Connacher Performance Presentation - 2015





Forward Looking Information and Advisories



This presentation contains forward looking information including, expectations for future production and total bitumen recovery, estimates of reserves, future development of the **SAGD+®** process commercial project at Algar and mini-steam expansion at Pod One and the anticipated impact thereof, growth potential associated with certain additional capital investment options and development projects to be undertaken at Algar, sustainability of production, well and plant performance, the steam to oil ratio ("SOR"), and plant reliability.

Forward looking information is based on management's expectations regarding the Company's future growth and financial position; results of operations and production, future commodity prices and foreign exchange rates; future capital and other expenditures (including the amount, nature, and sources of funding thereof), plans for and results of drilling activity; environmental matters; business prospects and opportunities; and future economic conditions. Forward looking information involves significant known and unknown risks and uncertainties, which could cause actual results to differ materially from those anticipated. These risks include, but are not limited to: the risks associated with the oil and gas industry (e.g., operational risks in development, exploration and production; delays or changes in plans with respect to exploration or development projects or capital expenditures; the uncertainty of reserve and resource estimates; the uncertainty of geological interpretations; the uncertainty of estimates and projections relating to production, costs and expenses; and health, safety and environmental risks), risk of commodity price and foreign exchange rate fluctuations, risks associated with the impact of general economic conditions, risks and uncertainties associated with maintaining the necessary regulatory approvals and securing the financing to proceed with the operation and continued expansion of the Great Divide oil sands project.

This presentation includes information pertaining to the reserves as at December 31, 2014, as evaluated by GLJ Petroleum Consultants Ltd., in their report for the year ended December 31, 2014 (the "GLJ Report"). Statements relating to reserves are deemed to be forward looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves described exist in the quantities predicted or estimated, and can be profitably produced in the future. Certain information and assumptions relating to the reserves reported herein are set out in the Corporation's Annual Information Form for the year ended December 31, 2014, which is available on the System for Electronic Document Analysis and Retrieval (SEDAR) at www.sedar.com. There is no assurance that the forecast price and cost assumptions contained in the GLJ Report will be attained and variances could be material. The reserves estimates of Connacher's properties described herein are estimates only. The actual reserves on Connacher's properties may be greater or less than those calculated.

Design capacity is not necessarily indicative of the stabilized production levels or steam generation capacity that may ultimately be achieved at Connacher's SAGD project sites. Reported average production levels may not be reflective of sustainable production rates and future production rates may differ materially from the production rates reflected in this presentation due to, among other factors, difficulties or interruptions encountered during the production of bitumen.

Although Connacher believes that the expectations in such forward looking information are reasonable, there can be no assurance that such expectations shall prove to be correct. The forward looking information included in this presentation is expressly qualified in its entirety by this cautionary statement. The forward looking information included herein is made as of the date of this presentation and Connacher assumes no obligation to update or revise any forward looking information to reflect new events or circumstances, except as required by law.

Agenda



Subsurface Presentations	
Background	Gord Trainor
Geology	Gord Trainor
Recovery Process	Ryan Cross and Tyson Noble
Completions & Arificial Lift, Monitoring	Tyson Noble
Scheme Performance	Ryan Cross
Future Plans (Existing Developments)	Ryan Cross

Surface Presentations				
Facilities	Behrang Nafchi and Merv Pond			
Measurement & Reporting	Behrang Nafchi			
Water Recycle	Behrang Nafchi			
Future Plans	Behrang Nafchi			

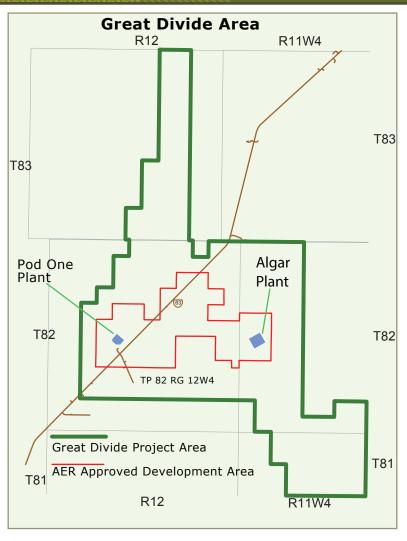




Assets



- Connacher is a focused developer, producer, and bitumen marketer from its in-situ oil sands projects in Alberta's Athabasca oil sands.
- Primary driver of value is the expansion and continued development of its bitumen production at its Great Divide oil sands operations using in-situ recovery methods
- Oil sands reserves and resources include 441,032 Mbbl of 2P reserves (as of 31 December 2014 per GLJ Petroleum Consultants) (1)



⁽¹⁾ See Slide AppendixB for Reserve Definitions

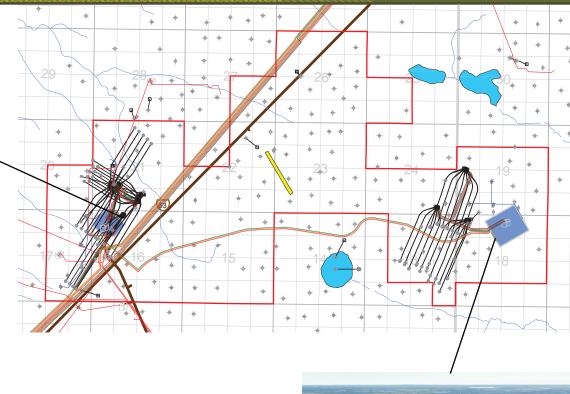
Great Divide Assets





Pod One

- First Steam September 2007
- First Bitumen October 2007



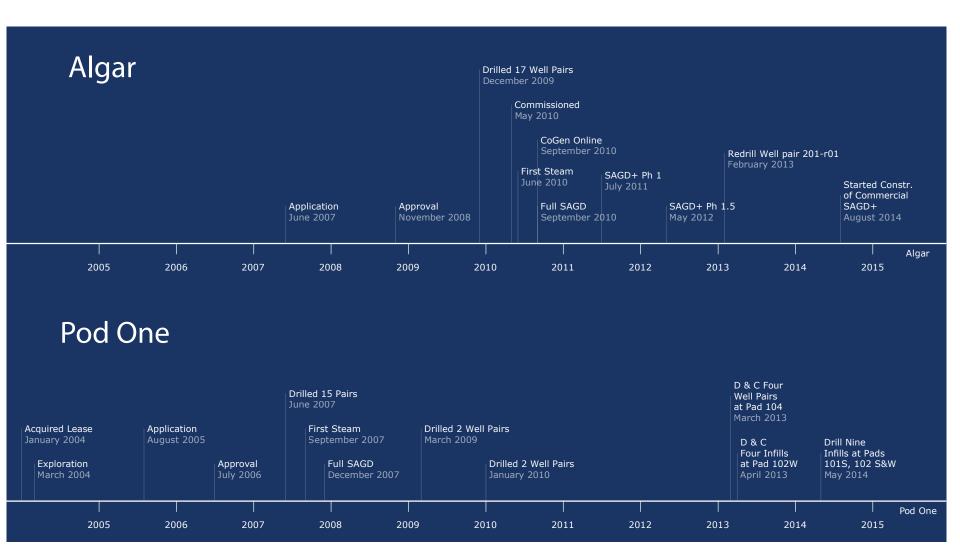
Algar

- First Steam May 2010
- First Bitumen July 2010



Great Divide - Development History

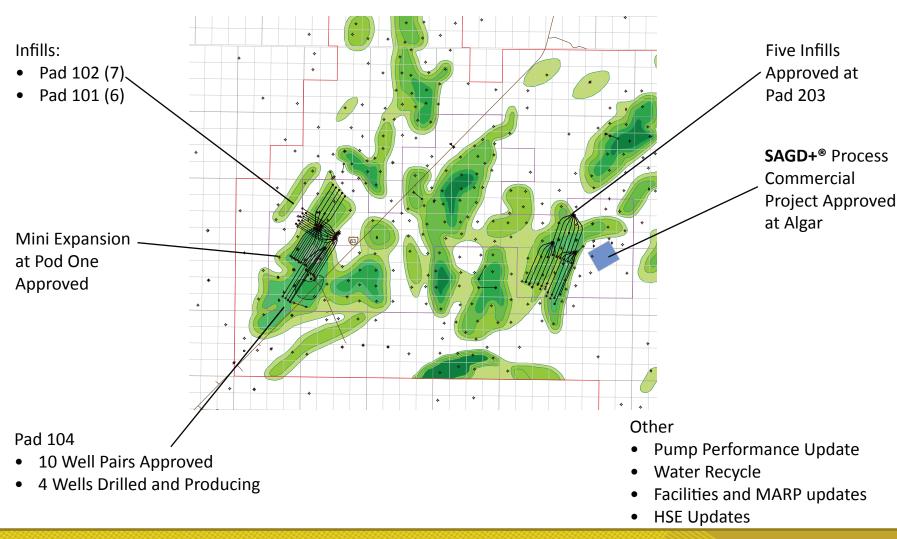




Highlights - 2015 Connacher Presentation

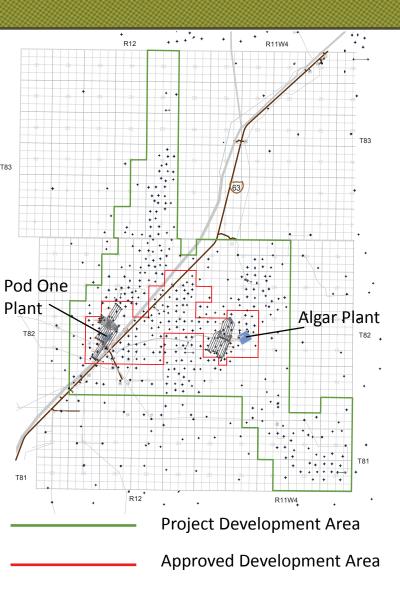


No Changes to Net Pay and other Geology Maps



Great Divide (Approval 10587) Development





Pod One Current Development

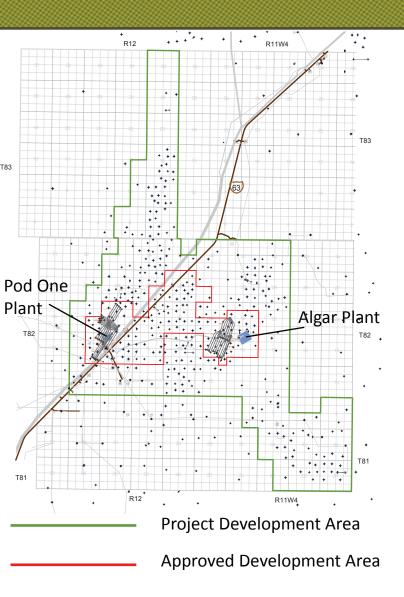
- 23 Well Pairs and 13 Infills producing
 - Pad 101N 5 Well Pairs
 - Pad 101S 6 Well Pairs, 6 Infills
 - Pad 102W 5 Well Pairs, 5 Infills
 - Pad 102S 3 Well Pairs, 2 Infills
 - Pad 104 4 Well Pairs 80m interwell spacing

Pod One Development History

- Original 15 Well Pairs Drilled in 2007
- all well pair interwell spacing 100m except Pad 104
- 2 Well Pairs Drilled in 2009 (101S and 102S)
- 2 Well Pairs Drilled in 2010 (102S)
- 4 Infills Drilled in 2013 (102W)
- 4 Well Pairs Drilled in 2013 (104)

Great Divide (Approval 10587) Development





Algar Current Development

- 18 Well Pairs Producing
 - Pad 201S 5 Well Pairs 100m interwell spacing
 - Pad 202S 6 Well Pairs (1 re-drill) 100m interwell spacing
 - Pad 203S 7 Well Pairs 100m interwell spacing

Algar Development History

- Original 17 Well Pairs Drilled in 2009
- Replacement Well Pair (202-01) drilled in 2013
- Approved for 5 Infills on Pad 203 in 2014

Great Divide Summary



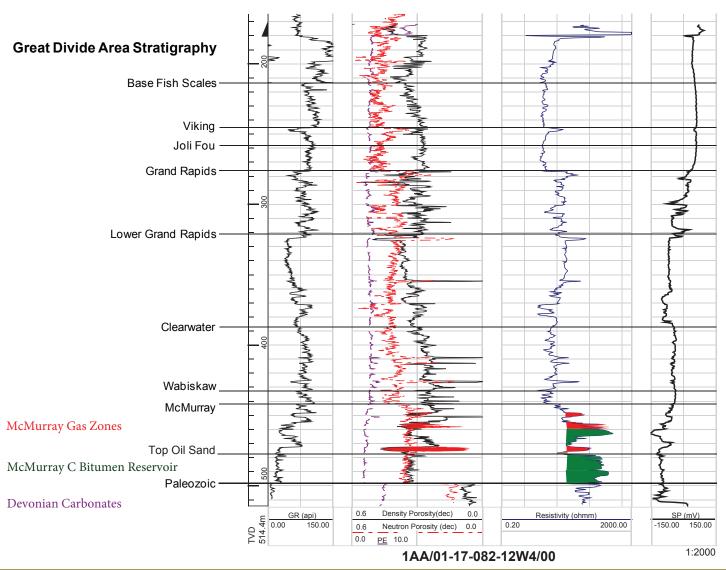
	Pod One @ Sept 30, 2015	Algar @ Sept 30, 2015
First Steam	September 2007	May 2010
First Sales Oil	October 2007	June 2010
Cumulative Bitumen Produced e ³ m ³	3,023	1,831
Cumulative Steam Injected e ³ m ³	11,500	8,293
Cumulative SOR	3.80	4.53
Number of Producing Well Pairs	23	18
Number of Circulating Well Pairs	0	0
Infill Wells Producing	11	0
Wells Using Gas Lift	0	15
Wells Using Downhole Pumps	34	3
Operating Pressure Gas Lift	NA	3850 - 3900 kPa
Operating Pressure Pump	1300 - 2980 kPa	3000 - 3800 kPa
Directive 51 Operating MOP	6205 kPa Maximum Operating Pressure	6205 kPa Maximum Operating Pressure





Great Divide Area Type Well

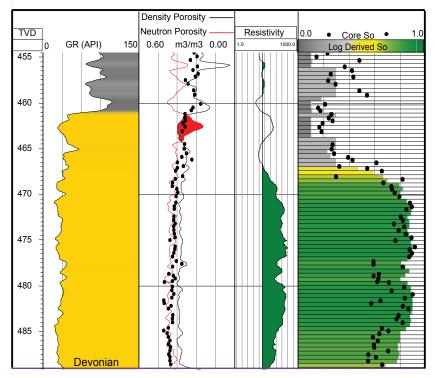




Great Divide Area Core & Log Data



Typical Composite Log with Interpretation and core data comparison.



1AA/13-16-082-12W4/00

- •Log vs Core Comparison
- •Analytical interpretation of geophysical logs to determine bitumen saturations (wt%) gives good correlation with core derived bitumen saturations (wt%). Examples shown below.

	Log	Core Net	Log Bitumen	Core Bitumen
Well	NetPay	Pay	Wt %	Wt %
100/08-17-082-12W400	21.3	23.3	13.6%	14.0%
1AA/03-17-082-12W400	13.2	12.0	11.6%	12.7%
1AA/03-21-082-12W400	14.9	13.3	10.2%	10.4%
1AA/07-16-082-12W400	25.9	27.7	11.5%	12.7%
1AA/10-21-082-12W400	20.8	17.2	13.2%	14.8%



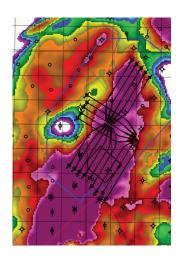
Great Divide Reservoir Parameters



	Pod One		Algar	
	Range	Average	Range	Average
Reservoir Thickness (m)	10 - 30	22	10 - 30	25
Depth to Top of Reservoir (m)	450 - 490	475	465 - 500	485
Reservoir Net Pay (m)	10 - 25	21	10 - 30	22
Oil Saturation (%)	75 - 85	80	72-80	76
Bitumen Density (kg/m3)		1018		1018
Bitumen Viscosity (cPs)	-	> 1 million		> 1 million
Porosity (%)	32 - 34	33	32 - 34	33
Vertical Permeability (mD)	1500 - 4000	, s	1500 - 4000	,=
Horizontal Permeability (mD)	2000 - 5000	=	2000 - 5000	-
Initial Reservoir Temperature (°C)		13		13
Initial Reservoir Pressure (kPa)		3500		4500
Initial Bottom Water Pressure (kPa)				2500

Great Divide Area - 3D Seismic



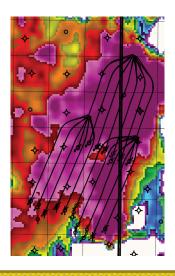


Pod One

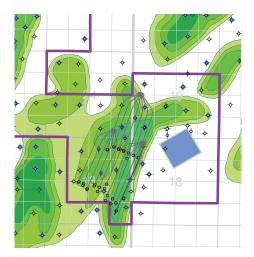


Net Pay (m)
10-15m
15-20m
20-25m
25-30m
>30m

3D Seismic - Interpreted McMurray Sand Isochron



Algar



3D Seismic has been successfully used by Connacher to define edges, sand thickness and paleo structure, and ultimately reduces the drilling costs.

