ELCANO EXPLORATION INC.
1600, 521 – 3rd Avenue SW Calgary, Alberta T2P T3T Tel: (403) 460 - 4188 Fax: (403) 460 - 4965

Proposed Miniota Unit No. 1

Application for Waterflood

Miniota, Manitoba

June 25, 2019

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Introduction

In accordance to Section 71 of the Drilling and Production Regulations of Manitoba, Elcano Exploration Inc. is requesting the Regulatory Authority's approval of the proposed Miniota Unit No. 1 and waterflood project.

The discovery well was drilled during December 2013, since then a total of seven additional wells have been drilled into the proposed unit area targeting Amaranth reservoir. A low recovery under primary production is expected due to the absence of pressure support through either a natural water or gas drive to supply energy to the reservoir. The shallow depth of the reservoir translates into a low initial pressure. The shallow reservoir depth and the absence of natural pressure support will result in a low recovery of the original oil in place during primary recovery.

Results from an offsetting analogous reservoir under waterflood demonstrates that oil recovery can be greatly improved with supplemental pressure support through water injection. Following approval of the proposed unit and waterflood, one existing well will be converted to a water injector in to initiate the waterflood.

If you have any questions or concerns about the application, please contact the undersigned.

Sincerely,

[redacted]

Greg [redacted], P.Geo.
VP Exploration

Elcano Exploration Inc.
[redacted]
Calgary, Alberta
[redacted]

(403) 919-9592
gjones@elcano.ca

Summary

1. The proposed unit will included 24 legal subdivisions (LSD's) across sections 01-013-27W1 (16 LSD's) and the west half of 06-013-26W1 (8 LSD's). To date, eight wells are completed in the Amaranth formation (*Appendix A, Figure 1)*.

2. Original oil in place for the proposed unit is calculated at 597 e^3m^3 (*Appendix C, Figure 1*).

3. During March 2019, the producing wells within proposed unit averaged an oil rate 9.0 m^3/d with an associated water cut of 91.8% (*Appendix C, Figure 2)*.

4. Cumulative oil production as of April 1, 2019 is 50.1 e^3m^3, calculating a recovery factor of 8.3% within the proposed unit boundary (*Appendix C, Figure 3)*.

5. Decline analysis for the productive wells shows anultimate recovery of 62.3 e^3m^3 and calculates a recovery factor of 10.4% under primary depletion. As of April 1, 2019, the remaining recoverable oil in place is 12.2 e^3m^3.

6. Initial pressure of the Amaranth reservoir is estimated to be 5,500 kPa. Current reservoir pressure is determined to be approximately 1227 kPa from an acoustic fluid level measurement performed on June 15, 2019 on the (03-01) 100/03-02-013-27W1 well (re-completed across Amaranth).

7. The North Scallion Unit No. 1 waterflood in section 04-012-26W1 (located 9 km south east) is an analogue with similar geology and reservoir characteristics, where the recovery factor under waterflood has reached 35%. Improved recovery can be achieved from the Amaranth formation through the implementation of a waterflood. The ultimate recovery from the waterflood for the proposed Miniota Unit No. 1 is estimated to be 125 e^3m^3, giving a secondary recovery factor of 20.9% (*Appendix C, Figures 4 and 5)*.

Geological Discussion

Stratigraphy

The Amaranth is a carbonate interval and can be identified on the type log 100/05-06-013-26W1 from 535.4 to 543.0 m MD (*Appendix B, Figure 1)*. The Amaranth carbonate overlays Amaranth anhydrite that in turn overlay Flossie Lake carbonates. The Amaranth carbonate is capped with the Melita and/or Reston shale. To the west, the Amaranth carbonate and anhydrite intervals terminate against a structurally high Lodgepole ridge of the North Hargrave pool.

Sedimentology

At the base of the Amaranth carbonate interval, a dark grey fissile shale is present that overlays the anhydrites below. The main reservoir facies is composed of a basal anhydrite dolostone layer that grades upward into a thicker sandy and silty dolomite/limestone interval with thin interbeds of carbonaceous shale-siltstone and a tighter upper limestone. Porosity in the dolostone is composed of pin point to fingernail size vugs that are commonly horizontally laminated and have porosities greater than 18%. Reduced porosity at pool edges likely results from inferior development of vugs and/or reduced permeability from anhydrite, silts and shales. The reservoir unit is capped by a tighter darker fissile unit composed primary of carbonaceous/dolomitic shale and siltstone.

Structure

There is 3D seismic coverage over the greater Two Creeks-Miniota-Hargrave area. The seismic shows a significant thickening of the overall Lodgepole within the proposed unit, resulting in an Amaranth structural ridge with structural drape evident above and to the second white specks. The thick Lodgepole wedge coincides with dissolution of Devonian age Prairie Evaporites. Late structure likely resulted in fracturing and interconnection of the reservoir. The Amaranth structure rises northward on a structural ridge and plunges steeply to the east. Structure at the Amaranth carbonate top varies between -76m and -58m in the proposed unit. The 14-36-012-27W1 well on the SW edge of the pool is interpreted to be wet with an oil/water contact at approximately -75m. Structurally higher wells along the eastern and northern edge of the pool (14-31-012-26W1, 02-07-013-26W1 and 06-12-013-27W1) that tested only water were interpreted to have isolated porosity or locally higher oil/water contacts *(Appendix B, Figure 2)*.

Reservoir

Amaranth reservoir quality is generally better where the carbonate dolostone porosity and permeabilities are enhanced with vugs. The core analysis table *(Appendix B, Figure 5)* illustrates the range of parameters with porosities exceeding 10% highlighted in six pool wells. Dolostone pay intervals in these wells have micro and intercrystalline matrix porosity with pin point to finger nail size vugs and are commonly laminated and often brecciated. Some core intervals with abundant vugs and breccia became rubbled and analysis was not possible. Core analysis show porosities in the 'teens' with some streaks in the low twenties. Kmax varies from mD's to Darcys. The cumulative production (April 1st, 2019) of 42.6 e^3m^3 from three pool wells (05-06-013-26W1, 04-01 and 07-01-013-27W1) attests to excellent reservoir quality in the pool. Up-dip trapping was provided by anhydrite, chert and poorly scattered porosity. Wells periphery to the pool were tight without oil shows or tested very high water cuts from structurally low or discontinuous porosity.

Open-hole logs, core analysis, strip-logs, swab tests and production tests were used to assign net pay values. Due to the laminated nature of the reservoir porosity the high resolution density log was very useful in defining reservoir. The thin bed effects on resistivity made log oil saturation calculations difficult however, using thicker porosity intervals, an average water saturation of 38% was calculated. Oil shows in cores, chip samples and during production tests were used to confirm pay. A porosity cutoff of 6% on the Limestone density scale generally corresponded to an Amaranth core porosity above 10% and was used to define pay, further supported by oil shows (*Appendix B, Figures 3 and 5).*

Reservoir Characteristics and Current Recovery

Original Oil in Place

As previously noted, porosity and water saturation values were determined from a number of independent sources including neutron-density logs and core analysis from wells drilled into the proposed unit area. This petrophysical data is available upon request. This data supported the volumetric calculation of the original oil in place over the proposed unit area that was determined to be equal to 597 e^3m^3. The original oil in place per LSD analysis can be seen in *Appendix C, Figure 1*.

Reservoir and Fluid Properties

The Reservoir and fluid properties for the Amaranth formation are outlined in the tables below. Additional information supporting the following values can be submitted upon request.

Reservoir Properties

Entity	Value	Source
Initial Reservoir Pressure	5.5 MPa	Wellbore fluid levels of initial completions
Reservoir Pressure 11/14/16	1.1 MPa	100/01-01-013-27W1 Gradient
Reservoir Pressure 07/13/18	0.6 MPa	(03-01) 100/03-02-013-27W1 Gradient
Reservoir Temperature 07/13/18	28.5 °C	(03-01) 100/03-02-013-27W1 Gradient
Formation Breakdown Pressure	12.3 MPa	12-01-013-27W1 Treatment - 08/08/14
Average Porosity	16.67%	Area Wells - Cores/Logs
Average Water Saturation	38.00%	Area Wells - Cores/Logs

Fluid Properties

Entity	Value	Source
Oil Gravity API @ 15 °C	28.5	100/07-01-013-27W1 - Oil Analysis
Oil Sulphur Content	1.71%	100/07-01-013-27W1 - Oil Analysis
Oil Dynamic Viscosity @ 20 °C	18.55 cP	100/07-01-013-27W1 - Oil Analysis
Formation Water Salinity	28,000 ppm	100/07-01-013-27W1 - Water Analysis
Formation Water Resistivity @ 19 °C	0.202 Ω*m	100/07-01-013-27W1 - Water Analysis

Historical Production

The proposed unit is currently developed with vertical wells on a 64 Ha spacing. As of April 1st, 2019, 50.1 e^3m^3 of oil has been recovered. Historical production peaked during April 2015 at 85.4 m^3/d of oil and 155.2 m^3/d water (*Appendix C, Figure 2)*.

