latitude (GDA 94)	**Longitude (GDA 94)**	**Easting (Zone 53)**	**Northing (Zone 53)**
Lower Stairway Reservoir intersection in PV13	23° 59' 34.2514" S	132° 43' 38.1879"	268785 m	7344700 m

The Lower Stairway Sandstone was intersected 16.9m higher than prognosis and upon drilling with air, limited mud gas readings of ~0.1% were observed from the fluid returns. Minor connection and trip gas were observed while drilling and for bit changes. A flow test of the zone was not completed in this well due to the low mud gas readings. However, other wells within the Palm Valley Field have produced gas from the Lower Stairway Sandstone (PV1, PV2, PV6b, PV7) via the natural fracture network. The prospectivity of the Lower Stairway Sandstone is encouraging throughout the field, however at the PV13 location, natural fracture development and/or interconnectedness has not been observed.

Horn Valley Siltstone

	Latitude (GDA 94)	**Longitude (GDA 94)**	**Easting (Zone 53)**	**Northing (Zone 53)**
Horn Valley Siltstone Reservoir intersection in PV13	23° 59' 32.0373" S	132° 43' 40.1016" E	268838	7344769

The Horn Valley Siltstone was intersected 24.3m higher than prognosis and upon drilling with air, increasing mud gas readings were observed. Minor connection and trip gas were observed while drilling and for bit changes. A flow test of the zone was completed with a 0.02MMscf/d stabilized rate recorded. However, other wells within the Palm Valley Field have produced gas from the Horn Valley Siltstone (PV1, PV2, PV7) via the natural fracture network. The prospectivity of the Horn Valley Siltstone is encouraging throughout the field, however at the PV13 location, natural fracture development and/or interconnectedness has not been observed.

Pacoota P1 Sandstone

	Latitude (GDA 94)	**Longitude (GDA 94)**	**Easting (Zone 53)**	**Northing (Zone 53)**
Pacoota P1 Reservoir intersection in PV13	23° 59' 30.2907" S	132° 43' 40.6629" E	268853	7344823

Pacoota P1 Sandstone was intersected 21.7m higher than prognosis and upon drilling with air, increasing mud gas readings were observed. Minor connection and trip gas were observed while drilling and for bit changes. An increase in mud gas rate at 1890m to 1946m MD necessitated a flow test which recorded a rate of 0.56MMscf/d. Drilling with air foam continued until a noticeable increase in the size of the flare occurred at 2011m MD with a flow test recording 4.6MMscf/d. Further drilling with air/foam resulted in another increase in visual size of the flare at 2022m MD with multiple flow tests over this interval confirming a rate between 10.7 and 13.6MMscf/d. Drilling progressed to TD of 2242m MD without much change in flowing rates. The completion was run and the well suspended as a future producer from the Lower Stairway, Horn Valley and Pacoota P1 formations.

7.4 GEOCHEMISTRY OF SOURCE ROCKS

No geochemistry samples were taken

7.5 HYDROCARBON INDICATORS

PV13 targeted areas of modelled high natural fracture densities within the Lower Stairway and Pacoota P1 Sandstones. Gas was first observed at 1455m MD on the mud log in the Middle Stairway Sandstone. An increase in mud gas within the Lower Stairway Sandstone necessitated a flow test, the flow rate was 0.02MMscf/d. Upon further drilling into the Pacoota P1 Sandstone, gas rates of 10.7-13.6MMscf/d were recorded during open hole flow tests. The PV13 well was completed with a packer and 3-1/2' tubing and suspended until surface facility works can be completed.

Six production tests were carried out on PV13 while drilling with air/mist, see Table 10. The first flow test was carried out at the 8-1/2" TD section before the 7" liner was run. The flow test was from an open hole interval of 1116.5m to 1845.0m MD and the stabilized rate was 0.017MMscf/d for 60 minutes through a 2" choke. A second flow test was conducted from 1842.0 to 1946.0m MD with a stabilized rate of 0.56MMscf/d for 32 minutes through a 2" choke. Due to an increase in mud gas, a third flow test was conducted from 1845.0 to 2011m MD with a stabilized rate of 13.6MMscf/d for 14 minutes through a 3-1/2" choke. During a bit trip, a flow and build-up at different back pressures was undertaken from 1842.0 to 2022.0m MD. A final flow test was conducted at 1842.0m to 2122m MD with a stabilized rate of 12.1MMscf/d for 15 minutes on a 3-1/4" choke.

Table 10: PV13 production flow tests

Production Flow Tests					
Test number and Formation	**Test Interval (m MD)**	**Gas Rate (MMscf/d)**	**Pressure (psi)**	**Duration (minutes)**	**Orifice size (inch)**
1 (Lower Stairway - HVS)	1116.5 - 1845.0	0.02	1.2	60	2"
2 (HVS - Pacoota P1)	1842.0 - 1946.0	0.56	15.0	32	2"
3 (HVS - Pacoota P1)	1842.0 - 2011.1	4.60	44.0	38	2"
4 (HVS - Pacoota P1)	1842.0 - 2020.0	13.60	29.0	6	3"
5 (HVS - Pacoota P1)	1842.0 - 2022.0	12.00	29.0	15	3.5"
5 (HVS - Pacoota P1)	1842.0 - 2022.0	11.90	95.0	30	3.5"

5 (HVS - Pacoota P1)	1842.0 - 2022.0	11.00	175.0	30	3.5"
5 (HVS - Pacoota P1)	1842.0 - 2022.0	10.70	220.0	30	3.5"
6 (HVS - Pacoota P1)	1842.0 - 2122.0	12.10	34.0	15	3.25"

8 CHANGES TO THE RESERVOIR MODEL AND IMPLICATIONS FOR FUTURE FIELD MANAGEMENT

8.1 CHANGES TO THE RESERVOIR MODEL FOLLOWING THE DRILLING OF PALM VALLEY 13

PV13 was drilled to specifically appraise the productivity of areas of high fracture density in the Stairway Sandstone, Horn Valley Siltstone and Pacoota P1 Sandstone at the Palm Valley field. Previous drilling in the Palm Valley Field identified hydrocarbon productivity related to natural fractures. The drilling of PV13 was to appraise the connectivity of the field and intersect areas of high-density natural fractures that were not connected to the producing wells. PV13 intersected natural fractures that flowed on production test at >12MMscfd and the pressure build-up after the production tests showed that the current reservoir pressure at PV13 was ~1,000 psi, which is inline with the rest of the field. This suggests that PV13 has not accessed unconnected reservoir and could be an acceleration well as opposed to adding additional reserves for the Palm Valley Field. The PV13 well tops have been incorporated into the geologic model which shows a subtle change to the structure around PV13.

8.2 IMPLICATIONS FOR FUTURE FIELD MANAGEMENT

The PV13 well was a technically challenging well due to the requirement to drill the reservoir section without mud and allow for the well to be completed without fluid. From this success, Central has gained the knowledge to drill highly deviated wells within the Palm Valley Field without damaging the formation with fluid. PV13 did flow at commercial gas rates and with further production and pressure monitoring from adjacent wells, analysis on how connected the wells are within the field can be conducted. Additional wells may be planned in the future and will also target areas of high fracture density. Due to the challenging terrain, any future well surface location will likely be positioned near existing wells.

Please see the following appendices:

Appendix C for the Palm Valley 13 Composite Well Log

Appendix D for the revised structure maps and seismic sections