No new Seismic was shot during the 2014-15 exploratory season.

Great Divide Area Oil Sands Facies and Pay



Zones

Defined by Vshale

Connacher Cut-Offs

Z1 (Sand): 0-10% fines **Z2** (Sandy IHS): 10-20% fines

Z3 (IHS): 20-50% fines **Z4** (Muddy IHS): 50-80%

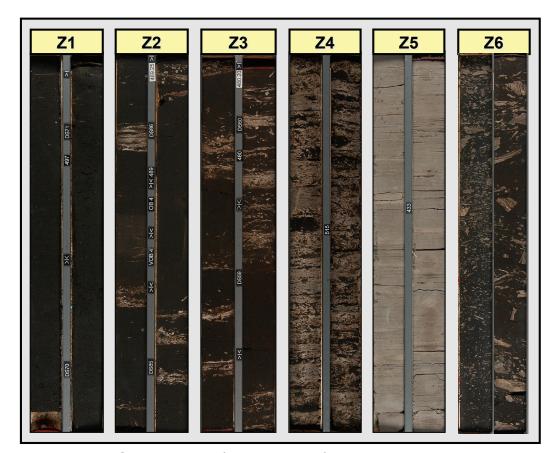
fines

Z5 (Mud): 80-100% fines **Z6** (Breccia): >10% clasts

Pay Base Criteria

Minimum bitumen grade: 7wt% Minimum Net/Gross ratio: 80 % Maximum included shale interval: 2m Minimum zone thickness: 10 m

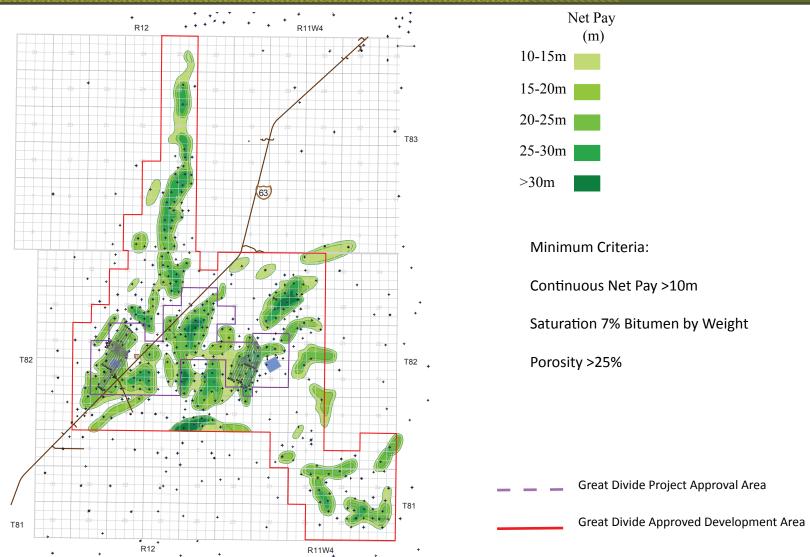




Core displayed is from a number of separate wells

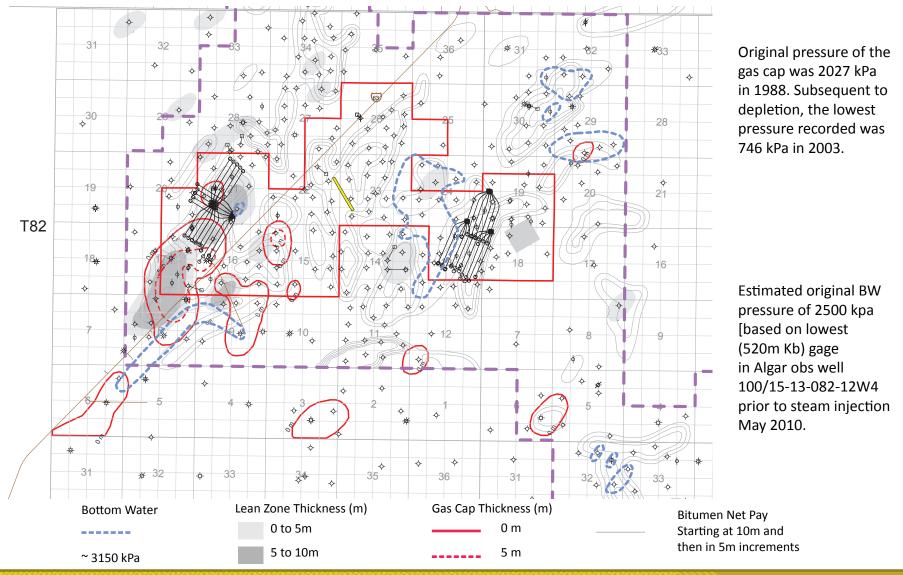
Net Pay Map Great Divide Area





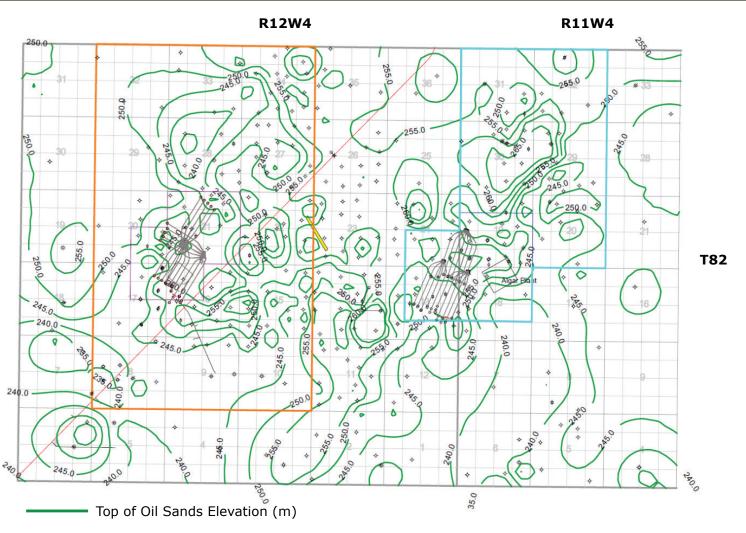
Combined Gas Cap & Lean Zone & Bottom Water Map





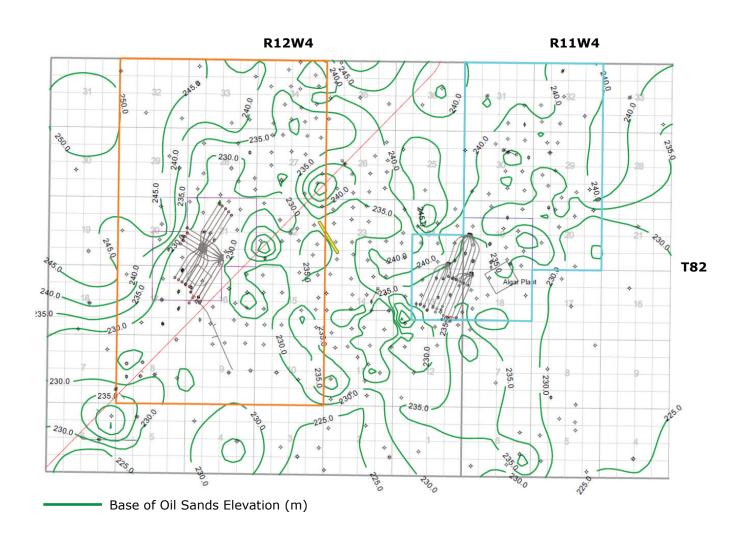
Top of Oil Sands Elevation





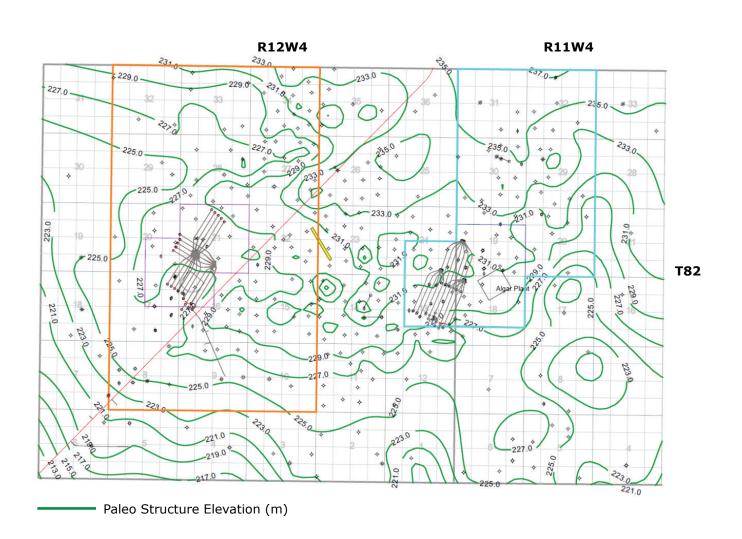
Base of Oil Sands





Paleo Structure Elevation

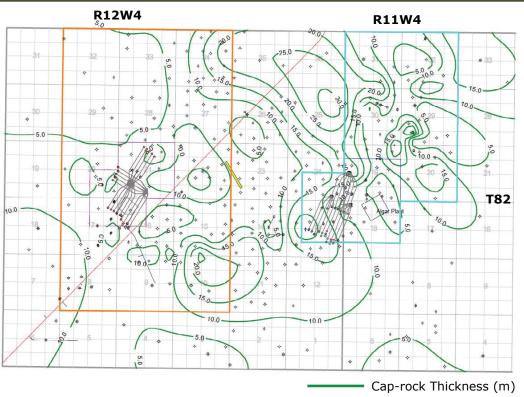




Cap Rock Integrity







The cap-rock in the Great Divide Area consists of a mixture of muddy inclined heterolithic strata (IHS) and a mudstone that average over 10 meters in thickness. The muddy IHS consists of 80% volume of shale that is bio-turbated with mud-lined and sand-filled burrows. Muddy IHS is interpreted to be deposited in a muddy point bar. The light grey mudstone is thinly bedded with the top containing siderite nodules and rootlets. It is interpreted to be deposited in a mud flat to swamp environment. Above are core photos of the cap rock from well 1AA/06-21-82-12W4.

Cap Rock Integrity - Mini Frac Tests



Results of the 1st Mini Frac at 1AB/14-27-082-12W4

Zone Tested	Test Interval (mKb)	BH Fracture Pressure (kPa)	Gradient (kPA/m)	Closure Pressure (kPa)
Clearwater Shale	390 - 395	8,463	21.7	5,805
Wabiskaw Shale	417 - 425	10,991	26.3	9,500
McMurray Shale	449 - 452	8,583	19.1	6,106
Mcmurray Oilsand	461 - 466	8,463	17.7	5,805

Wabiskaw

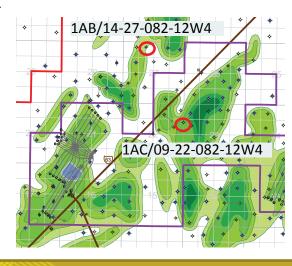
A Mini Frac test was conducted in well 1AB/14-27-082-12W4 in February 2010. Certain concerns were raised about one test being representative for the whole project area and also the closure pressure determined for the Wabiskaw which could have been influenced by local changes in rock mechanical properties.

Consequently a second test was conducted at 1AC/09-22-082-12W4 in April 2013, and this is reported in the table below.

Results for the second test are similar to the first. Although the Wabiskaw measured the highest stress gradient it was reduced from the first test.

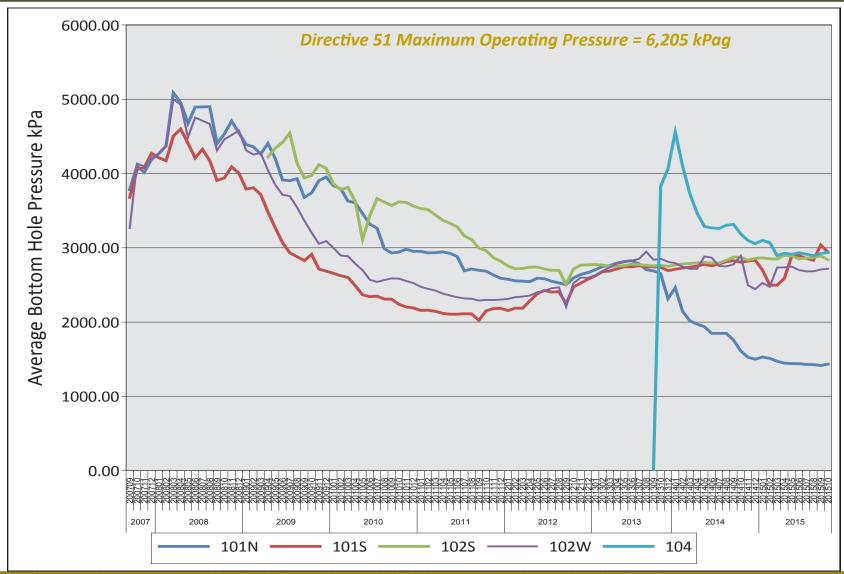
Results of the 2nd Mini Frac at 1AC/09-22-082-12W4

Zone Tested	Test Interval (mKb)	BH Fracture Pressure (kPa)	Gradient (kPA/m)	Closure Pressure (kPa)
Clearwater Shale	463 - 464	8,635	18.6	6,421
Wabiskaw Shale	474 - 475	10,534	22.2	7,917
McMurray Shale	481 - 482	8,057	16.7	6,155
Mcmurray Oilsand	517 - 518	6,503	12.6	5,397



Cap Rock Integrity - Pod One Monthly Average BH Injection Pressure





Cap Rock Integrity - Algar Monthly Average BH Injection Pressure



Directive 51 Maximum Operating Pressure = 6,205 kPag



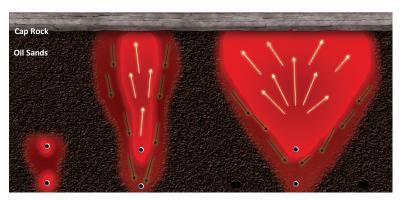




Great Divide SAGD Recovery Process



Basic Process



Circulation
High Pressure
~90 days
Steam Lift

Peak SAGD Production
High Pressure
~12 to 18 months
Gas Lift

Low Pressure SAGD Production Low Pressure ~4 to 6 years

Pumps

Additional Process

Pod One

- Pressure Balancing under a gas cap and lean zone
- Infill Wells
- Gas Cap Repressurization
- Natural Gas Co-injection (intermittent pressure maintenance)

Algar

- Pressure Balancing over a water zone
- SAGD+® Commercial Project
- Natural Gas Co-injection (intermittent pressure maintenance)

Technologies Developed/Developing

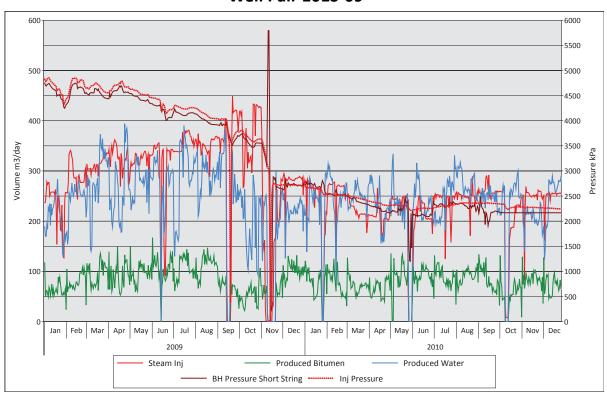


Description	Stage	Reason	Approvals
Pressure Balancing Under a Top Gas & Lean Zone & Bottom Water	Developed	 Eliminate steam losses into a gas and lean zone, lower SORs and improve productivity. Required the parallel development of reliability on high temperature downhole pumps. 	Operating within existing approvals
Gas Co-injection	Implemented	Natural gas can replace steam to maintain pressure	Approved for full field at Pod One Approved for full field at Algar
Gas Cap Repressurization	Implemented	Reduces steam losses into gas cap and lean zone	Approved
SAGD+® Process Trial / Commercial	 Trial Finished in 2 wells Commercial Project under construction 	Reduces bitumen viscosity lower than steam alone to improve production rates, SOR, and recovery.	Commercial SAGD+® Commercial Project approved at Algar
Infill Wells	11 Infills on production at Pod One October 30,2015	Additional production and reserves at low capital and SORs	Approved for 5 Infill Wells at Algar Pad 203

Pressure Balancing (Top Gas & Lean Zone)



Well Pair 101S-09



- Temporary production impact during pressure balance
- Improved SOR with low pressure operation
- Pad 104 is being operated in a similar manner except that the re-pressurization is expected to reduce the quantity of steam losses when the steam reaches the lean zone and pumps are being installed earlier

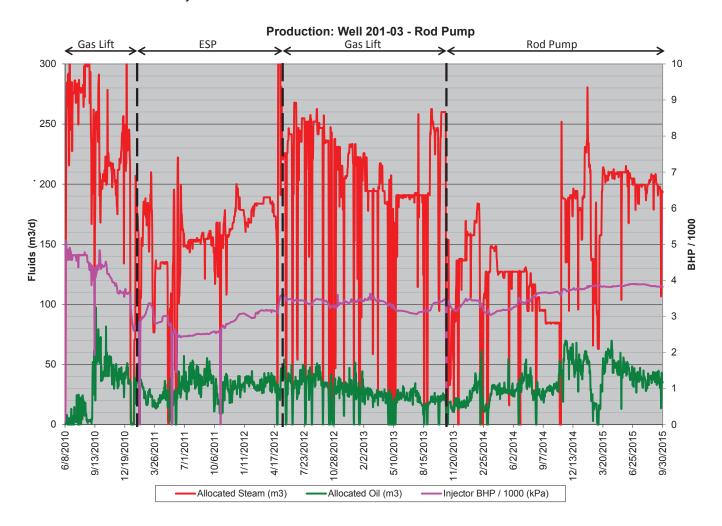
Note: Detailed description of the process provided in the attached technical paper presented by Connacher at the 2011 WHOC.