Primary Depletion

Estimated primary ultimate oil recovery from the proposed unit is 69.3 e^3m^3 using decline analysis on individual wells and a 0.32 m^3/d per well economic cut-off.

Over the last 24 months, the pool has experienced an annual decline rate of 20%. A group plot of declines for the proposed unit wells can be seen in *Appendix C, Figure 2*.

Surface gas to oil ratio is less than 5 m^3/m^3. To date, no formal PVT analysis has been performed, however, the reservoir is likely now operating below the bubble point pressure. With very little solution gas present, virtually no aquifer pressure support and the shallow formation depth, the primary reservoir drive recovery mechanism is extremely limited. A waterflood will provide the necessary energy to the reservoir to increase the oil recovery.

Unitization

Unit name: Elcano Exploration Inc. proposes that the name of the new unit will be Miniota Unit No.1.

Unit Operator: Elcano Exploration Inc. will assume operatorship of the proposed Miniota Unit No.1.

Unitized Zone: The proposed unitized zone will be the Amaranth formation.

Unit Lands: Section 01-013-27W1 and the west half of section 06-013-26W1 will be included in the proposed Miniota Unit No.1.

Unitized Wells: Miniota Unit No.1 will consist of one injector well, one monitor well and six producer wells. The proposed injection well (03-01) 100/03-02-013-27W1 will be immediately converted upon approval of the unit and according to the proposed development plan outlined in *Appendix D, Figure 3*.

Following table lists existing wells within the proposed unit area:

License #	UWI	Proposed Status
9448	100/01-01-013-27W1 VT	Monitor
10389	(03-01) 100/03-02-013-27W1 HZ	Injector (conversion)
9846	100/04-01-013-27W1 VT	Producer
9649	100/07-01-013-27W1 VT	Producer
9990	100/12-01-013-27W1 VT	Producer
10079	100/16-01-013-27W1 VT	Producer
10078	100/05-06-013-26W1 VT	Producer
10229	100/13-06-013-26W1 VT	Producer

Working interest and mineral owners: Elcano Exploration Inc. is currently the 100% working interest holder in the proposed Miniota Unit No. 1.

Tract Factors: Tract factors will be determined as a factor of remaining oil in place per LSD.

Mineral lessors and tract calculations are summarized in *Appendix A, Figure 3*.

Waterflood Project Development

Proposed Water Injection Well Conversions and Timing

Elcano proposes to convert one well to an injector and commence injection upon the Regulatory Authority's approval. A typical injector well schematic can be seen in *Appendix D, Figure 1*.

Total daily injection for the proposed unit is expected to be approximately 750 m^3/d. Source water for injection will be produced water derived from Elcano's owned and operated (100% WI) North Hargrave battery at 03-34-012-27W1.

Injection water will be treated and filtered at the 03-34-012-27W1 battery, then pumped through an injection line to the proposed injection well. Composite reinforced pipe will be utilized for the injection line. A flow diagram of the proposed injection system can be seen in *Appendix D, Figure 2.* Corrosion mitigation measures will also be employed throughout the duration of the proposed waterflood and are outlined in *Appendix D, figure 4.*

Injection Well and Rate

License #	UWI	Conversion Timing	Injection Rate
10389	(03-01) 100/03-02-013-27W1 HZ	Upon Approval	750 m3/d

The initial injection rate is based on an injectivity test performed during the re-completion of the Amaranth interval in the (03-01) 100/03-02-013-27W1 HZ well.

Injection Well Maximum Wellhead Pressure

Entity	Value
Formation Fracture Gradient	22.4 kPa/m
(03-01) 100/03-02-013-27W1 HZ Amaranth mid-point perforation	548.6 m TVD
Bottom-hole Formation Fracture Pressure	12.3 MPa
Injection Water Density at 25 °C	1025 kg/m3
Hydrostatic Column Pressure at mid-point perforations	5.5 MPa
Formation Fracture Pressure at Wellhead Pressure	6.8 MPa
90% of Formation Fracture Pressure at Wellhead Pressure	6.1 MPa

Formation fracture gradient was derived from hydraulic fracture data from the offset 12-01-013-27W1 well during a fracture stimulation performed on September 8th, 2014. This data determined the fracture gradient to be 22.4 kPa/m and calculates a formation fracture pressure of 12,229 kPa measured at the mid-point perforations of 548.6 m TVD for the Amaranth in the (03-01) 100/03-02-013-27W1 well. The bottom-hole pressure generated by the static column of produced (injection) water in that wellbore is 5,516 kPa. Formation fracture pressure at the wellhead calculates to be 6,772 kPa at static conditions. Elcano requests the maximum wellhead injection pressure to be 90% of the formation fracture at the wellhead. This calculates to be 6,095 kPa.

Waterflood Operating Strategy

The first injector conversion is proposed to occur upon approval of the application. It is expected to take approximately 12 months to replace the current voidage volume. Once the reservoir fill up is reached, a voidage replacement ratio of 1.0 will be maintained.

The following surveillance data and calculations will be acquired throughout the duration of the waterflood:

1. Waterflood pressure response will be monitored in the 01-01-013-27W1 well
2. Wellhead test meters will be used on all wells to acquire daily rates
3. Continuous wellhead injection pressure monitoring
4. Wellhead water cuts taken weekly on all producing wells
5. Selected use of chemical tracers to track water injector/producer responses
6. The use of some or all of conformance plots, water oil ratio trends, log water oil ration versus cumulative oil, hydrocarbon pore volume injected, reservoir pressure trends, Hall plots, fractional low curves, etc.
7. Analysis of acquired data and observation of trends in water oil ratio, reservoir pressure, production rate, injection rate, cumulative production, etc.

The above surveillance methods will allow a full understanding of reservoir performance and provide data to continually optimize the waterflood. Proper monitoring will provide early indicators of any issues and allow for adjustment to the operation to maximize oil recovery.

In accordance to Section 73 of the Drilling and Production Regulations, an annual EOR report outlining the above data and calculations will be submitted within 60 days of initial injection and within 60 days after the end of each calendar year.

Technical Studies

The performance predictions for the proposed waterflood are based on geological and engineering analysis. Extensive analysis of open-hole logs; core data; petrophysics; seismic; drilling information; completion information; and production information were used to develop geological maps and establish reservoir parameters to support original oil in place calculations.