Pressure Balancing (Bottom Water)



Installed ESP to balance Inj Pressure with BW Pressure

Installed Steam Diverter



Re-Pressure Pod One Gas Cap

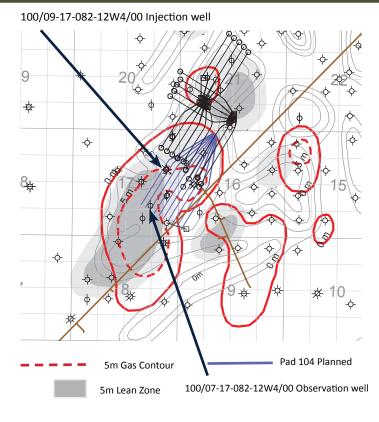


The purpose of gas cap re-pressuring is to increase the pressure in the gas cap and lean zone immediately above Pad 104 and institute a more effective pressure balancing process. Simulations had shown long term benefits to production and SOR by re-pressuring to just below the SAGD operating pressures (~2300 kPa in pump mode). Details of this are discussed in detail in the Pressure Balancing paper at Pod One which is attached to this presentation.

- The re-pressuring process was underway prior to the start up of Pad 104 in 2013. Methane was injected into the 9-17 well at the injection rates shown in the graph below.
- The gas cap pressure at the 7-17 observation well was approximately 1600 kPa prior to gas injection, and the average pressure for September 2015 was 2392 kPa in the gas cap and 2506 kPa in the lean zone.
- Currently the well is injecting just enough gas to maintain the pressure.

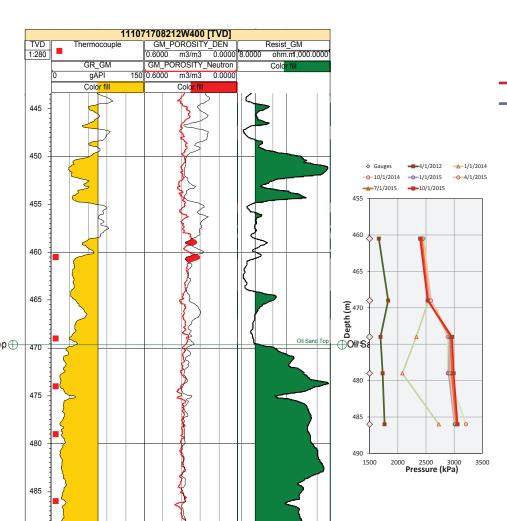
• The response to gas injection at the 7-17 observation well is shown in the following slide.

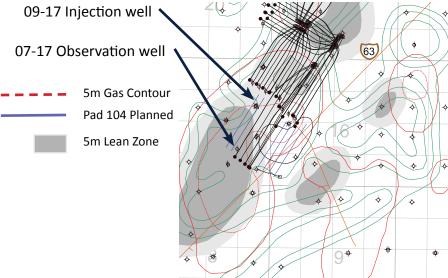




Re-Pressure Pod One Gas Cap







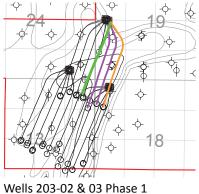
The chart shows the response at various pressure transducers in observation well 7-17 (approximately 600m south of the gas injection at 9-17). The transducers are set at the KB elevations shown on the adjacent log. The interesting observation from this data is the different responses in the gas cap and the lean zone which in this particular well is separated by approximately 3m of shale. The pressure response in the lean zone is noticeably faster than in the gas cap as shown in the lines connecting the chart and the log. From an operational perspective, Connacher is able to pressure the lean zone and gas cap to the target pressure of 2,400 kPa from the 9-17 gas injector.

SAGD+® Commercial Project



Phase 1

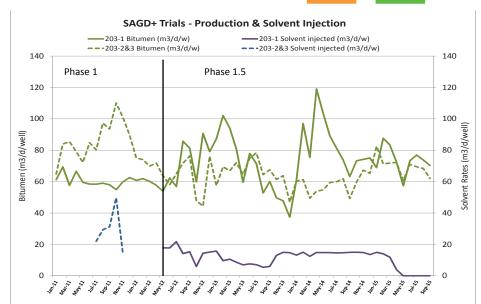
- In January 2011, ERCB granted approval for a trial of light hydrocarbon steam co-injection in the seven well pairs of Pad 203.
- Connacher selected two well pairs 203-2 and 203-3 for an initial test (Phase 1) of the process.
- In Phase 1, a commercially available solvent was co-injected with the steam starting in July 2011 at initial rates of approximately 10% by volume and increased to 15% by volume in October 2011. Compared to an April 2011 baseline, daily average per well bitumen production volumes during the months of August 2011 through October 2011 increased approximately 28% percent with a SOR decrease of 16%. The SOR decrease was limited by the necessity to increase steam injection rates to maintain normal operating pressure.
- Phase 1 injection ended November 2011. Solvent was recovered from the Phase 1 wells until April 2012 just prior to the start of Phase 1.5. 89% of the solvent had been recovered to surface.



Well 203-01 and 203-04 Phase 1.5

Phase 1.5

- Phase 1.5 commenced in May 2012 with solvent injection of approximately 10% until August when injection rates were reduced to approximately 6%, and further reduced in March 2013 to approximately 4%. In 2014 solvent injection rates averaged 5.9%.
- In the 12 months May 2012 through April 2013 bitumen rates increased by approximately 30% compared to the four months prior to the test. The SOR decreased 32% over the same period.
- In July 2013 an ESP was installed in 203-01. Following operational issues the pump was removed in December 2013. The bank of solvent built up during the ESP issues resulted in impoved results following the return to gas-lift.
- The SOR for Well 203-01 during the life of the test is 3.0 significantly lower than other wells in the project.
- Solvent injection was stopped in Well 203-1 on April 21, 2015.

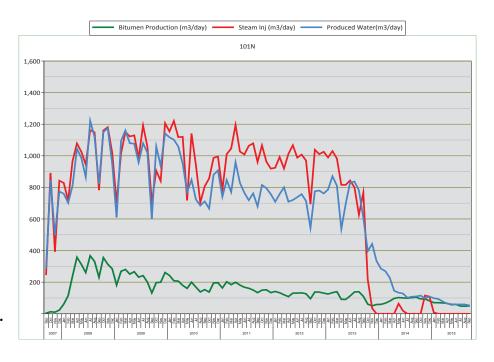


Note: details of the measurement of solvent injection and recovery are discussed in the attached Steam Solvent SAGD Paper and the Algar MARP

Pad 101N



- In May, 2014 steam was injected into 101-I01 and 101-I03 for ~ 2 weeks.
- This steam cycle did not yield any positive results beyond slightly increasing reservoir pressure.
- Currently there is no excess steam capacity at Pod
 One to inject into Pad 101N on a continous basis.
- Current strategy for 101N is to continue to produce using rod pumps.
- Oil cuts have remained steady since discontinuing steam injection, and range from 40 to 50 per cent.



NCG Co-injection



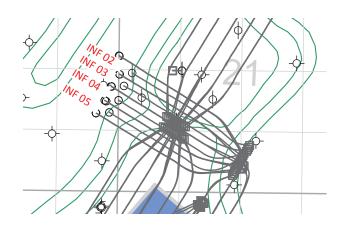
NCG Co-injection intended for pressure maintenance and ability to replace steam with NCG during times of steam shortage.

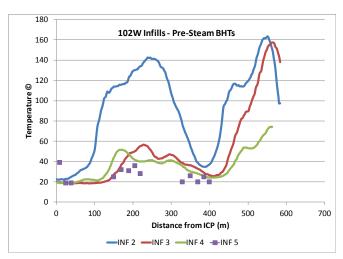
Commercial Scheme Approval issued for Full Field NCG Co-injection at all wells at Pod One and Algar:

- maximum of 10 e³ m³ per day
- limited to a maximum of 4 mole per cent with steam (monthly basis)
- limited to a maximum 20 per cent NCG replacement with steam (6 month average basis)

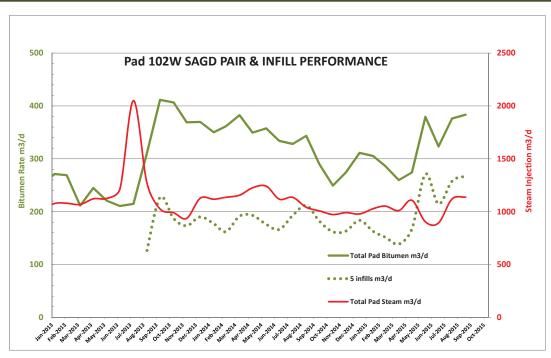
Infill Wells at Pod One - Pad 102W







Bottom Hole temperature surveys were carried out prior to steaming the infill wells.



- Infills were drilled shorter than the adjacent well pairs to avoid penetrating the thin channel edge
- Temperature logs prior to the steam injection indicated wide variations in temperatures along horizontal sections of the infill wells
- In order to increase temperature in the wells steam cycles were initiated as shown in the graph to the right
- Infill well 02 received the smallest volume of steam and responded the fastest and also had the highest temperature measured in the pre-steam survey.

New Infill Wells at Pod One - Pad 101/102



Pad	Infill Well	UWI	Production Start Date	Cum Oil Sept.30 2015(m3)
101S	101-INF07	109/16-17-082-12W4/0	N/A	N/A
101S	101-INF08	108/16-17-082-12 W4/0	Sept 13, 2014	30871
101S	101-INF09	105/09-17-082-12 W4/0	July 17, 2014	24856
101S	101-INF10	112/12-16-082-12 W4/0	July 24, 2014	26665
101S	101-INF11	114/12-16-082-12 W4/0	Aug 18, 2014	30181
101S	101-INF12	113/12-16-082-12 W4/0	Oct 4, 2014	24369
102W	102-INF06	112/08-20-082-12W4/00	May 3, 2015	13156
102W	102-INF13	115/12-16-082-12W4/00	N/A	N/A
102W	102-INF14	116/12-16-082-12W4/00	N/A	N/A







Typical bottom hole pressure and temperature measurement



Injector well BHP measurement:

 Blanket gas on annular side of the wellhead which is isolated from steam injection points for short and long strings

Producer well BHP measurement:

- Algar (gas lift), read by the short string lift gas pressure at surface. This is landed at the heel of the well. The annulus of the well, function as a bubble tube.
- Pod One, read by instrumentation coils which function as a bubble tube. This is landed at the
 toe of the well. The coil has a check valve at the end to prevent fluid from backing up inside.

Injector well BHT measurement

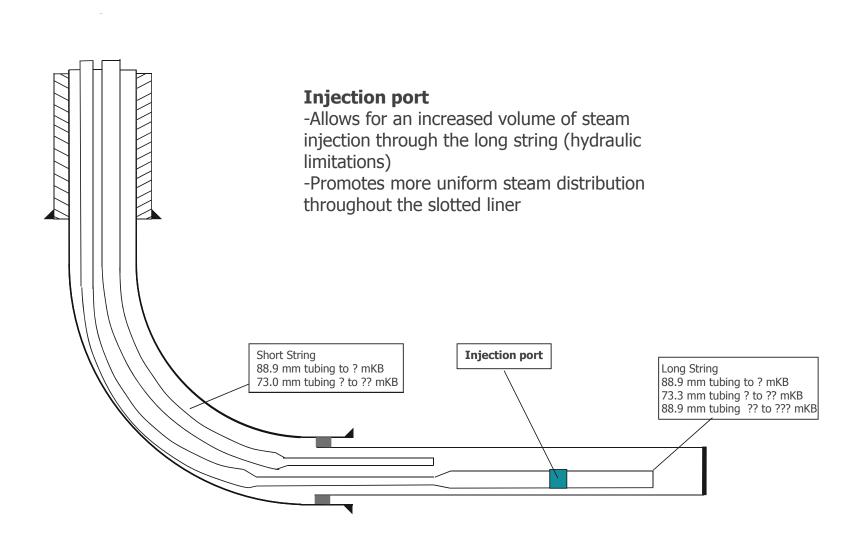
 Connacher does not measure injector well BHT. This is intrepeted from injector reservoir pressure using saturated steam temperature tables.

Producer well BHT Measurement

 Connacher uses instrumentation coil strings with fiber or thermocouples to measure producer well BHT at both Algar and Pod One.

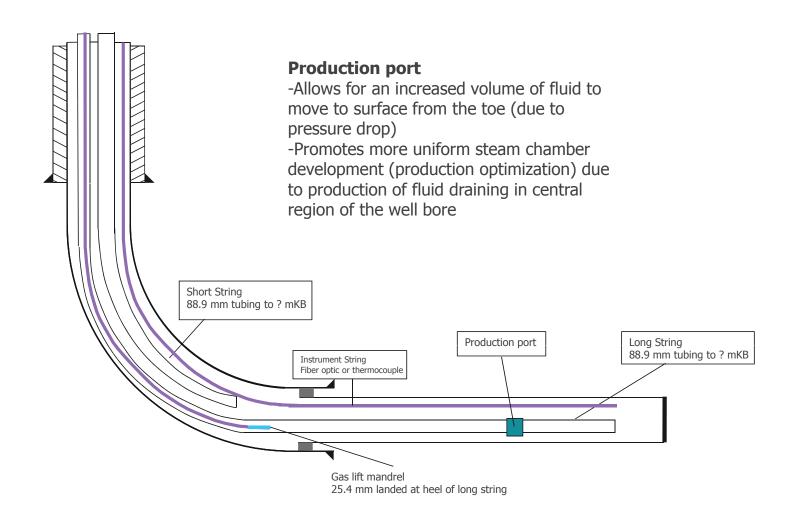
Typical Injector Completion





Typical Producer Gas Lift Completion



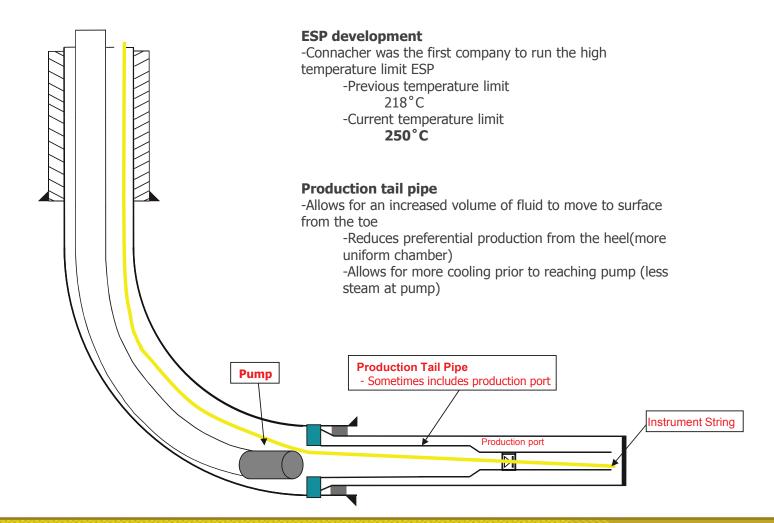


Typical Producer Mechanical Lift



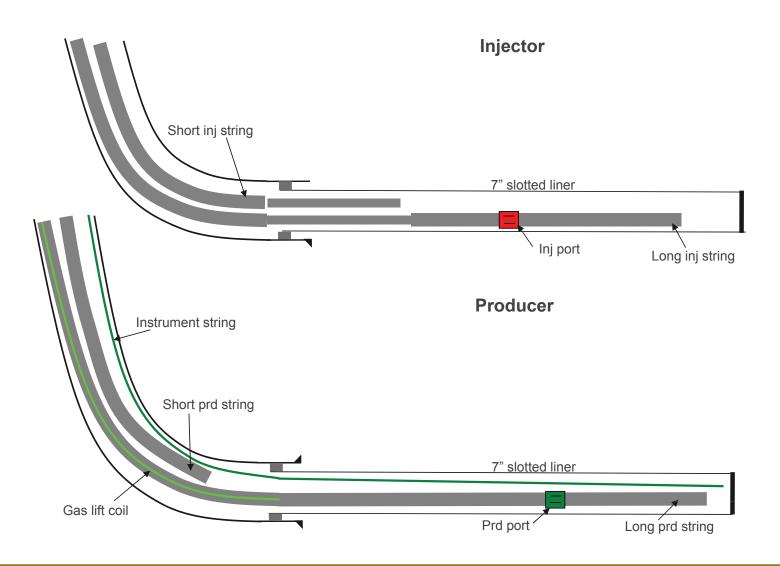
Electronic Submersible Pump

Metal on metal Progressive cavity pump Tubing pump (hydraulic pump jack)



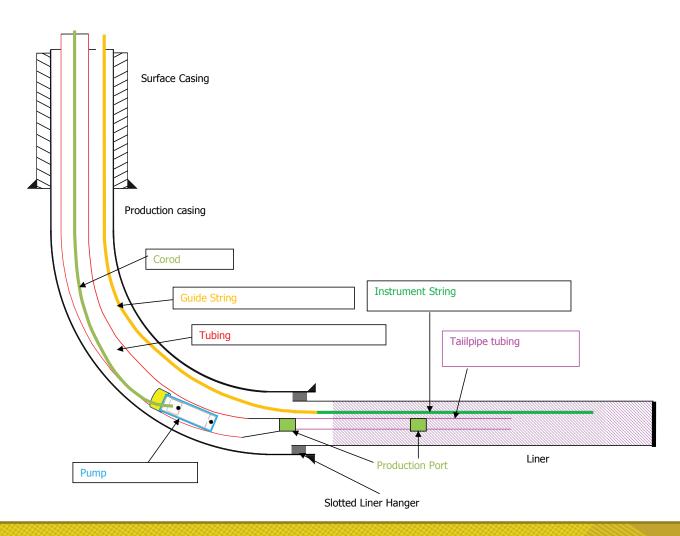
Improved Well Bore Design (Algar)





Typical Infill Well Completion









Artificial Lift Performance - Pod One



Pad	Well	Pump Type	Pump	Install date	Failure date	Run Time (days)	Current
101N	101-01	PCP	1	5/5/2010	12/25/2010	234	
101N	101-01	Rod Pump	2	4/24/2013	5/29/2013	35	
101N	101-01	Rod Pump	3	10/26/2013	TBD	704	Rod Pump
101N	101-02	PCP	1	05/05/10	05/07/10	2	
101N	101-02	РСР	2	5/10/2010	11/5/2010	179	
101N	101-02	Rod Pump	3	4/14/2013	9/9/2013	148	
101N	101-02	Rod Pump	4	9/11/2013	2/12/2014	154	
101N	101-02	Rod Pump	5	2/17/2014	TBD	590	Rod Pump
101N	101-03	РСР	1	08/19/10	09/13/10	25	
101N	101-03	PCP	2	9/18/2010	10/16/2010	28	
101N	101-03	Rod Pump	3	9/26/2011	6/2/2012	250	
101N	101-03	Rod Pump	4	6/7/2012	1/9/2013	216	
101N	101-03	Rod Pump	5	1/15/2013	7/19/2013	185	
101N	101-03	Rod Pump	6	7/25/2013	TBD	797	Rod Pump
101N	101-04	PCP	1	08/11/2010	11/05/2010	86	
101N	101-04	Rod Pump	2	4/16/2013	5/31/2013	45	
101N	101-04	Rod Pump	3	10/27/2013	2/17/2014	113	
101N	101-04	Rod Pump	4	2/20/2014	TBD	587	Rod Pump
101N	101-05	PCP	1	08/06/10	09/08/12	764	
101N	101-05	PCP	2	9/16/2012	7/25/2014	677	
101N	101-05	РСР	3	7/27/2014	8/28/2014	32	
101N	101-05	РСР	4	9/9/2014	TBD	400	PCP

_			
Pad	1	Λ1	N

As steam is removed from this Pad rod pumps are the most practical solution.

Pad	Well	Pump Type	Pump	Install date	Failure date	Run Time (days)	Current
104	104-04	ESP	1	5/11/2014		551	ESP
104	104-06	ESP	1	4/8/2014	9/22/2014	167	
104	104-06	ESP	2	9/27/2014		368	ESP
104	104-05	ESP	1	3/12/2015		202	ESP
104	104-03	ESP	1	11/22/2014		312	ESP

Pads 101S, 102W, 102S & 104

These Pads produce from good quality oil sands reservoir and are a good application of ESP's. The pump history is shown here as an example.

The higher rate wells can accommodate ESP's whereas lower rate wells and infills operate more efficiently with rod pumps.

Pads 101S, 102W and 102S are similar and a detailed history of all the pumps at Great Divide is provide in the additional files accompanying this presentation.

Artificial Lift Performance - Algar



Pad	Well	Pump Type	Pump	Install date	Failure date	Run Time (days)	Current
201	201-03	ESP	1	1/19/2011	5/19/2011	120	
201	201-03	ESP	2	5/23/2011	10/22/2011	152	
201	201-03	ESP	3	10/28/2011	4/26/2012	181	
201	201-03	Rod pump	4	11/3/2013	6/19/2014	228	
201	201-03	Rod pump	5	6/22/2014	8/14/2014	53	
201	201-03	Rod pump	6	8/17/2014	3/1/2015	196	
201	201-03	Pod pump	7	3/7/2015		207	Rod pump
201	201-04	ESP	1	2/14/2011	6/14/2012	486	
201	201-04	ESP	2	6/21/2012	9/25/2013	461	
201	201-04	Rod pump	3	10/8/2013	10/22/2014	378	
201	201-04	Rod pump	4	10/24/2014	5/15/2015	203	
201	201-04	Rod pump	5	5/16/2015		137	Rod pump
201	201-05	ESP	1	1/27/2011	5/8/2011	101	
201	201-05	ESP	2	5/18/2011	5/2/2012	350	
201	201-05	ESP	3	5/5/2012	6/29/2013	420	
201	201-05	Rod pump	4	7/30/2013	5/19/2014	293	
201	201-05	Rod pump	5	5/22/2014	9/27/2014	128	
201	201-05	Rod pump	6	9/30/2014	2/2/2015	125	
201	201-05	Rod pump	7	2/5/2015		249	Rod pump
203	203-01	ESP	1	5/3/2013	12/24/2013	235	Gas lift
203	203-02	ESP	1	5/8/2013	9/5/2014	485	Gas lift
203	203-04	ESP	1	5/14/2013	9/28/2013	137	Gas lift

Algar

Artificial lift at Algar was based on gas lift for the early stages of production with a later move to lower pressure operation with pumps being considered.

The selection of pumps is based on well productivity and Connacher's experience.

ESPs have been used in three wells in Pad 201. These three wells are in, or close to, a limited bottom water zone and the pumps are required to balance pressure and avoid high steam losses.

Recently, and as part of the SAGD+ *test, ESPs were installed in three wells in Pad 203. Results show that SOR was reduced by using ESPs for artificial lift. But, due to reservoir characteristics and economics, these wells were converted back to gas lift.

Gas Migration & Surface Casing Vent Flows



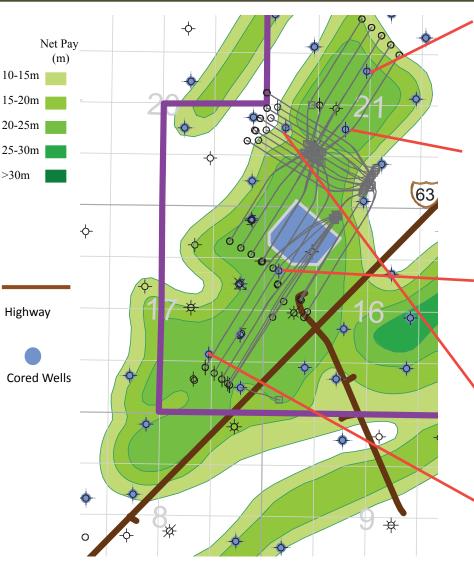
- Surface Casing Vent Flow (SCVF) assemblies were installed on remaining wells at Pads 101 and 102 in October 2015.
- SCVF tests were conducted on all injectors and producers at Pod One and Algar in October,
 2015. Results will be reported to the AER through DDS.
- Surface Casing Vent Flow assemblies were installed on new infill wells at Pad 101S.
- A summary table of all historical SCVF results is provided as an additional file to this report.
- Connacher believes that it is currently compliant with all SCVF requirements at the Great Divide Project.





Pod One Observation Wells





100/11-21-82-12W4, Operational April 2011

- Monitor North Pad Performance (47m from Well Pair 101-04)
- Five temperature and five pressure measurements all operational
- Temperature readings suspect all at original reservoir temperature ~14 °C
- Pressure gauges operational
- Continue collecting data

100/06-21-082-12W4, Operational Dec 2007

- Purpose was to measure rise of steam and to determine if steam moved into any overlying gas caps (39 m from Well Pair 101-05)
- Operational but readings suspect
- Maximum temperature 20 °C.
- Pressure gauges not operational
- Continue collecting data

111/12-16-82-12W4, Operational Mar 2010

- Provided observations on effects of low pressure operations (40 m from Well Pair 101S-P10)
- Five temperature measurements all operational. 2 of 5 Pressure gauges not operational
- Continue collecting data

111/05-21-82-12W4, Operational Mar 2012

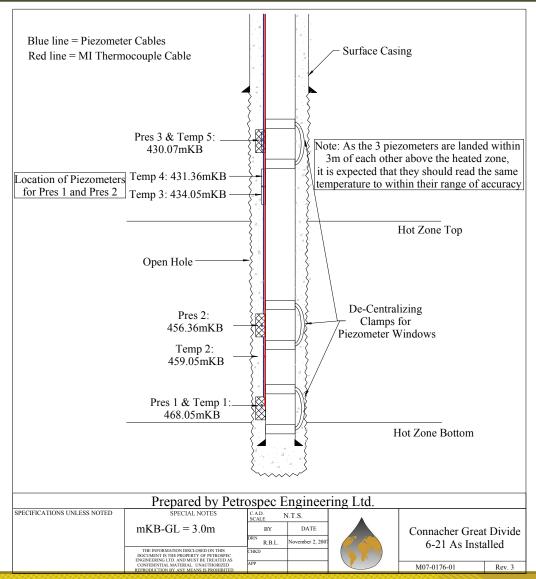
- Drilled to acquire information on temperature between well pairs for future infill wells (40m from Well Pair 102-03)
- Five temperature measurements operational. Lower pressure gauge not operational
- Continue collecting data

100/07-17-82-12W4, Operational Mar 2012

- Drilled to acquire information on gas cap repressurizing (33m from Well Pair 104-P03)
- Five temperature and five pressure measurements operational
- Continue collecting data

Pod One - Typical Observations Well

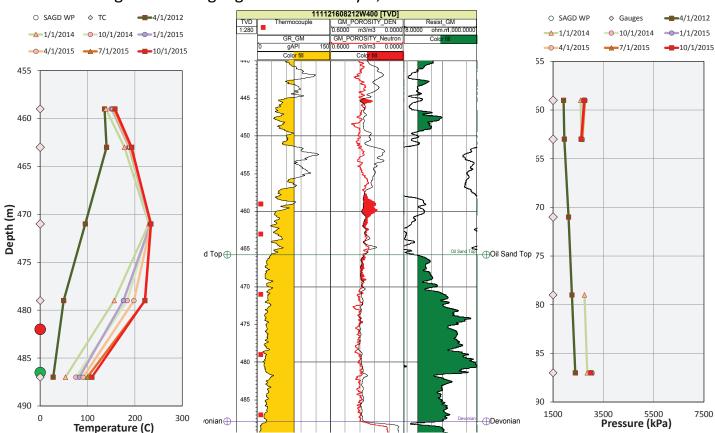


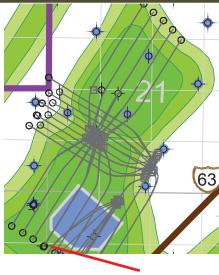


Pod One Obs Well - 111/12-16-82-12 W4



Chamber appears to be fully developed. Steam is suspected to be leaking to gas cap and lean zone. Temperature readings provide support for gas cap repressurization. No valid pressure readings for 2 of 5 gauges after January 1, 2013.