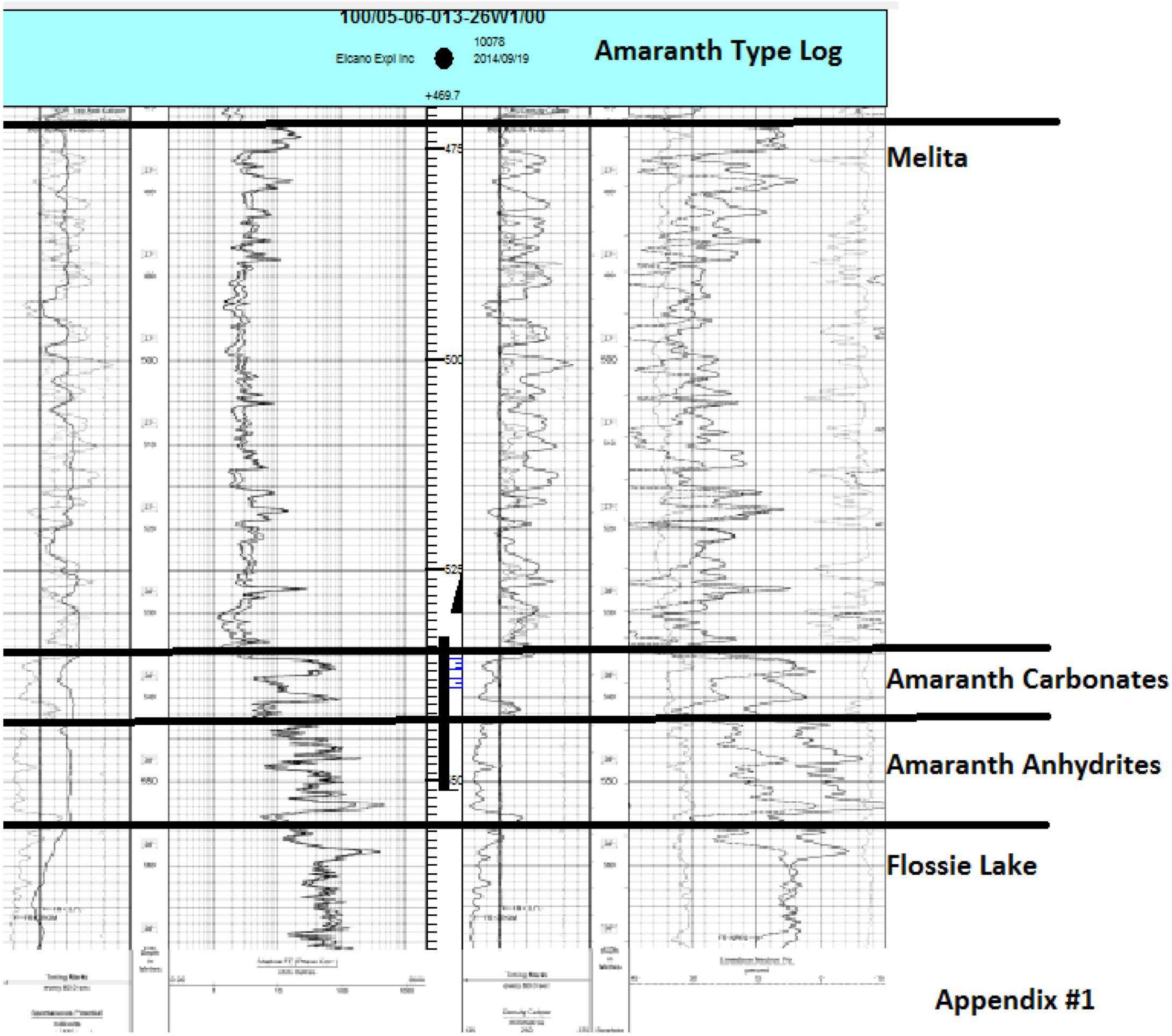
Although there is not a direct waterflood analog to the Amaranth reservoir, the North Scallion Unit No. 1 waterflood in section 04-012-26W1 (located 9 km south east) is comparable with similar geology and reservoir characteristics. To date, the secondary recovery factor for this analog pool is calculated at 35%.

Secondary Recovery and Production Forecast

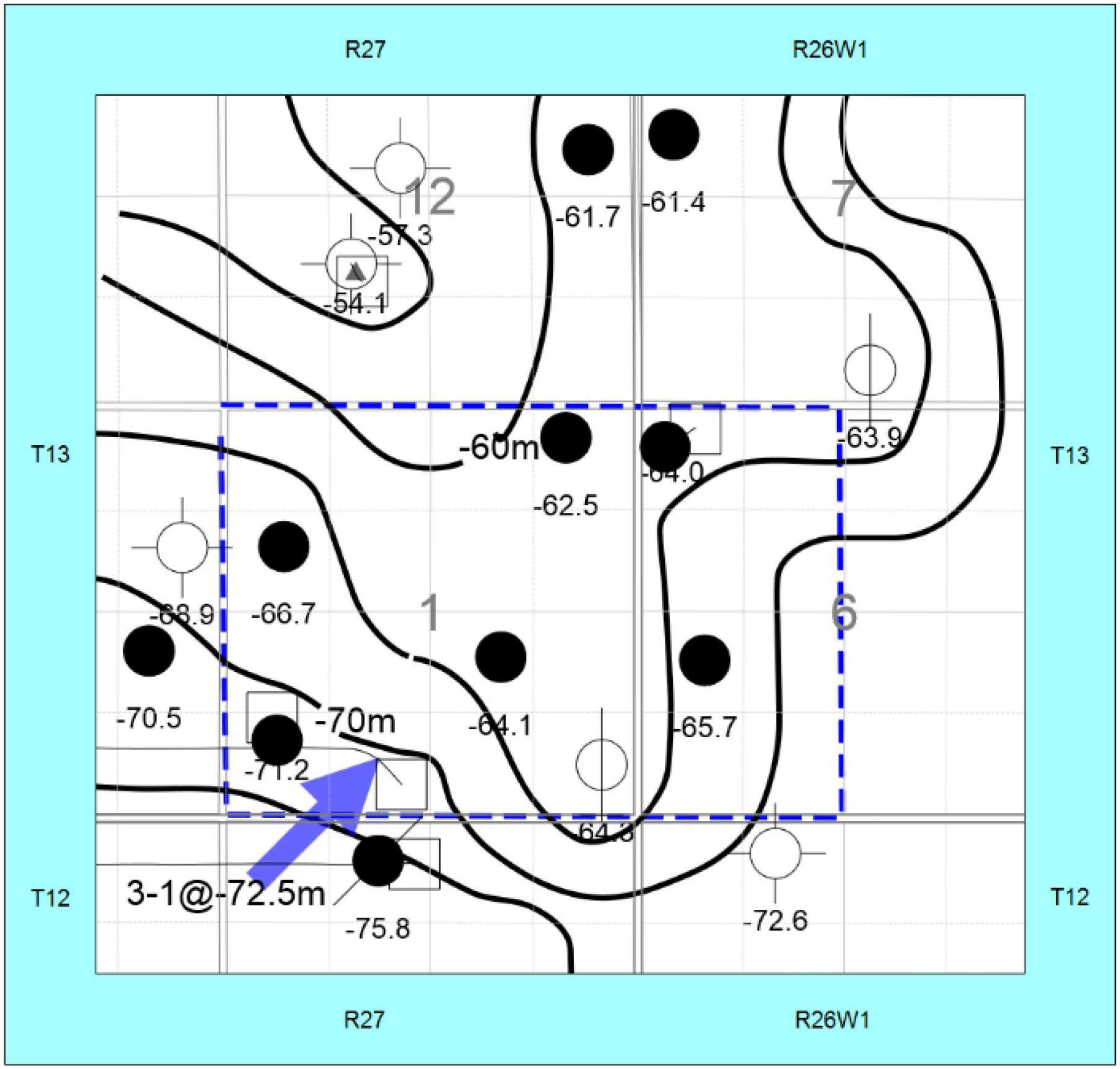
The estimated ultimate recovery over the proposed waterflood area is based on forecasts from the individual well declines under pressure support. An economic cut-off of 0.32 m^3/d of oil was used in the waterflood scenario as fixed injection well costs were allocated to the remaining producers. The resultant estimated ultimate recovery for the waterflood is 125 e^3m^3, this yields an ultimate waterflood recovery factor of 20.9%, an incremental 63.7 e^3m^3 of oil. Forecasted production profiles for both primary and waterflood can be seen in *Appendix C, Figure 4*.