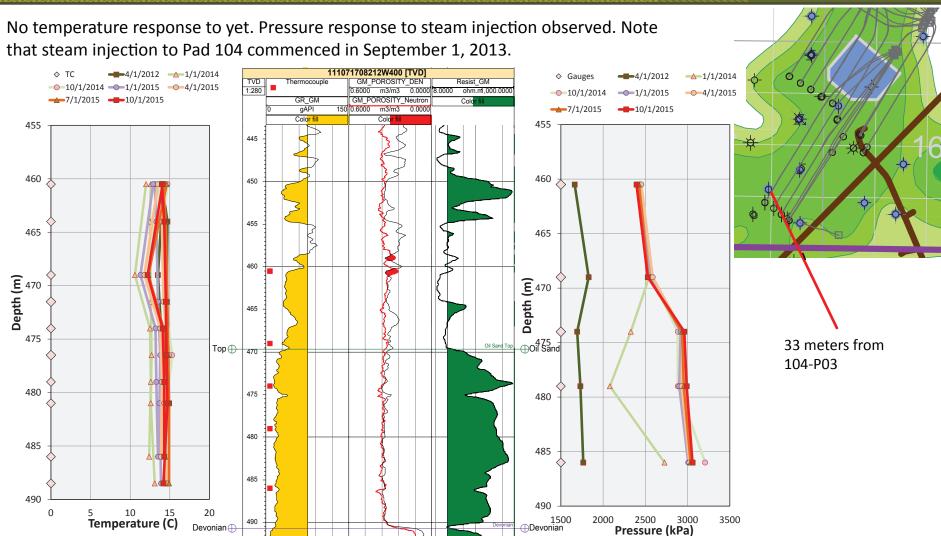




40 meters from 101S-P10

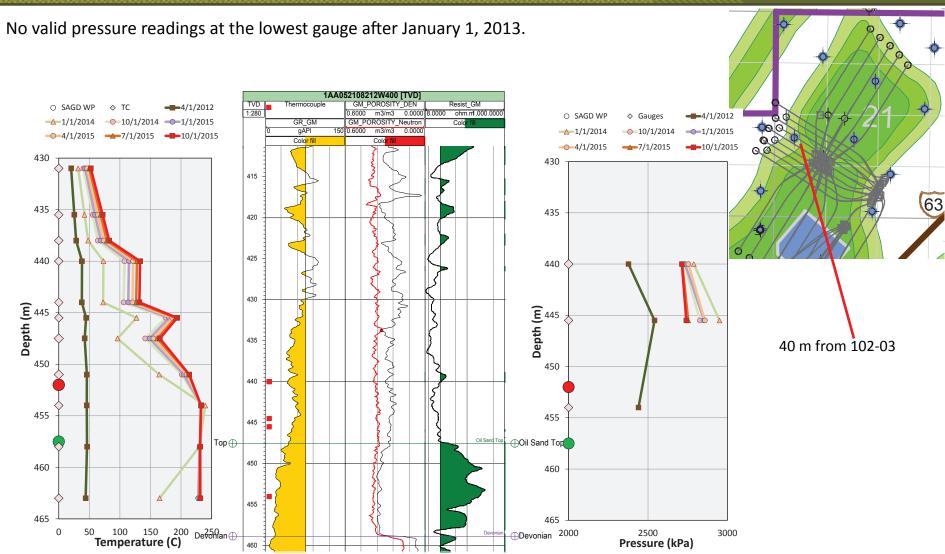
Pod One Obs Well - 111/07-17-82-12 W4





Pod One Obs Well - 111/05-21-82-12 W4

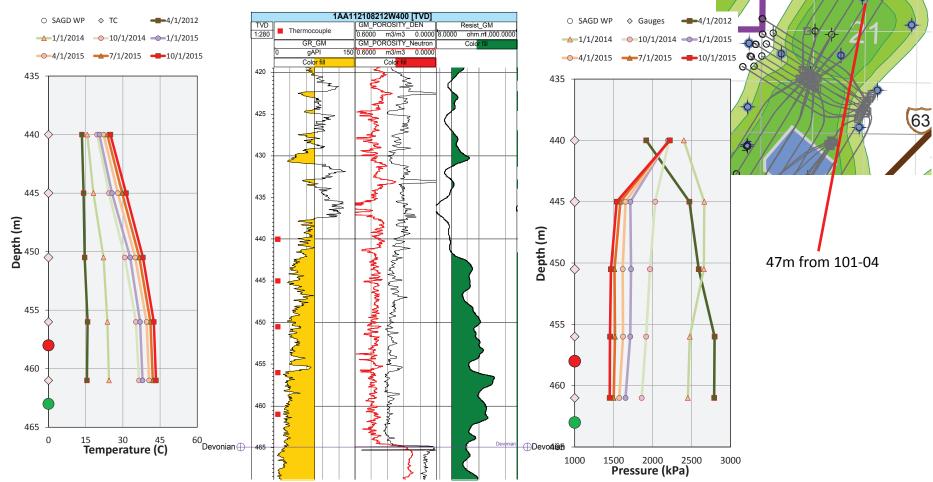




Pod One Obs Well - 100/11-21-82-12 W4



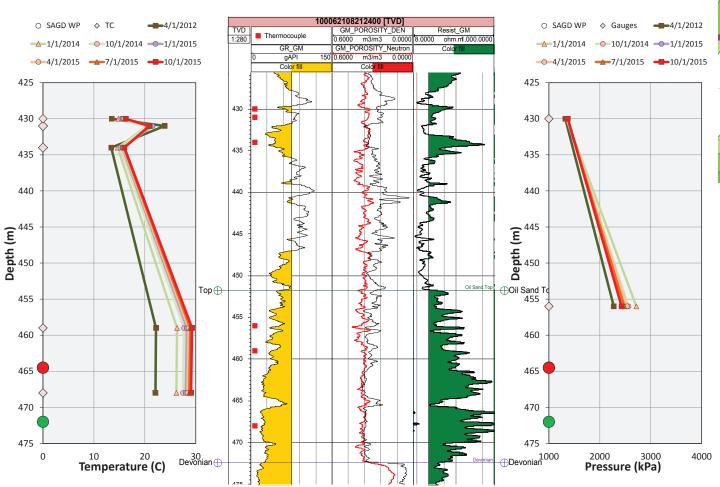
Temperature readings confirm that steam distribution in Pad 101N was a challenge. Note that Pad 101N is on blowdown. Temperature and pressure readings portray a relatively fast response to blowdown.

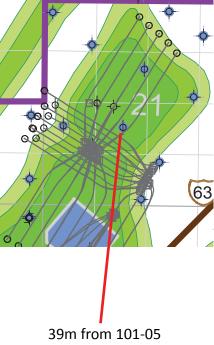


Pod One Obs Well - 100/06-21-82-12 W4



Pressure and Temperature readings are suspect.





Algar Observations Wells







100/04-19-082-11W4M Operational February 2011

- 6m from Well Pair 203-04
- Monitors Pad 202 performance
- Five temperature measurements operational
- Five pressure gauges are suspect

100/01-24-082-12W4M Operational February 2011

- 20m from Well Pair 203-06
- Five thermocouples operational
- Four pressure gauges operational

100/15-13-082-12W4M Operational February 2011

- 8m from Well Pair 201-04
- Five thermocouples operational
- One pressure gauge operational

100/09-13-082-12W4M Operational February 2011

- 37m from Well Pair 202-04
- Five thermocouples operational

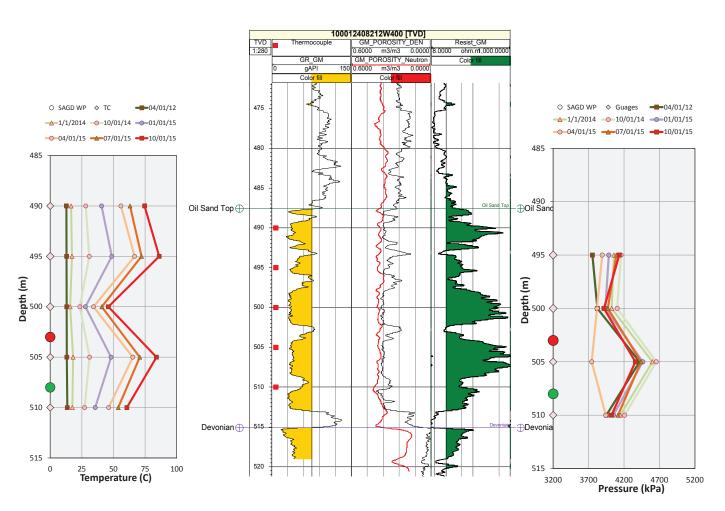
111/16-13-82-12W4W4 Operational March 2012

- 48m from Well Pair 203-05
- Five thermocouples operational
- Five pressure gauges operational

Algar Obs Well - 100/01-24-82-12 W4



Temperature readings at 490 m depth suggest that steam is moving to higher IHS zones. This suggests that the IHS zone are discontinuous at this location.

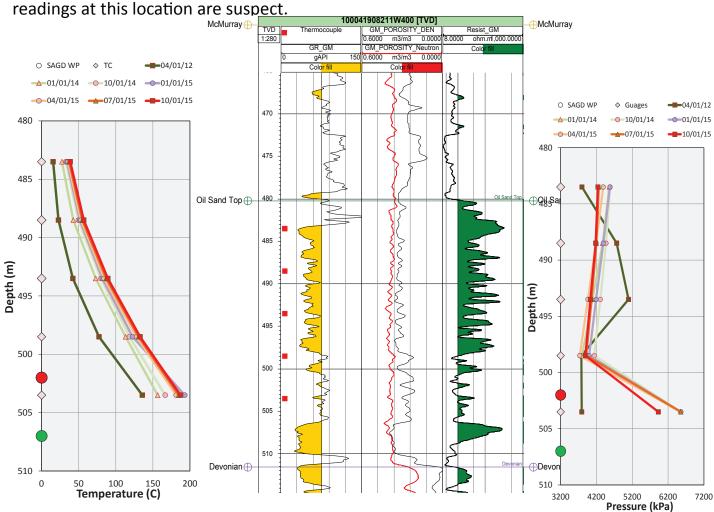




Algar Obs Well - 100/04-19-82-11 W4



Temperature readings show temperature development in intense IHS zones. Pressure readings at this location are suspect



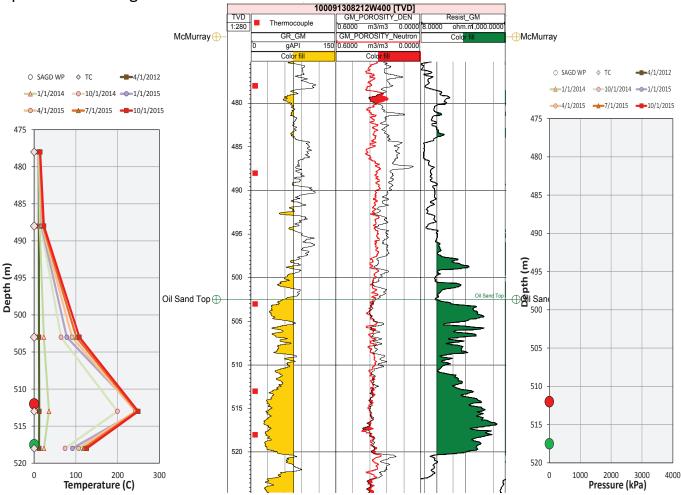


Algar Obs Well - 100/09-13-82-12 W4



Temperature readings supports the development of infill wells at this location. No

pressure readings available.

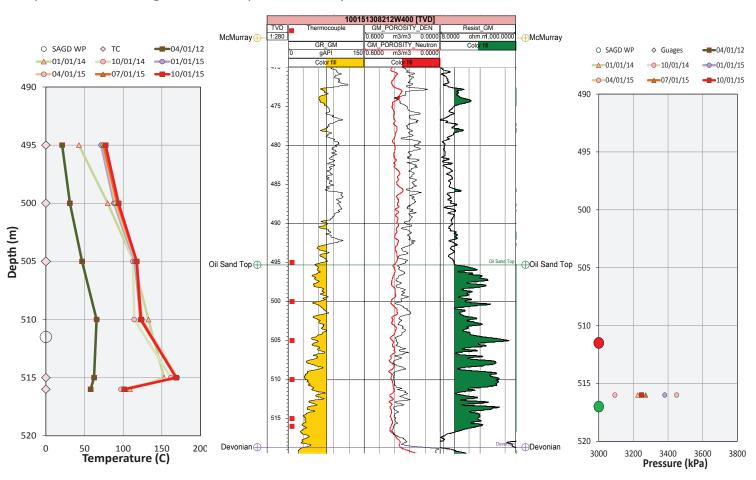




Algar Obs Well - 100/15-13-82-12 W4



Temperature readings show temperature response in IHS zone.

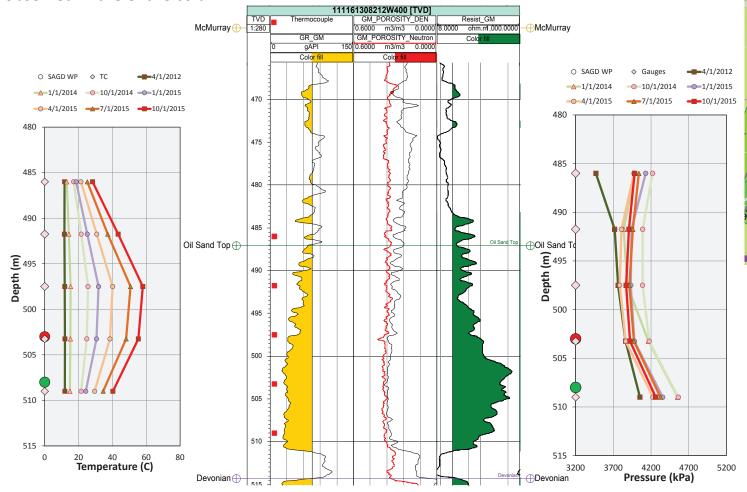




Algar Obs Well - 111/16-13-82-12 W4



Temperature readings shows temperature development in the IHS zone. It is expected that there will be more temperature response at lower depths in the future. Pressure response is observed in the entire column.





Notes on Obs Well equipment failure



Pod One

12-16-82-12W4

- Thermocouples at all measurement depths are operating properly
- Piezometers at depths of 471m, and 478m are not operating due to gauge failure. There are no plans to replace the equipment

5-12-82-12W4

- Thermocouples at all depths are operating properly
- Piezometer located at 445.5 and 454m are not operating due to gauge failure. There are no plans to replace the equipment

6-21-82-12W4

- Thermocouples at all depths are operating properly
- All piezometers in this well are not operational. There are no plans to replace the equipment

Algar

9-13-82-12W4

- Thermocouples at all depths are operating properly
- All piezometers in this well are not operational. There are no plans to replace the equipment

15-13-82-12W4

- Thermocouples at all the depths are operating properly
- Piezometer located at 516m is the only pressure gauge operating properly. There are no plans to replace the equipment

Pod One & Algar Ground Movement

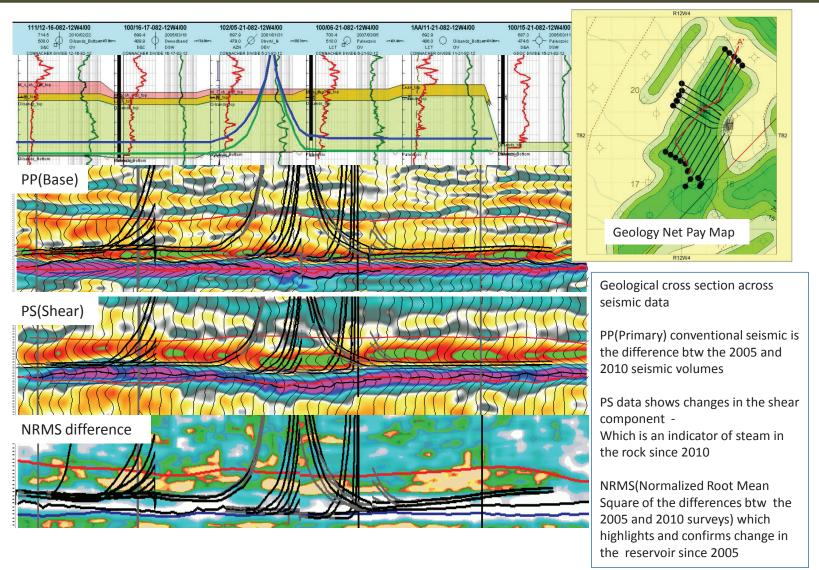




In 2015, 13 km of 'old' Highway 63 (now S/B lanes) resurveyed in 2015 with +/- 10 cm of vertical movement (natural movement) observed at various points. Also a baseline survey was conducted on the 'new' N/B lanes of Highway 63. Within Pod One and Algar 30 monitoring and 5 control points were resurveyed in 2015. The maximum vertical deformation was 3cm (at 5 locations), all others were < 2cm. Connacher added 3 new monitoring points in 2015. All lanes of Highway 63, 33 monitoring points, and 5 control points will be resurveyed in 2016.

Pod One 4D Seismic



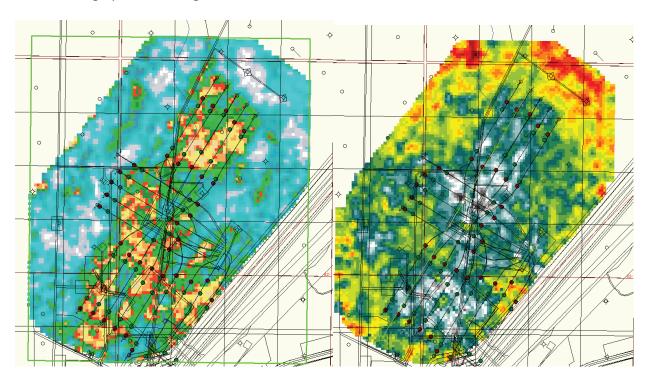


Pod One 4D Seismic (2)



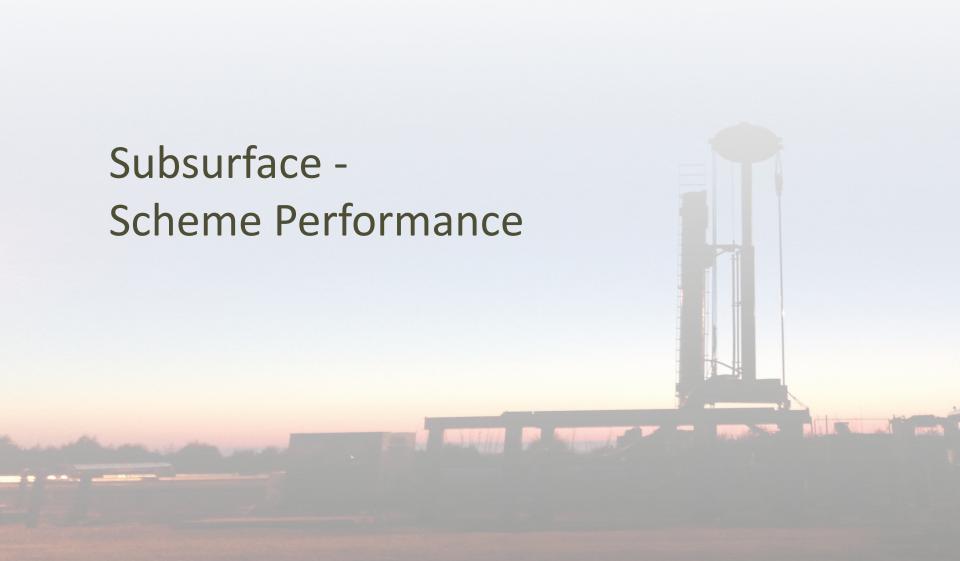
NRMS - normalized root mean square represents the % change in the seismic signal since steaming operations began

Shear Data - should represent the extent of the steam chamber



The NRMS represents the percent change in the reservoir since steaming operations commenced in 2007. This roughly corresponds to produced bitumen and should represent the various steam chambers. The shear data is not affected by steam, gas or bitumen heated above 80 C, as this acts like a liquid. The resulting map should show the current extend of the steam chambers. The two maps should be similar and are not, therefore the results of the 4D seismic are inconclusive. Possible reasons for this include plant and highway noise, and errors resulting from using different geophones at different locations in the two surveys.





Great Divide Well Layout





Pod One

- 23 Well Pairs (101N, 101S, 102S, 102W and 104)
- 13 Infills
- SAGD well pairs in 101N, 101S, 102S and 102W were drilled at 100m spacing
- SAGD well pairs in 104 were drilled at 80m spacing
- All infills (except 102INF06 @35m) were drilled at 50m spacing between the SAGD producers

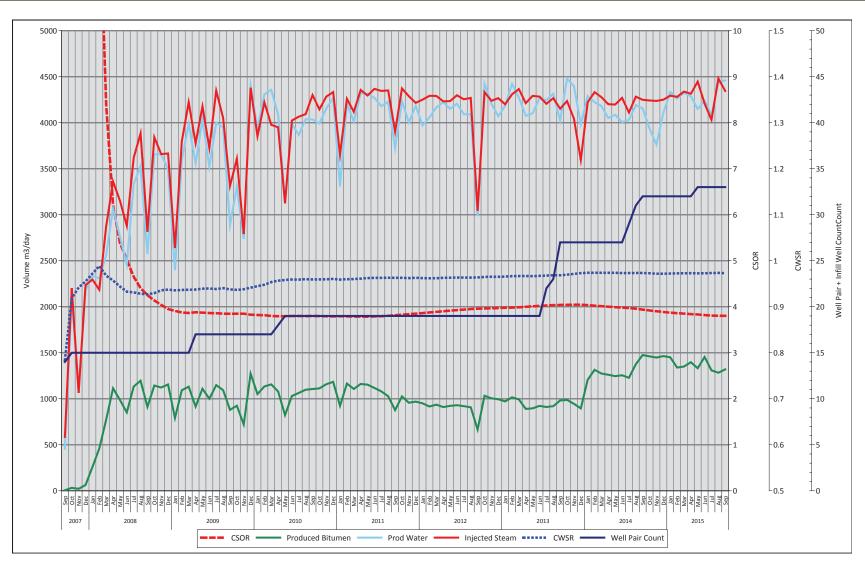
Algar

- 18 Well Pairs (201, 202 and 203)
- All SAGD well pairs except 202-01R were drilled at 100m spacing
- 202-01R was drilled 35m from 201-01 and 65m from 202-02 well pair

Note: In order to accommodate similar production and injection start times well pair 11S (shown) was included with Pad 102S for performance plots and resource calculations.

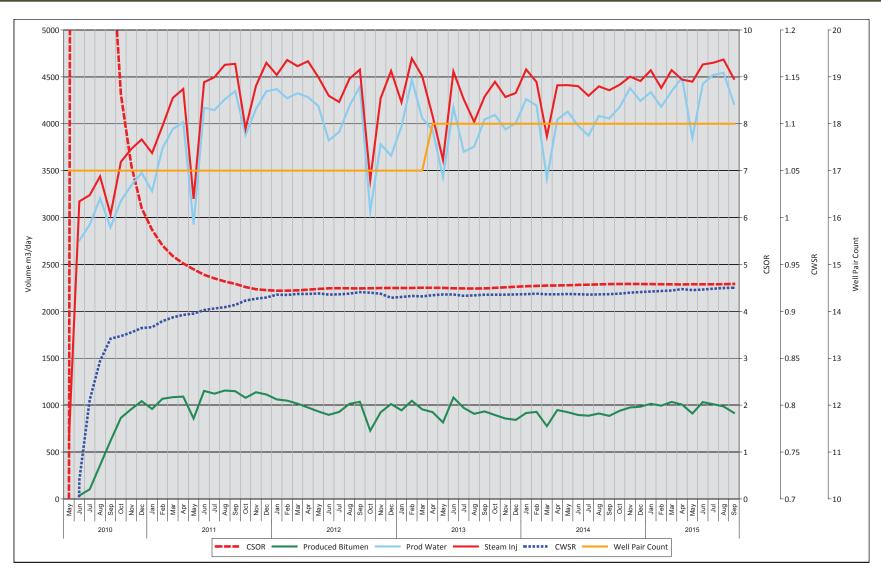
Pod One Performance





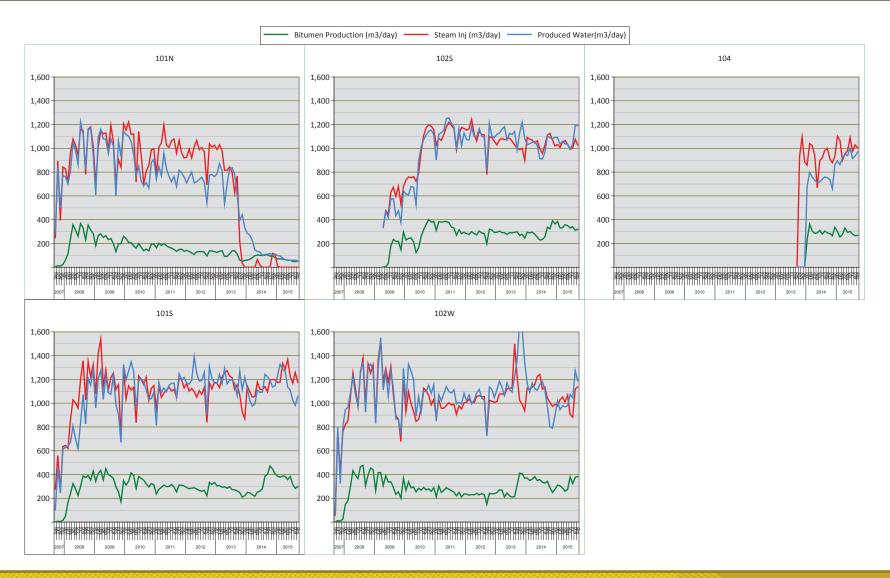
Algar Performance





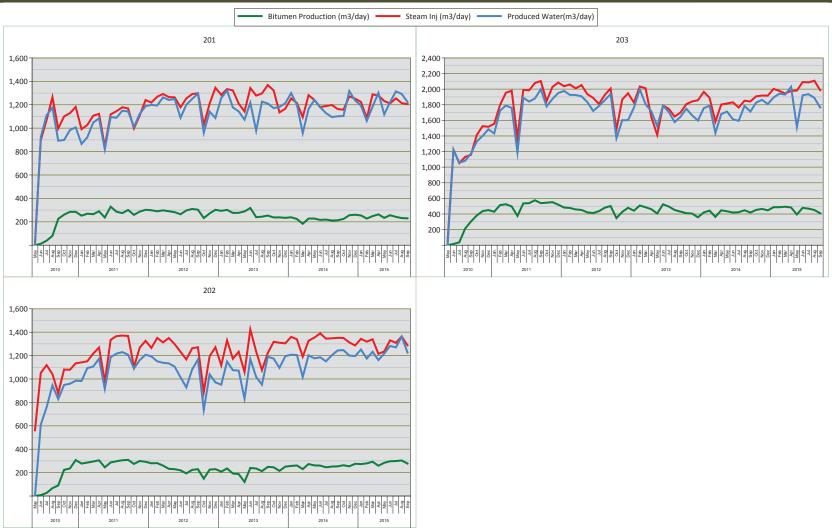
Pod One - Pad Production & Injection





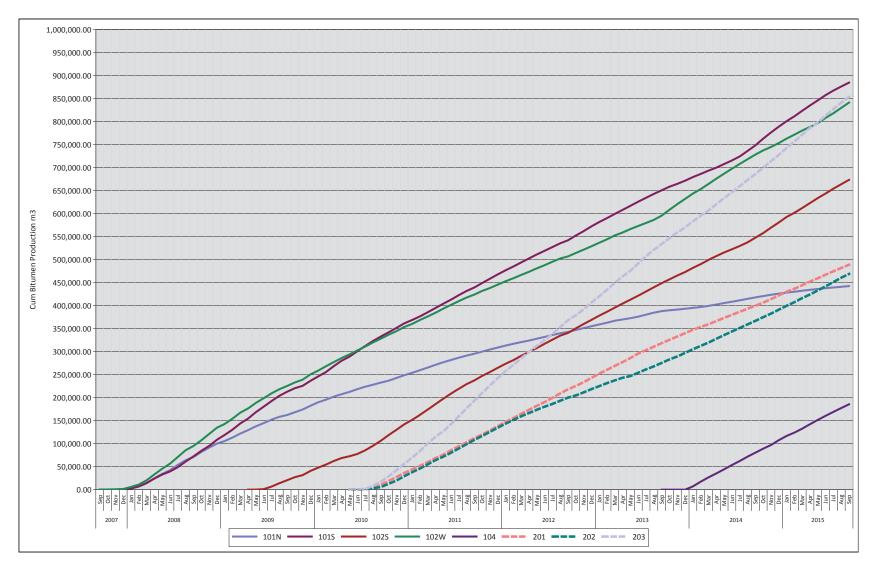
Algar - Pad Production and Injection





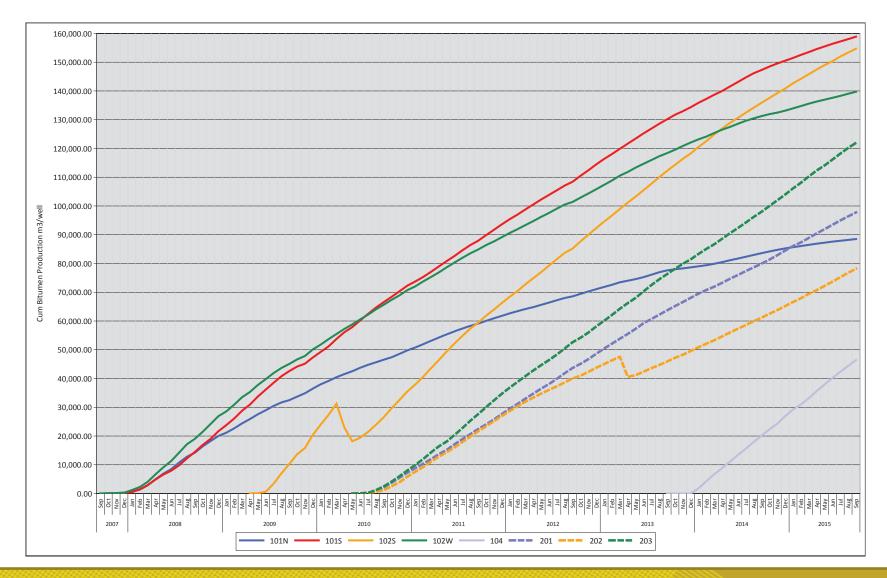
Great Divide Performance - Cumulative Production by Pad





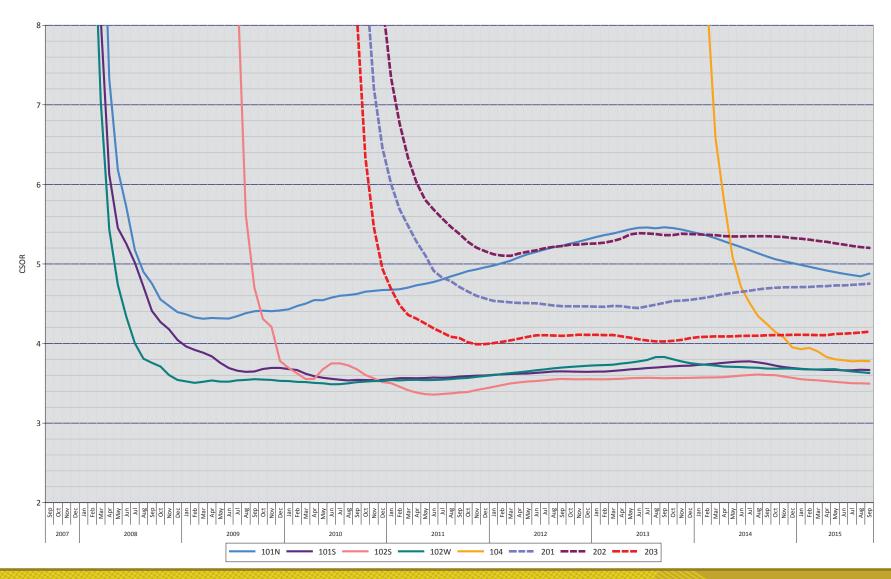
Great Divide Performance -Cumulative Production per Well by Pad





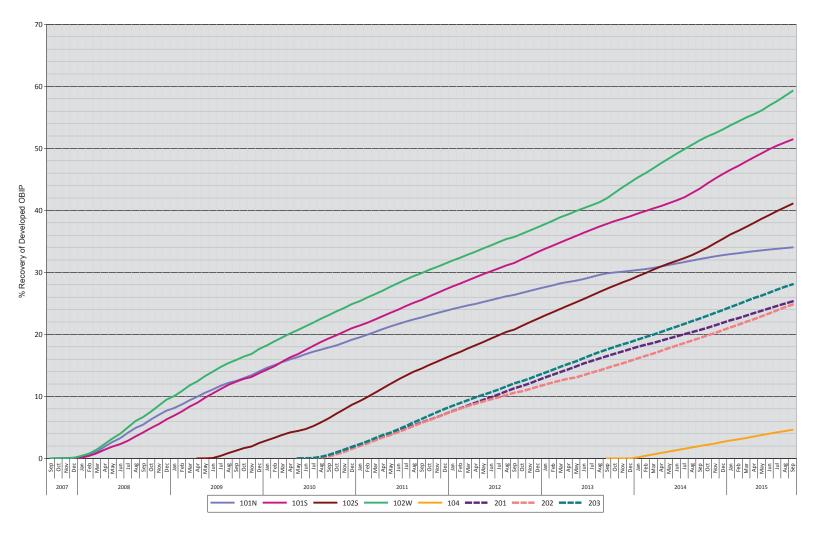
Pod One Performance - CSOR by Pad





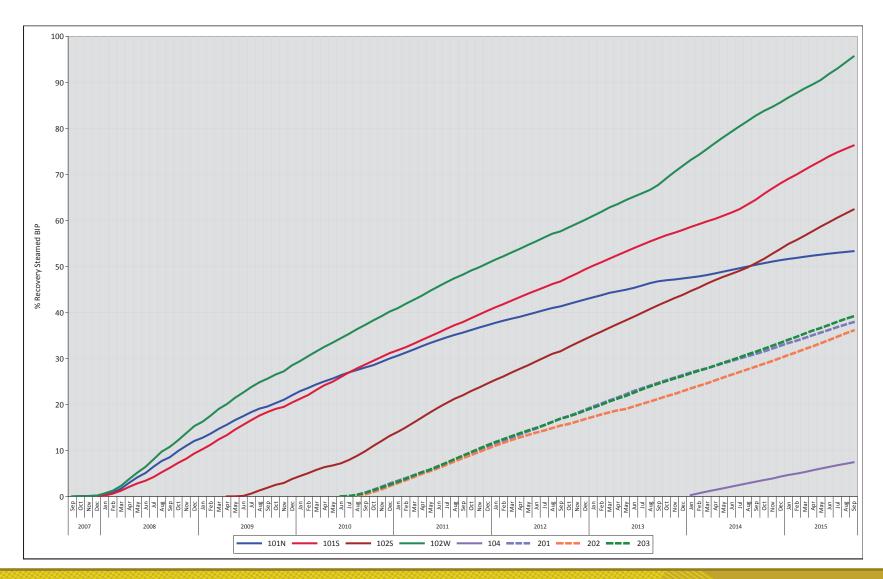
Great Divide Performance - Recovery Developed OBIP by Pad