Appendix B: Geological Maps

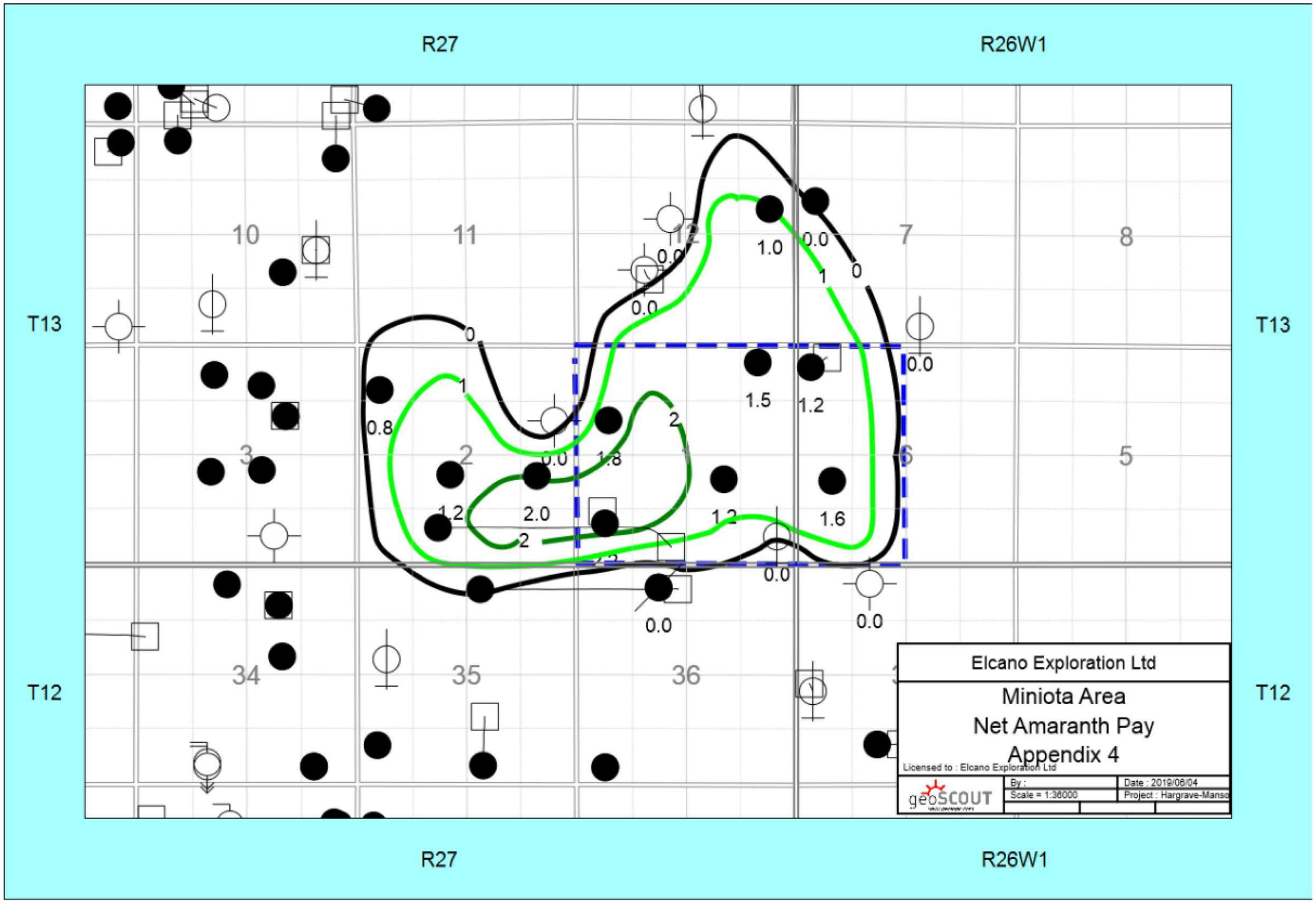
Appendix B, Figure 1: Amaranth Type Log



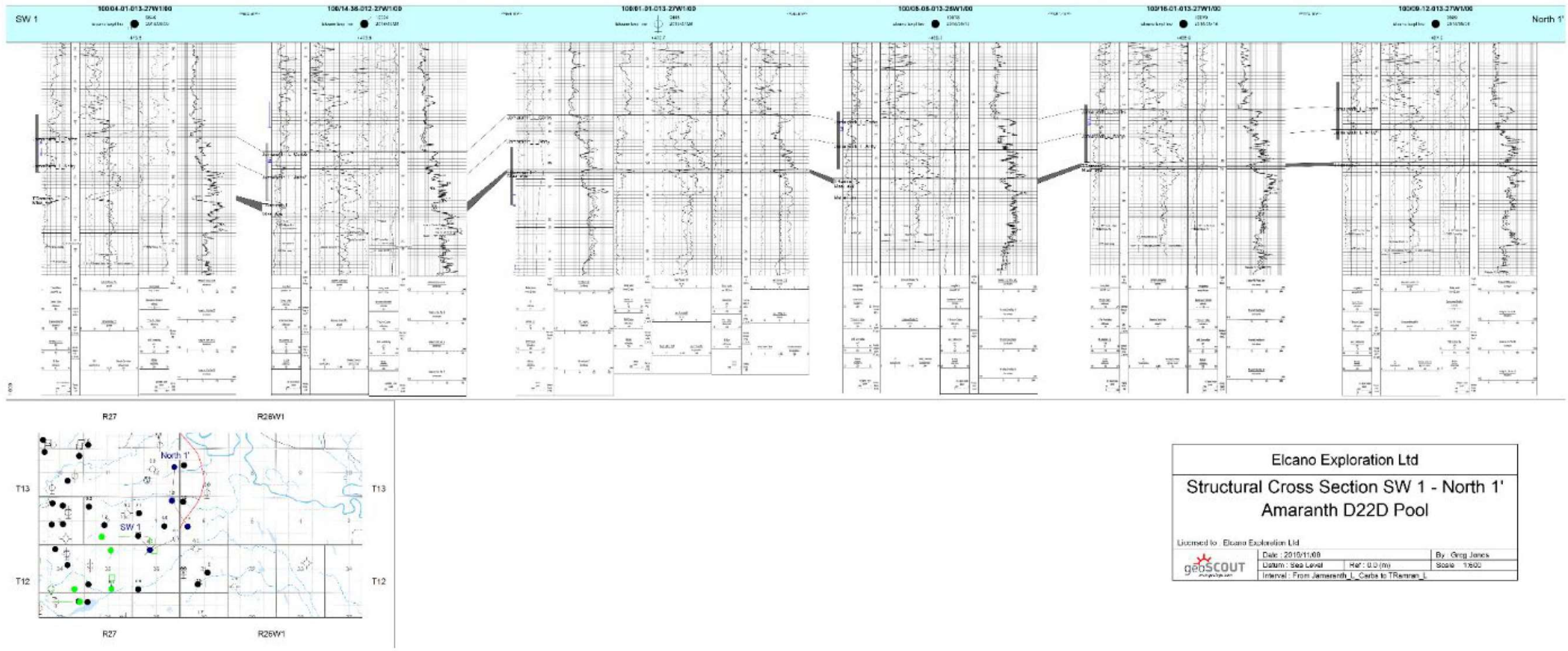
Appendix B, Figure 2: Amaranth Structure