Great Divide Performance - Recovery Steamed OBIP by Pad





Pod One Performance - Well Summary



Well Pad	Well Pair	Date	Months On	Cum Oil m3	Cum Steam m3	Oil Rate (m3/day)	CSOR	Lift	Comments
101N	101-01	Sep-2015	97	89683	447647	10	5	Rod Pump	North Pad, Channel Edge, Blowdown
101N	101-02	Sep-2015	97	78190	441630	7	5.6	Rod Pump	North Pad, Channel Edge, Blowdown
101N	101-03	Sep-2015	96	65488	341324	3	5.2	Rod Pump	North Pad, Channel Edge, Blowdown
101N	101-04	Sep-2015	97	106392	477936	9	4.5	Rod Pump	North Pad, Channel Edge, Blowdown
101N	101-05	Sep-2015	97	99388	425841	10	4.3	Metal PCP	North Pad, Channel Edge, Blowdown
101S	101-06	Sep-2015	97	117453	523565	20	4.5	Rod Pump	Average Well, Channel Edge
101S	101-07	Sep-2015	97	109293	551183	18	5	Rod Pump	Average Well, Channel Edge
101S	101-08	Sep-2015	97	234555	823450	22	3.5	ESP	Good Well in Good Pay
101S	101-09	Sep-2015	97	153195	668662	30	4.4	ESP	Good Well in Good Pay
101S	101-10	Sep-2015	97	178664	688099	42	3.9	ESP	Good Well in Good Pay
101S	101-11	Sep-2015	78	187755	743311	42	4	ESP	Good Well in Good Pay
101S	101-INF7	Sep-2015	1	-	3108	41	-	Rod Pump	Too early
101S	101-INF8	Sep-2015	13	30862	0	70	-	Rod Pump	Good well in Good Pay
101S	101-INF9	Sep-2015	15	33129	937	66	-	Rod Pump	Good Well in Good Pay
101S	101-INF10	Sep-2015	15	26656	2328	63	-	Rod Pump	Good Well in Good Pay
101S	101-INF11	Sep-2015	14	30172	325	36	-	Rod Pump	Good Well in Good Pay
101S	101-INF12	Sep-2015	14	24362	3769	92	-	Rod Pump	Good Well in Good Pay

Pod One Performance Well Summary (2)



Well Pad	Well Pair	Date	Months On	Cum Oil m3	Cum Steam m3	Oil Rate (m3/day)	CSOR	Lift	Comments
102W	102-01	Sep-2015	97	142638	599987	41	4.2	Rod Pump	Average Well, Crosses Channel
102W	102-02	Sep-2015	97	128147	573358	32	4.5	Rod Pump	Average Well, Crosses Channel
102W	102-03	Sep-2015	97	128078	582301	20	4.5	Rod Pump	Average Well, Crosses Channel
102W	102-04	Sep-2015	97	147891	626261	20	4.2	ESP	Average Well, Crosses Channel
102W	102-05	Sep-2015	97	153652	642893	20	4.2	ESP	Average Well, Crosses Channel
102S	102-12	Sep-2015	78	221178	740317	64	3.3	ESP	Good Well in Good Pay
102S	102-13	Sep-2015	66	97358	399984	33	4.1	ESP	Average Well, Channel Edge
102S	102-14	Sep-2015	65	111653	464327	32	4.2	ESP	Average Well, Channel Edge
102W	102-INF02	Sep-2015	26	23016	3184	58	-	Rod Pump	Average Well, Crosses Channel
102W	102-INF03	Sep-2015	27	36331	5402	60	-	Rod Pump	Average Well, Crosses Channel
102W	102-INF04	Sep-2015	27	37178	7286	34	-	Rod Pump	Average Well, Crosses Channel
102W	102-INF05	Sep-2015	27	32188	5534	29	-	Rod Pump	Average Well, Crosses Channel
102W	102-INF06	Sep-2015	5	13152	1174	66	-		Good Well in Good Pay
104S	104-03	Sep-2015	25	63067	206975	84	3.3	Gas Lift	Good Well, thief zone impacts
104S	104-04	Sep-2015	25	43905	163675	77	3.7	ESP	Good Well, thief zone impacts
104S	104-05	Sep-2015	25	47755	197410	65	4.1	Gas Lift	Good Well, thief zone impacts
104S	104-06	Sep-2015	25	30303	136775	41	4.5	ESP	Average Well, thief zone impacts

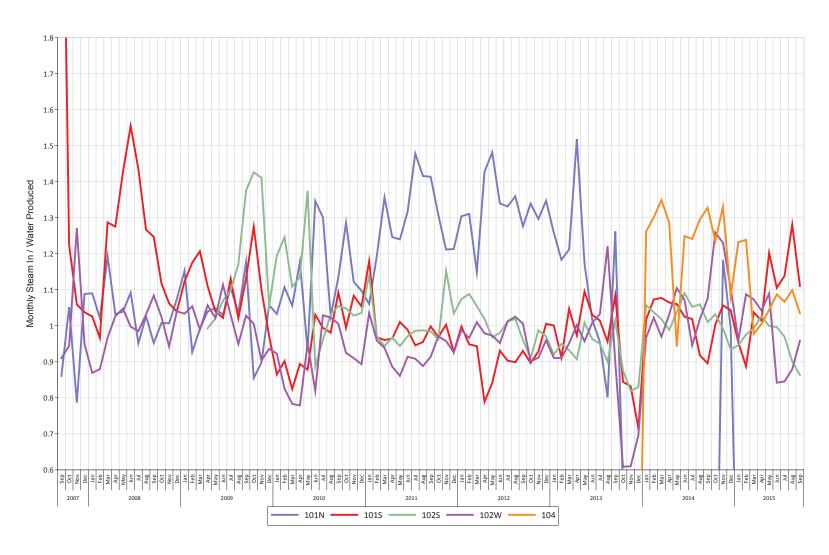
Algar Performance - Well Summary



		1							
Well	Well Pair	Date	Months	Cum Oil m3	Cum Steam	Oil Rate	CSOR	Lift	Comments
Pad			On		m3	(m3/day)			
201	201-01	Sep-2015	65	159905	679910	77	4.3	Gas Lift	Good Well, Good Pay, BW
201	201-02	Sep-2015	65	149931	623668	87	4.2	Gas Lift	Good Well, Good Pay, BW
201	201-03	Sep-2015	65	57890	330289	40	5.7	Rod Pump	Intermittent, Sand Issues, BW
201	201-04	Sep-2015	65	64554	340290	27	5.3	Rod Pump	BW / Evaluating Pump Strategy
201	201-05	Sep-2015	65	60928	356761	33	5.9	Rod Pump	BW / Evaluating Pump Strategy
202	202-01	Sep-2015	65	49978	190978	32	3.8	Gas Lift	Edge Well
202	202-01-1	Sep-2015	65	50225	268798	82	5.4	Gas Lift	Good Well in Good Pay
202	202-02	Sep-2015	65	120359	539972	74	4.5	Gas Lift	Good Well in Good Pay
202	202-03	Sep-2015	65	78582	431948	41	5.5	Gas Lift	Average Well, BW
202	202-04	Sep-2015	65	71684	413017	53	5.8	Gas Lift	Average well, BW
202	202-05	Sep-2015	65	104204	558219	51	5.4	Gas Lift	Good Well in Good Pay
203	203-01	Sep-2015	65	131619	472835	80	3.6	Gas Lift	Average Well,Good Pay, Edge
203	203-02	Sep-2015	65	139099	495362	80	3.6	Gas Lift	Good Well in Good Pay
203	203-03	Sep-2015	65	122288	530140	56	4.3	Gas Lift	Good Well in Good Pay
203	203-04	Sep-2015	65	131352	548789	80	4.2	Gas Lift	Good Well in Good Pay
203	203-05	Sep-2015	65	159908	637594	70	4.0	Gas Lift	Good Well in Good Pay
203	203-06	Sep-2015	65	108667	479477	70	4.4	Gas Lift	Average Well, Near Edge
203	203-07	Sep-2015	65	69930	394707	45	5.6	Gas Lift	Edge Well, Delayed Start Up

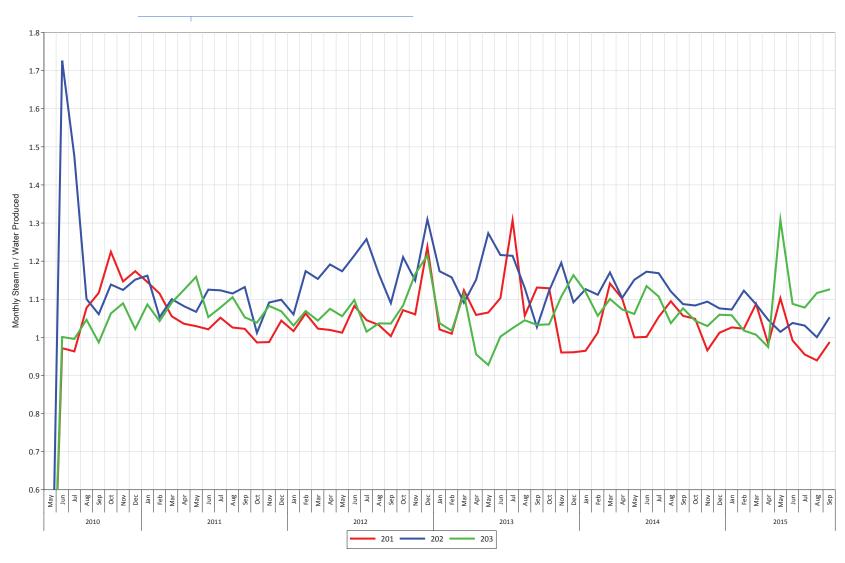
Pod One - Water Balance Cumulative Steam In / Water Produced





Algar - Water Balance Cumulative Steam In / Water Produced





Pod One -Recoverable Bitumen By Pad





Pads	Area (ha)	Avg Porosity (%)	Avg Oil Sat (%)	Avg Net Pay (m)	Pad OBIP (e³m³)	Est Pad Rec (%)	Est Pad Rec (e ³ m ³)	To date Pad Rec (e ³ m ³⁾	Recovery to Sept 2015 (%)
101N	29.6	33	74	18.0	1,300	32	416	442	34
101S	32.6	33	80	20.0	1,720	55	950	885	51
102W	31.6	33	80	17.0	1,420	50	710	841	59
102S	32.7	33	80	19.0	1,640	55	900	674	55
104	70.9	33	80	21.5	4,020	55	2,210	186	8

Notes:

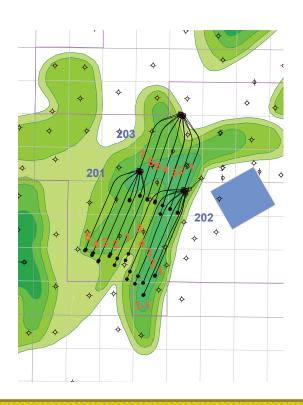
- 1. Pad 101N is in blowdown and an additional 2% recovery expected.
- 2. Additional of estimated infill recoveries of approximately 8% for Pads 101S, 102W, 102S, and 104.
- 3. Estimated Pad Recovery is based on the basic SAGD process.
- 4. Pad 101N injectors were plugged back approximately 1/3 back from well toes.
- 5. Initial Pad recoveries are proving to be on the conservative side.

Algar -

Recoverable Bitumen by Pad



Pads	Area (ha)	Avg Porosity (%)	Avg Oil Sat (%)	Avg Net Pay (m)	Pad OBIP (e³m³)	Est Pad Rec (%)	Est Pad Rec (e³m³)	To date Pad Rec (e ³ m ³⁾	Recovery to Sept 2015 (%)
201	47.1	33	75	19	1,930	55	1,060	489	25.3
202	45.6	33	75	18	1,890	55	1,100	469	24.8
203	56.7	33	75	22	3,040	55	1,670	854	28.1



Notes:

- Pad 203 has completed SAGD+ on a trial basis.
 Reserves will be adjusted when the commercial project begins. An additional recovery of 10% of the OBIP is estimated.
- 2. Estimated Pad Recovery is based on the basic SAGD process.



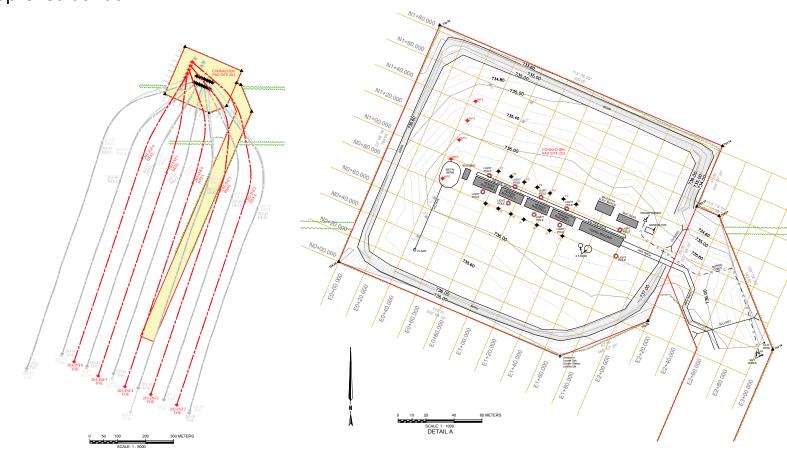


Algar - Pad 203 Infills



 Commercial Scheme Approval 10587Q

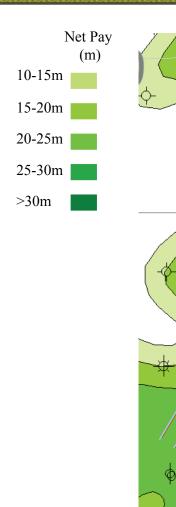
5 Infills Approved at Pad 203

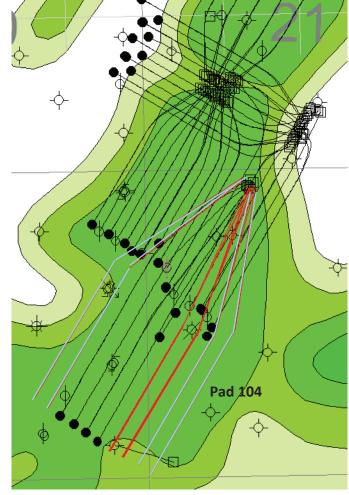


Pod One - Pad 104 Well Pairs



- 10 Well Pair Approved for Pad 104 (Approval 10587H)
- Currently there are 4 existing Well Pairs at Pad 104





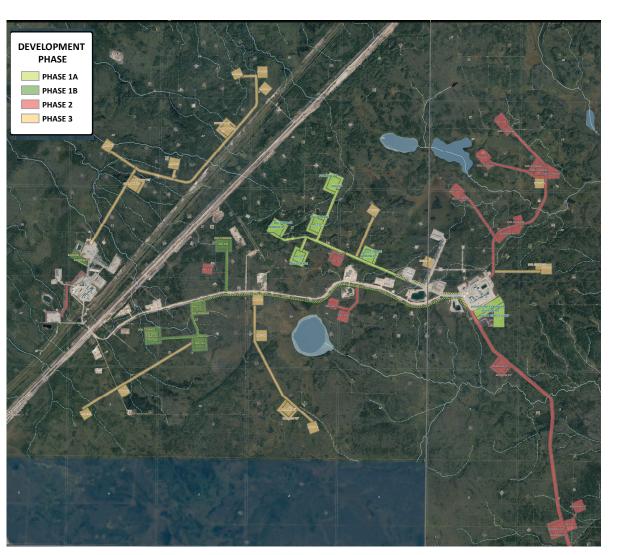
Approved

Approved

Existing

Great Divide SAGD Expansion Project





- EIA Deemed Complete
- Commercial Scheme Approval Received September, 2012
- EPEA Approval Amendment Received December, 2013
- Approved for expansion to 44,000 bbl/day