Appendix B, Figure 3: Amaranth Pay



Appendix B, Figure 4: Amaranth Cross Section



Appendix B, Figure 5: Amaranth Core Table

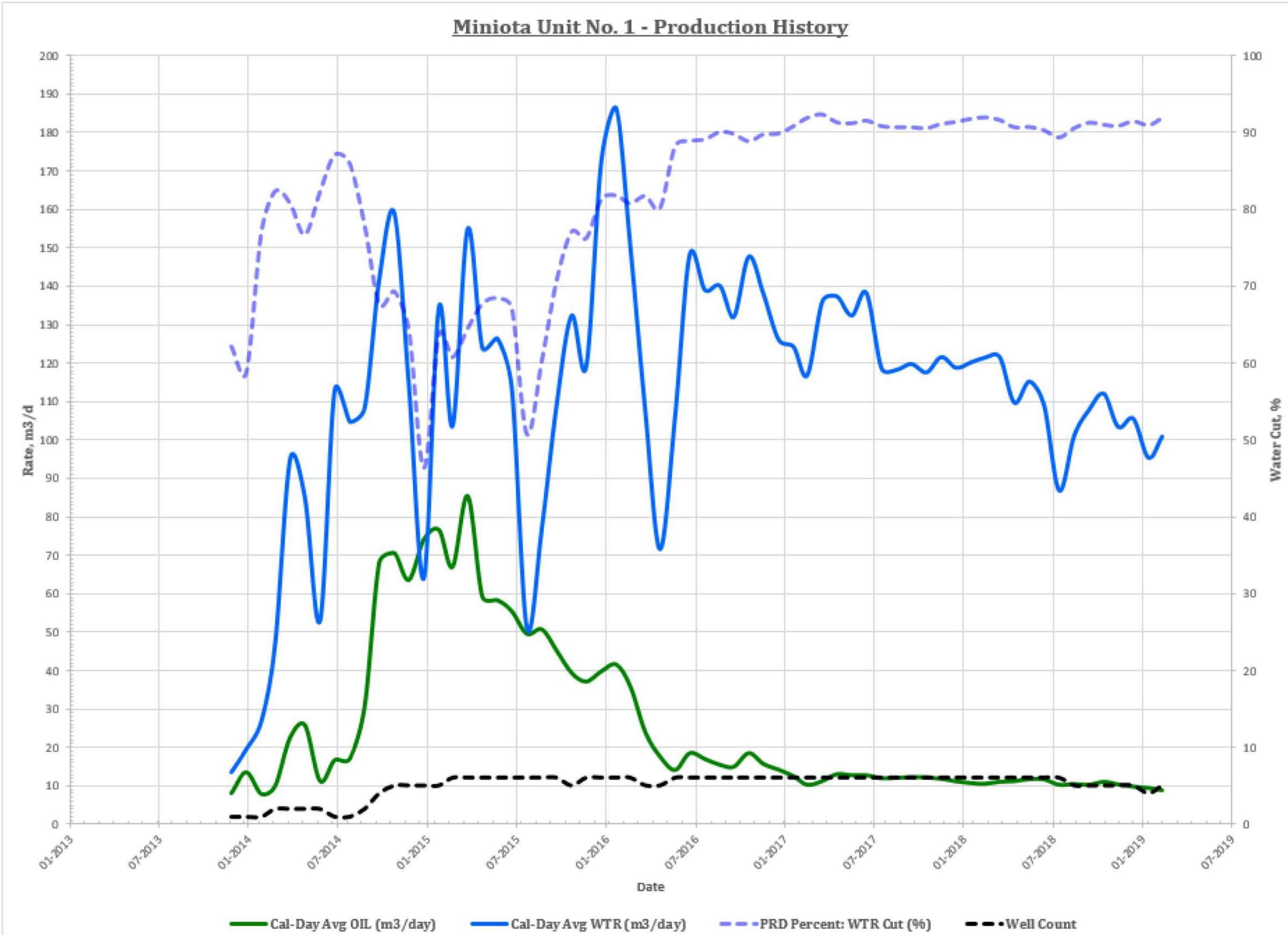
Location		Depth (m MD)	Length (m)	K-Max (mD)	Permeability K-90 (mD)	K-Vert (mD)	Porosity% (%)	Grain Density (kg/m3)	Bulk Density (kg/m3)	Lithology
12-01-013-27W1	FD	543.71	0.57	2.97	2.73	0.63	7.2%	2810	2610	NA
12-01-013-27W1	FD	544.52	0.27	3.27	1.77	1.28	11.7%	2700	2380	NA
12-01-013-27W1	FD	544.79	0.58	19.50	2.49	0.42	10.2%	2690	2420	NA
12-01-013-27W1	FD	545.37	0.22	8.78	5.65	0.01	8.3%	2830	2590	NA
12-01-013-27W1	FD	545.59	0.39	11.30	1.71	0.24	13.2%	2820	2440	NA
12-01-013-27W1	FD	545.98	0.21	4.90	0.57	0.01	8.9%	2820	2560	NA
12-01-013-27W1	FD	546.19	0.29	0.11	0.08	NA	3.3%	2820	2730	NA
Average							9.0%			
Average							11.7%			
13-06-013-26W1	SP	554.00	0.49	NA	NA	NA	5.9%	2810	2640	dol,i,ppv,sv,calc
13-06-013-26W1	FD	554.49	0.36	3.53	1.92	4.24	6.4%	2690	2520	ls,i,ppv,cht
13-06-013-26W1	SP	555.40	0.34	3.38	NA	NA	10.4%	2830	2540	dol,i,ppv,sshy,cht
13-06-013-26W1	FD	555.74	0.39	0.89	0.74	0.38	16.3%	2840	2380	dol,i,ppv,calc
13-06-013-26W1	FD	556.13	0.48	1.44	0.91	0.16	17.9%	2850	2340	dol,i,calc,cht
13-06-013-26W1	FD	556.61	0.30	0.08	0.05	NA	7.2%	2850	2650	dol,i,cht
13-06-013-26W1	SP	556.91	0.30	NA	NA	NA	5.4%	2840	2690	dol,i,pyr
Average							9.9%			
Average							14.9%			
05-06-013-26W1	SP	536.34	0.42	0.38	NA	NA	9.1%	2690	2450	ls,i,ppv
05-06-013-26W1	FD	536.76	0.35	0.15	0.09	NA	4.9%	2700	2570	ls,i,ppv,sv,cht
05-06-013-26W1	SP	537.11	0.20	0.82	NA	NA	1.7%	2820	2770	dol,i,ppv
05-06-013-26W1	SP	537.31	0.12	NA	NA	NA	2.2%	2820	2760	dol,i,ppv
05-06-013-26W1	FD	537.43	0.32	1050.00	889.00	352.00	12.1%	2820	2480	dol,i,ppv,sv,calc,cht
05-06-013-26W1	SP	537.75	0.40	11.10	NA	NA	20.6%	2820	2240	dol,i,ppv
05-06-013-26W1	FD	538.15	0.36	658.00	429.00	0.60	20.3%	2810	2240	dol,i,ppv,sv,calc
Average							10.1%			
Average							17.7%			
07-01-013-27W1	SP	537.57	0.26	0.83	NA	NA	6.7%	2820	2630	dol,i,ppv
07-01-013-27W1	FD	537.83	0.20	2.02	0.65	0.73	11.7%	2830	2500	dol,i,ssdy,frac
07-01-013-27W1	FD	538.03	0.21	2.72	1.42	1.28	21.4%	2840	2230	dol,i,slt,ssdy
07-01-013-27W1	FD	538.24	0.33	0.20	0.20	0.02	10.3%	2830	2540	dol,i,ssdy
Average							12.5%			
Average							14.5%			
04-01-013-27W1	SP	562.91	0.20	NA	NA	NA	6.0%	2830	2660	dol,i,anhy,pyr,frac
04-01-013-27W1	SP	563.11	0.18	NA	NA	NA	17.6%	2730	2250	ls,i,anhy,rbl
04-01-013-27W1	FD	564.15	0.20	12.10	11.70	9.99	4.4%	2850	2720	dol,i,ppv,sv
04-01-013-27W1	FD	564.52	0.22	1.46	0.86	0.06	12.4%	2850	2500	dol,i,calc
04-01-013-27W1	SP	564.74	0.18	0.31	NA	NA	13.2%	2830	2460	dol,i
04-01-013-27W1	FD	564.92	0.22	19.30	9.84	0.09	14.1%	2890	2480	dol,i,ppv,sv,sshy,calc
04-01-013-27W1	FD	565.14	0.17	3.40	2.14	0.24	14.9%	2850	2430	dol,i,sdy,sshy,calc
04-01-013-27W1	FD	565.31	0.26	83.60	55.10	0.04	9.2%	2820	2560	dol,i,ppv,sv,ssdy
04-01-013-27W1	FD	565.57	0.27	38.00	15.60	3.94	9.3%	2830	2570	dol,i,ppv,sv
04-01-013-27W1	SP	565.84	0.26	NA	NA	NA	10.1%	2820	2540	dol,i,ppv,sv
04-01-013-27W1	SP	566.23	0.14	0.66	NA	NA	13.7%	2790	2410	dol,i,ppv
04-01-013-27W1	SP	566.37	0.20	11.50	NA	NA	16.1%	2800	2350	dol,i,ppv
04-01-013-27W1	FD	566.57	0.19	29.80	10.70	1.36	15.4%	2820	2390	dol,i,ppv,calc
04-01-013-27W1	FD	566.76	0.28	337.00	1.97	0.40	16.0%	2820	2360	dol,i,sshy
04-01-013-27W1	FD	567.04	0.21	1.79	1.34	0.64	13.9%	2810	2420	dol,i,ppv,sv,anhy
Average							13.2%			
Average							14.3%			
16-01-013-27W1	FD	531.98	0.26	14.0	9.16	2.99	6.4%	2710	2540	ls,i,ppv
16-01-013-27W1	SP	532.24	0.13	109.0	NA	NA	7.1%	2700	2510	ls,i,ppv
16-01-013-27W1	SP	532.58	0.36	0.6	NA	NA	8.6%	2830	2590	dol,i,ppv,cht
16-01-013-27W1	SP	532.94	0.31	0.1	NA	NA	6.8%	2690	2510	ls,i,ppv
16-01-013-27W1	FD	533.33	0.38	352.0	196	14.3	13.9%	2830	2440	dol,i,ppv,sv,sshy,cht
16-01-013-27W1	FD	533.71	0.38	0.0	0.02	NA	10.5%	2850	2550	dol,i,ppv,sv
16-01-013-27W1	FD	534.09	0.19	0.5	NA	NA	12.5%	2820	2470	dol,i,ppv,sv
Average							9.4%			
Average							12.3%			

Appendix C: Reservoir Characteristics and Recovery

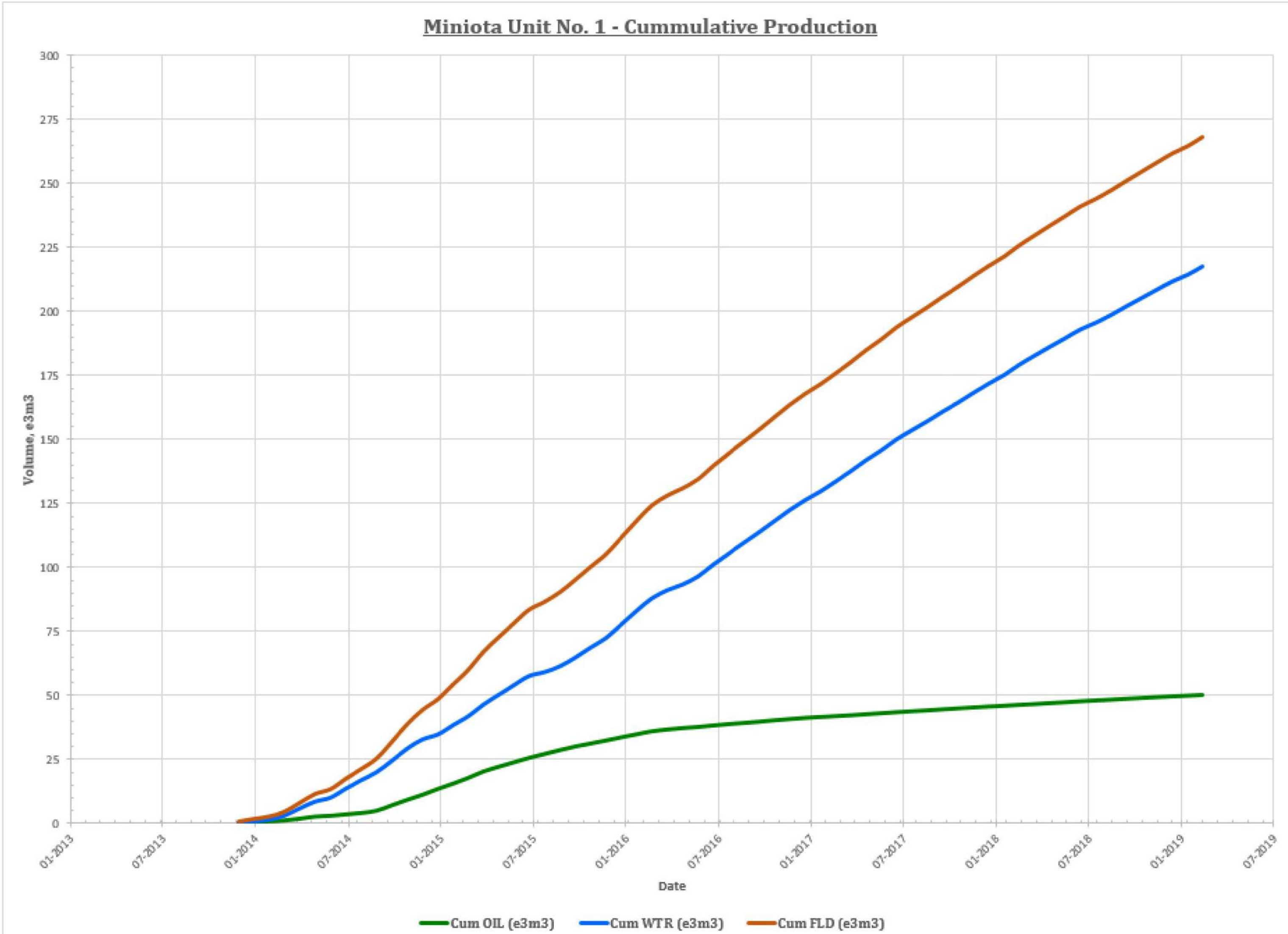
Appendix C, Figure 1: Miniota Unit No. 1 Original Oil in Place

Quarter	*Legal Description*	*Control Well UWI*	*Minerals*	*Area (ha)*	*Net Pay (m)*	*Porosity (%)*	*Water Sat (%)*	*1/Bo (m3/rm3)*	*OOIP (m3)*
SW-01-013-27W1	03-01-013-27W1	(03-01) 100/03-02-013-27W1	Freehold	16.00	2.20	17.64%	40.00%	0.95	35,362
	04-01-013-27W1	100/04-01-013-27W1	Freehold	16.00	2.20	17.64%	40.00%	0.95	35,362
	05-01-013-27W1		Freehold	16.00	2.20	17.64%	40.00%	0.95	35,362
	06-01-013-27W1		Freehold	16.00	2.20	17.64%	40.00%	0.95	35,362
SE-01-013-27W1	01-01-013-27W1		Freehold	16.00	1.20	17.00%	35.83%	0.95	19,884
	02-01-013-27W1		Freehold	16.00	1.20	17.00%	35.83%	0.95	19,884
	07-01-013-27W1	100/07-01-013-27W1	Freehold	16.00	1.20	17.00%	35.83%	0.95	19,884
	08-01-013-27W1		Freehold	16.00	1.20	17.00%	35.83%	0.95	19,884
NW-01-013-27W1	11-01-013-27W1		Freehold	16.00	1.80	15.83%	40.00%	0.95	25,975
	12-01-013-27W1	100/12-01-013-27W1	Freehold	16.00	1.80	15.83%	40.00%	0.95	25,975
	13-01-013-27W1		Freehold	16.00	1.80	15.83%	40.00%	0.95	25,975
	14-01-013-27W1		Freehold	16.00	1.80	15.83%	40.00%	0.95	25,975
NE-01-013-27W1	09-01-013-27W1		Freehold	15.50	1.50	17.13%	36.67%	0.95	23,955
			Crown	0.50	1.50	17.13%	36.67%	0.95	769
	10-01-013-27W1		Freehold	16.00	1.50	17.13%	36.67%	0.95	24,724
	15-01-013-27W1		Freehold	16.00	1.50	17.13%	36.67%	0.95	24,724
	16-01-013-27W1	100/16-01-013-27W1	Freehold	15.76	1.50	17.13%	36.67%	0.95	24,355
			Crown	0.24	1.50	17.13%	36.67%	0.95	369
SW-06-013-27W1	03-06-013-26W1		Freehold	16.00	1.60	17.25%	36.25%	0.95	26,727
	04-06-013-26W1		Freehold	15.38	1.60	17.25%	36.25%	0.95	25,689
			Crown	0.62	1.60	17.25%	36.25%	0.95	1,038
	05-06-013-26W1	100/05-06-013-26W1	Freehold	15.38	1.60	17.25%	36.25%	0.95	25,689
			Crown	0.62	1.60	17.25%	36.25%	0.95	1,038
	06-06-013-26W1		Freehold	16.00	1.60	17.25%	36.25%	0.95	26,727
NW-06-013-27W1	11-06-013-26W1		Freehold	16.00	1.20	14.50%	37.50%	0.95	16,519
	12-06-013-26W1		Freehold	16.00	1.20	14.50%	37.50%	0.95	16,519
	13-06-013-26W1	100/13-06-013-26W1	Freehold	16.00	1.20	14.50%	37.50%	0.95	16,519
	14-06-013-26W1		Freehold	16.00	1.20	14.50%	37.50%	0.95	16,519
Total/Average	***24***	***7***		***384.00***	***1.58***	***16.67%***	***38.00%***	***0.95***	***596,766***

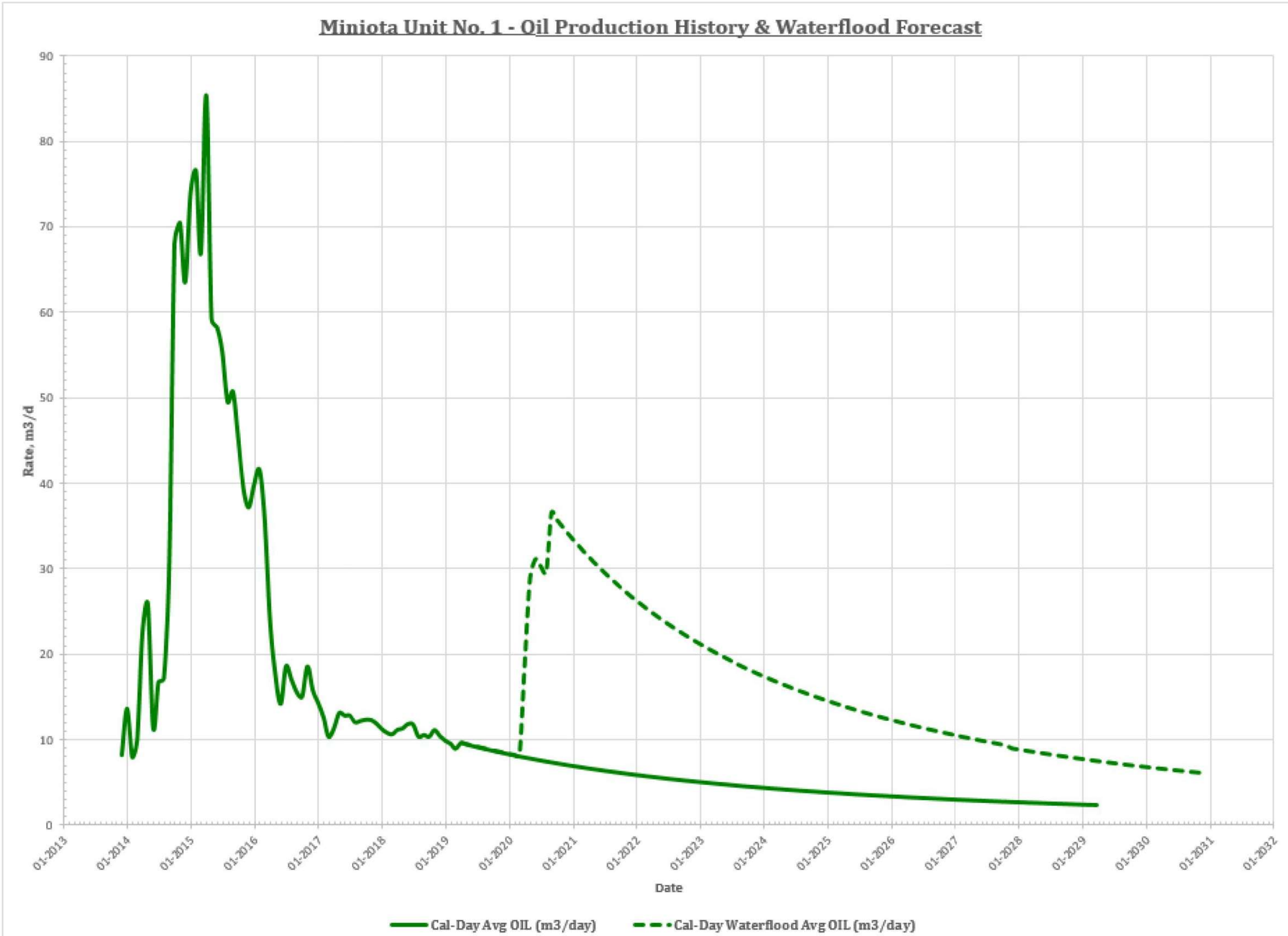
Appendix C, Figure 2: Miniota Unit No. 1 Production History



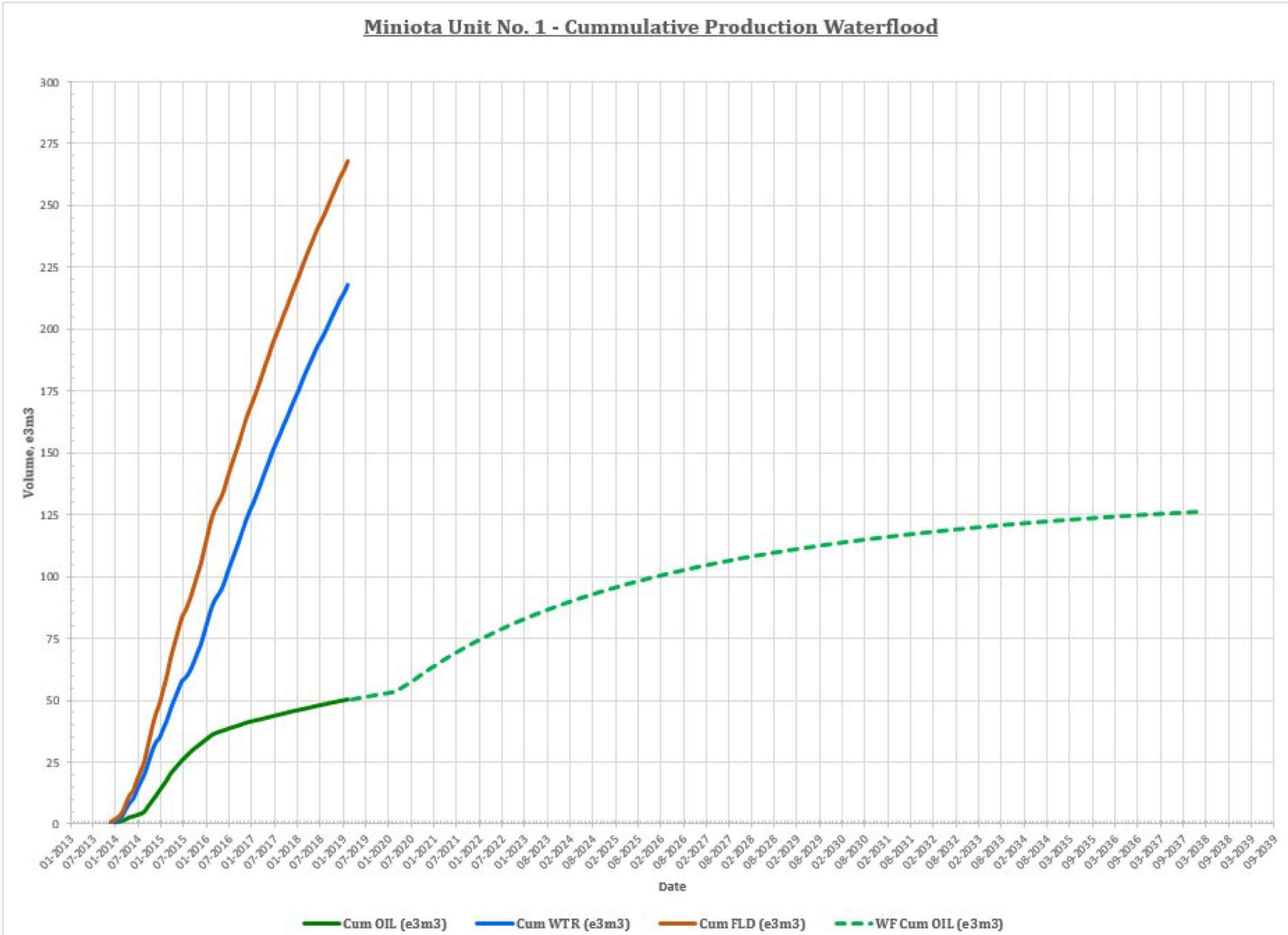
Appendix C, Figure 3: Miniota Unit No. 1 Cummulative Production



Appendix C, Figure 4: Miniota Unit No. 1 Production Forecast



Appendix C, Figure 5: Miniota Unit No. 1 Cumulative Production and Waterflood Forecast


Miniota Unit No. 1 - Cummulative Production Waterflood
Volume, e3m3
Date
Cum OIL (e3m3)
Cum WTR (e3m3)
Cum FLD (e3m3)
WF Cum OIL (e3m3)

Appendix D: Proposed Waterflood Design

Appendix D, Figure 1: Water Injector Wellbore

Data-Driven Downhole Diagram

Operator: Elcano Exploration Inc. Reporting To: Dale Barnard Consultant: Craig Schad Tel2: Tel1: 306-471-7417

UWI: 100.03-02-013-27W1.00		WELL: Elcano Miniota HZNTL 03-02-13-27WPM
LICENCE #:10389		SPUD DATE:16-Aug-2015
KB: 474.0	KB-GL: 4.9	GL: 471.1
KB-CBF: 4.5	KB-THF: 0.8	PBTD: 2354.9

Multi-Leg Information

Leg #	Kick-Off Point	Liner Top	TMD	TVD
1	0.00	0.00	0.00	0.00
2	0.00	0.00	0.00	0.00
3	0.00	0.00	0.00	0.00
4	0.00	0.00	0.00	0.00

Casing Summary

Description	O.D. (mm)	Wt. (kg/m)	Grade	Thread	Set At (mKB)	Landed At (mKB)

Cement Summary

Production

Filled w/ 13T PROLITE-1400
Tailed w/ 25T ProLITE-1600

Completions Summary

#	Qty. (#)	O.D. (mm)	I.D. (mm)	Wt. (kg/m)	Grade	Thread	Description	Length (m)	Set At (mKB)	Landed At (mKB)
1	1	73.0	62.0	9.67	J-55	EUE	WL Set Permanent Bridge Plug	0.50	562.50	563.00
2	2	73.0	62.0	9.67	J-55	EUE	Tubing Perforated	15.00	547.50	562.50
3	1	73.0	62.0	9.67	J-55	EUE	Hydraulic Set Double Grip Packer	1.50	546.00	547.50
4	59	73.0	62.0	9.67	J-55	EUE	Tubing	535.13	10.87	546.00
5	1	73.0	62.0	9.67	J-55	EUE	Tubing Pup Joint	6.37	4.50	10.87

Weight on String

Packer: daN, Tubing: daN, Hanger: daN
Total String Weight: 6186 daN, Str. or Slackoff -/+: daN, Landed String Wt.: daN
String Length: 652.34 m, Correction +/-: 0.00 m, Adjusted Length: 652.34 m

Perforation Summary

Amaranth : 553.0 mKB - 558.6 mKB at 17 SPM, 0.0 kPa

Remarks

Tubing is coated TK99

Directions to Site

From Virden West on Hwy #1 to Hwy #83 trun go north to range road #73N trun and go west 0.5km trun north in to location.

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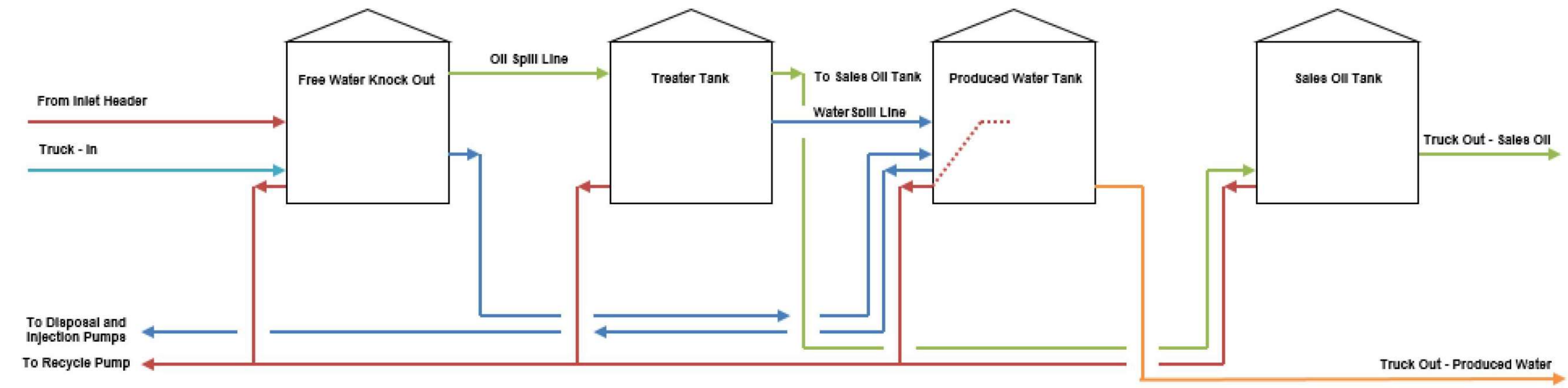
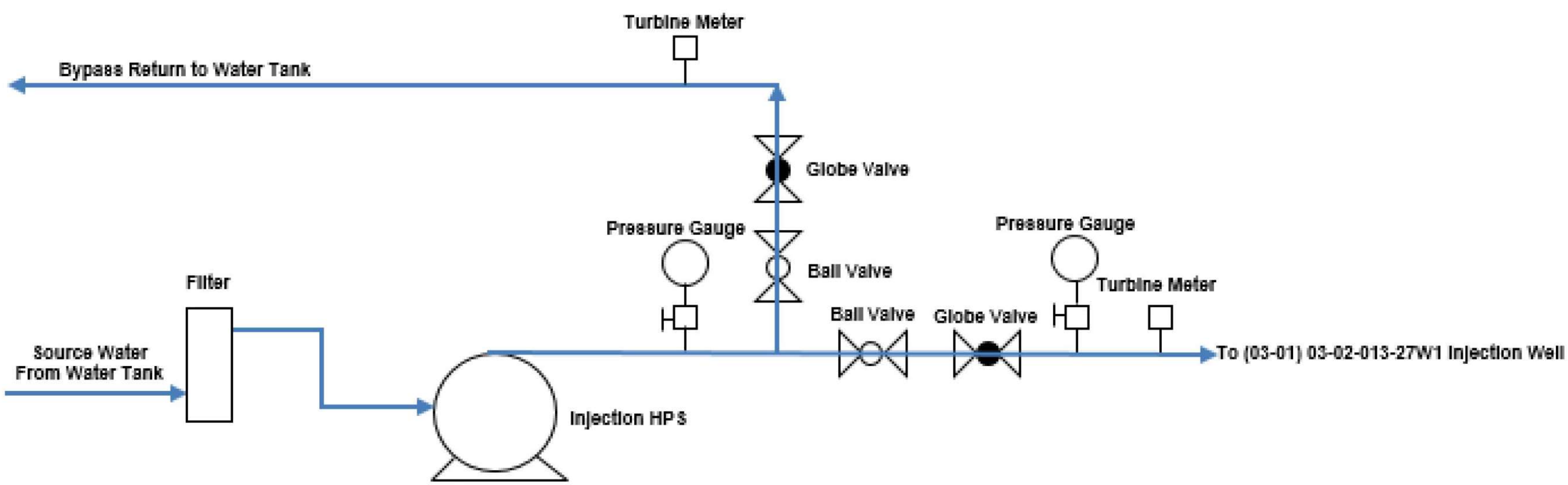
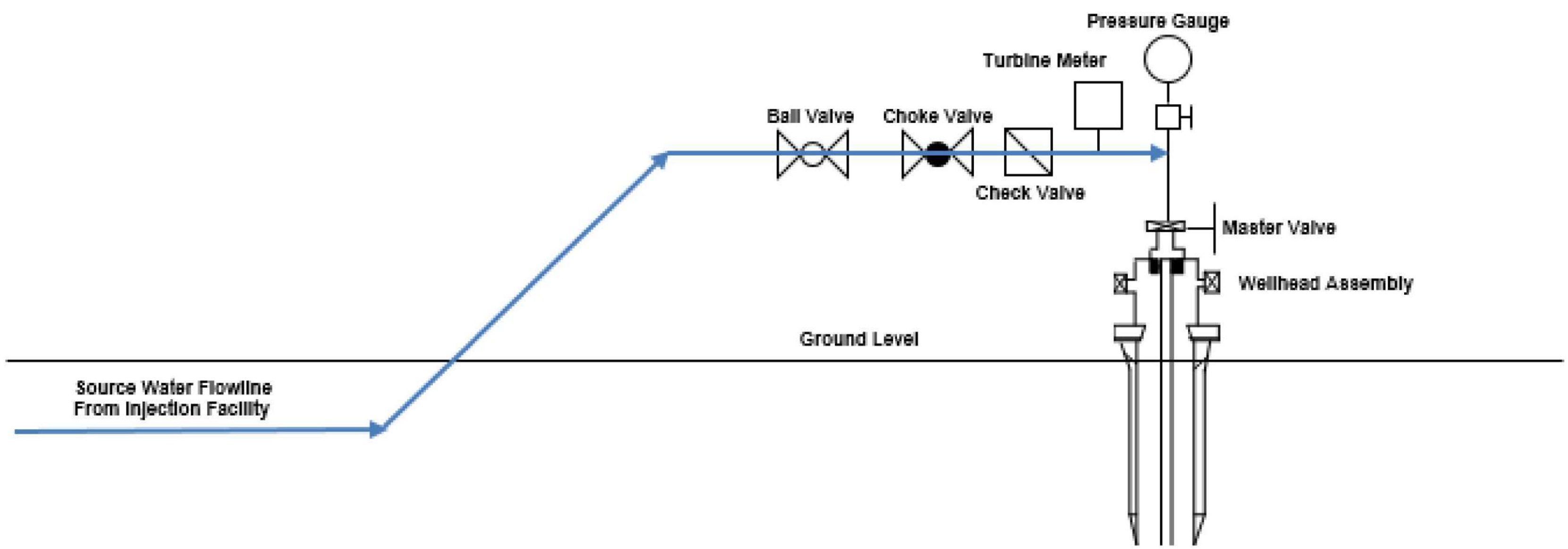
Appendix D, Figure 2: Injection Facility Design





Appendix D, Figure 3: Injector Well Configuration



Appendix D, Figure 4: Corrosion Control

Miniota Unit No. 1 – Corrosion Control Program

Surface Lines:

- All surface flow lines are constructed of corrosion resistant composite 'Flexpipe' line pipe with an MOP of 5,171 kPa;
- All surface injection lines will be constructed of corrosion resistant composite 'Flexcord' line pipe with an MOP of 13,790 kPa;
- Fiberglass fittings will be used where applicable, valve internals will be stainless steel;
- Isolation valves at wellheads, injection facility and risers;
- High and low pressure shut-down.

Injection Facilities:

- Internally coated storage tanks;
- Stainless steel filtration system with 10 micron filter socks;
- HPS consisting of 36 stage 675-9000-TA, 319 stainless steel head and base.

Injection Well:

- Injection tubing will be internally coated;
- Casing, tubing and wellhead cathodic protection;
- Fiberglass fittings will be used where applicable, valve internals will be stainless steel;
- Inhibited water in annular space.

Producing Wells:

- Downhole corrosion inhibitor batch treatments and/or continuous injection of corrosion inhibitor Cathodic protection