Pod One Plant





Algar Plant





Pod One Facilities



Key Points

Design Capacity ~ 1,600 m³/day bitumen

Steam Generation: Drum boilers

Operating pressure 6,300 kPa

Deliver 4,300 m³/day steam @ 98% + Quality

Treating: Diluent addition

Water Recycle: IGF, WS Filter, Two vertical tube falling film evaporator towers

Waste Water: Waste water shipped to Algar 2nd Stage Evaporators

Source water: 3 operating source water wells in the Lower Grand Rapids formation, 1 other source water well approved

Algar Facilities



Key Points

Design Capacity ~ 1,600 m³/day bitumen

Steam Generation: Drum boilers

Operating pressure 6,700 kPa

Deliver 4,800 m³/day steam @ 98% + Quality

Treating: Diluent addition

Water Recycle: IGF, WS Filter, Two vertical tube falling film evaporator towers

Waste Water: All water shipped from facility to approved disposal sites

Source water: 3 operating source water wells in the Lower Grand Rapids formation, 1

other source water well approved

Great Divide Plant Modifications



Pod One

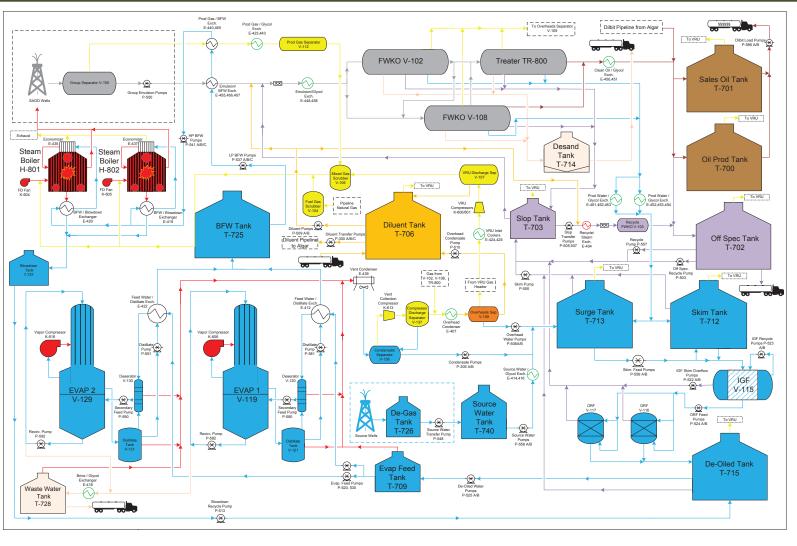
- Installed nozzles on surge tank for online cleaning
- Replaced VRU discharge carbon steel piping with stainless steal piping to eliminate leaks and corrosion potential
- Extended ladder and cage on T-703 to eliminate safety/hazard potential
- Upgraded flow meter on EDTA injection skid, adding the ability to accurately control the feed rate of EDTA to the evaporators and save chemical
- Decomission and remove utility steam section on Pad 101
- Added an extra inlet emulsion/glycol heat exchanger

Algar

- Boiler maintenance
- Upgraded CoGen fuel gas coriolis meter FT-96604 to a full diagnostic model to allow for MARP verification
- Extended the vent piping of the CoGen's BFW to grade to allow for easier access
- Added caustic line from upstream fo FCV-51607 to upstream of FCV-12908, allowing operations staff to clean wasting line periodically
- Decomissioned SAGD+® trial equipment from Pad 203
- Started construction on SAGD+® commercial project.

Pod One Process Schematic

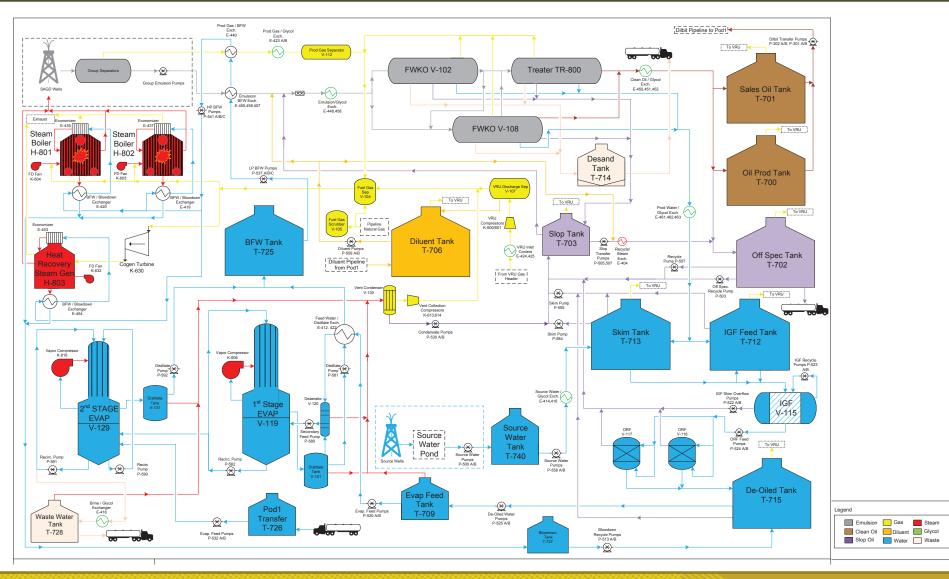






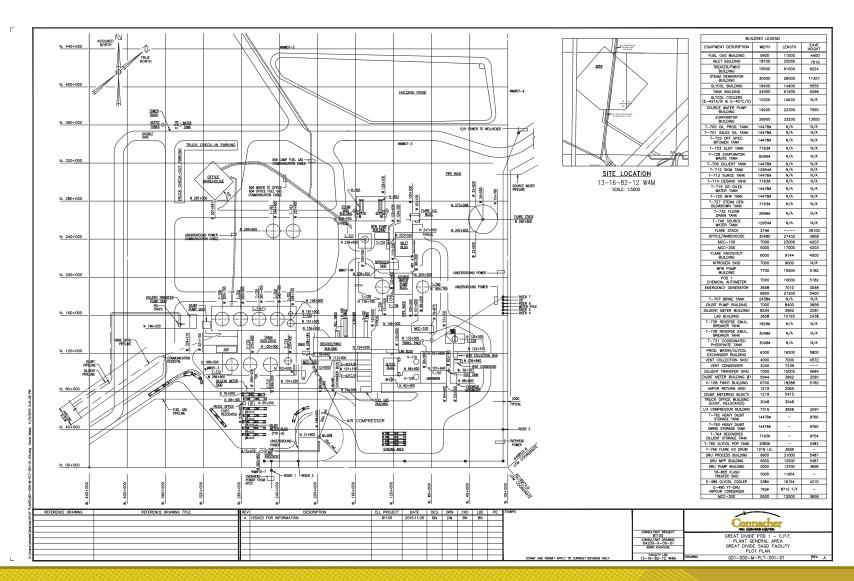
Algar Process Schematic





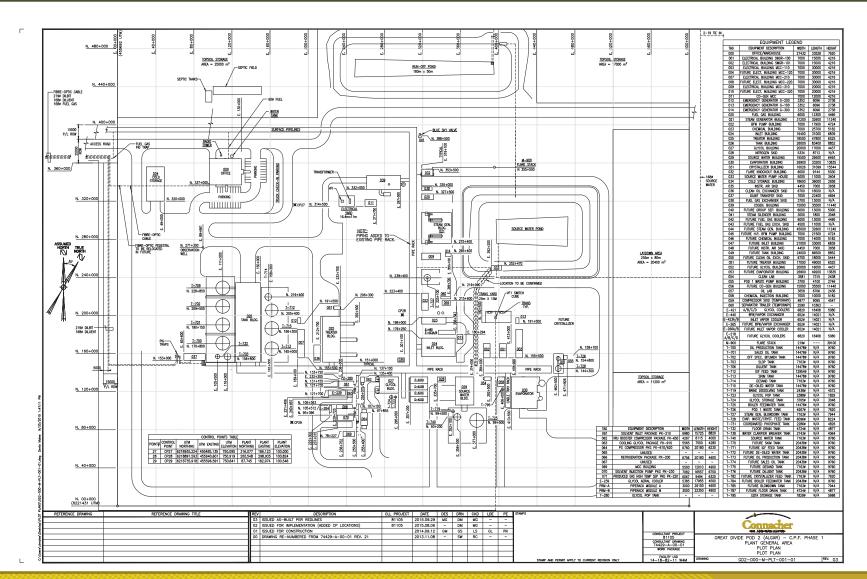
Pod One Plant Layout





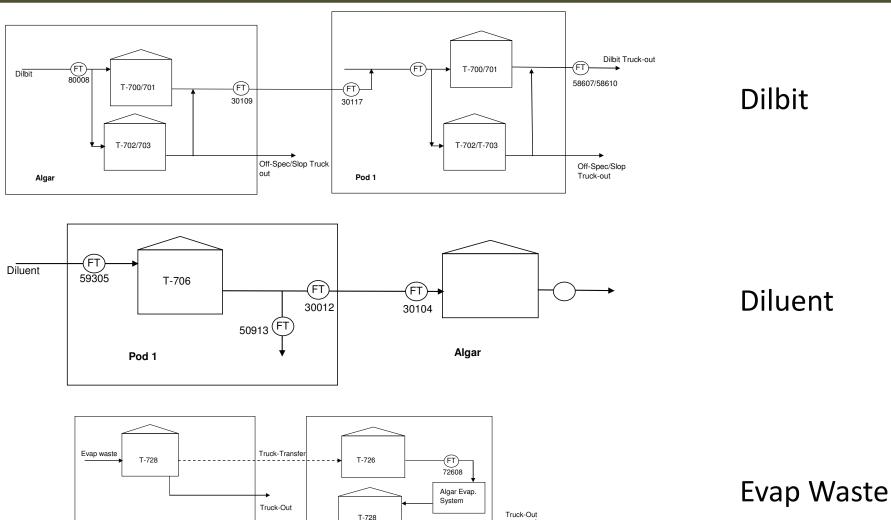
Algar Plant Layout





Pod One and Algar Integration





Algar

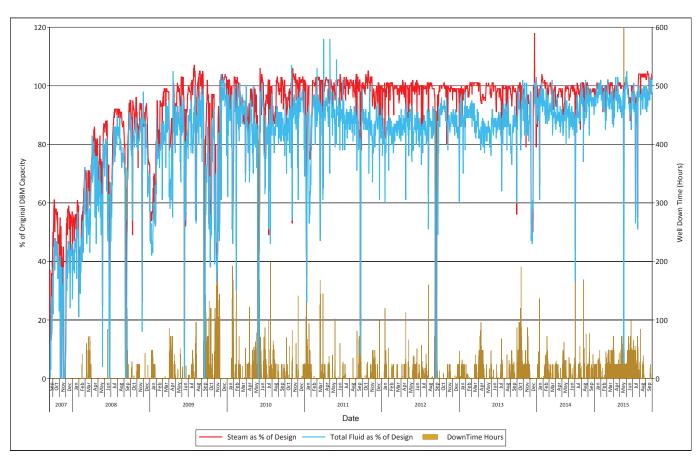
Pod 1





Pod One CPF Performance





The reliability considers the two steam Boilers at the plant.

For the period October 1, 2014 to September 30, 2015 the steam plant has averaged 98.8% of the original design basis (4,320 m3 /day) and 94.04% of the designed total fluid capacity (5,920 m3/day).

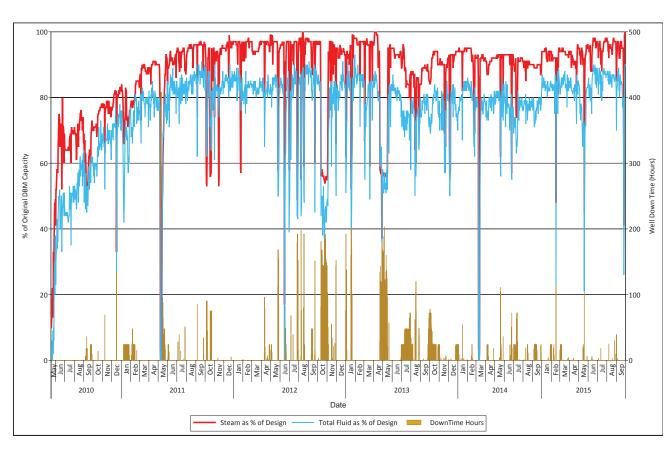
This performance compares to the previous 12 months. Which had a steam generation of 96% and a total fluid throughput of 90.2% of plant design capacity.

Reliability has been maintained in all areas of the operation

Downtime Hours is the reported downtime for the Well Pairs.

Algar CPF Performance





The reliability considers the two steam Boilers at the plant. The Cogen steam is not included.

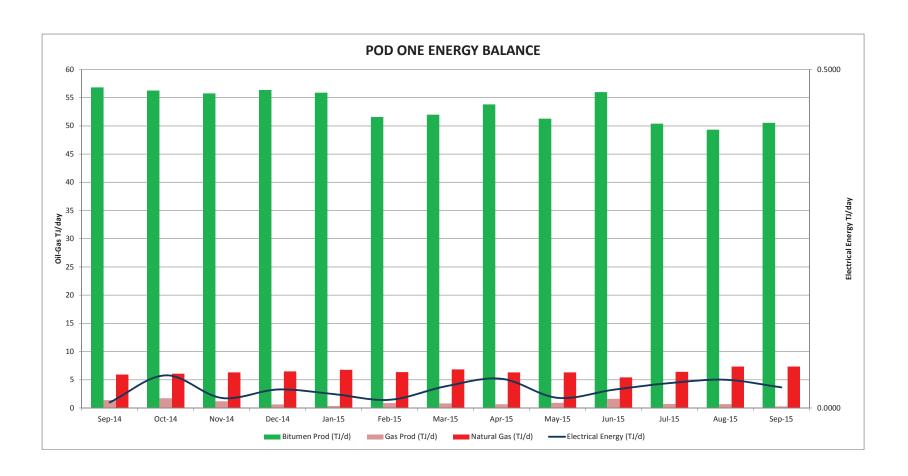
For the 12 months from October 1 2014, to the of September 30, 2015 the steam plant output has averaged 82.43% of the original design basis (4800 m3 /day) and 82.73% of the designed total fluid handling capacity (6400 m3/day).

This performance compares to the previous 12 months which had a steam generation of 82.7% and total fluid throughput of 81.3% of plant design capacity.

Downtime Hours is the reported downtime for the Well Pairs.

Pod One Energy Balance

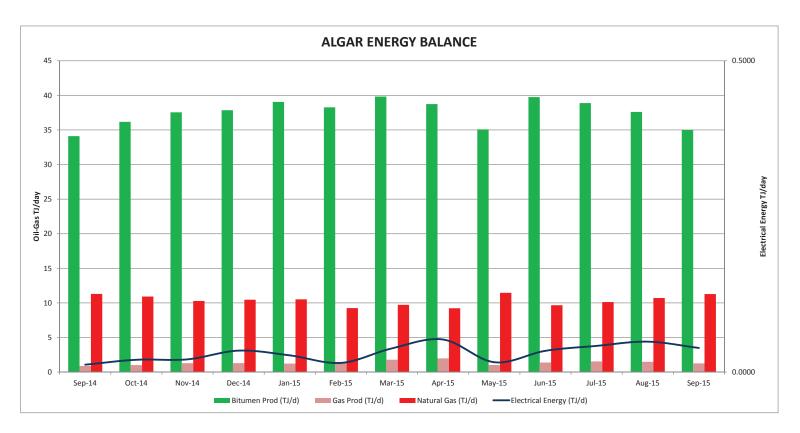




Greenhouse Gas Emissions Reported for December, 2014 = 232993.18 t CO₂ equivalent

Algar Energy Balance





Greenhouse Gas Emissions Reported for December, 2014 = 271789.56 t CO₂ equivalent

Algar Co-Generation Facility



- Designed to produce 13.1 MW electricity from GT and 588 m³/d of steam from the HRSG
- Horse River sub-station on line June 2011
- Running near capacity with power distributed to both Algar and Pod One
- Steam being used at Algar





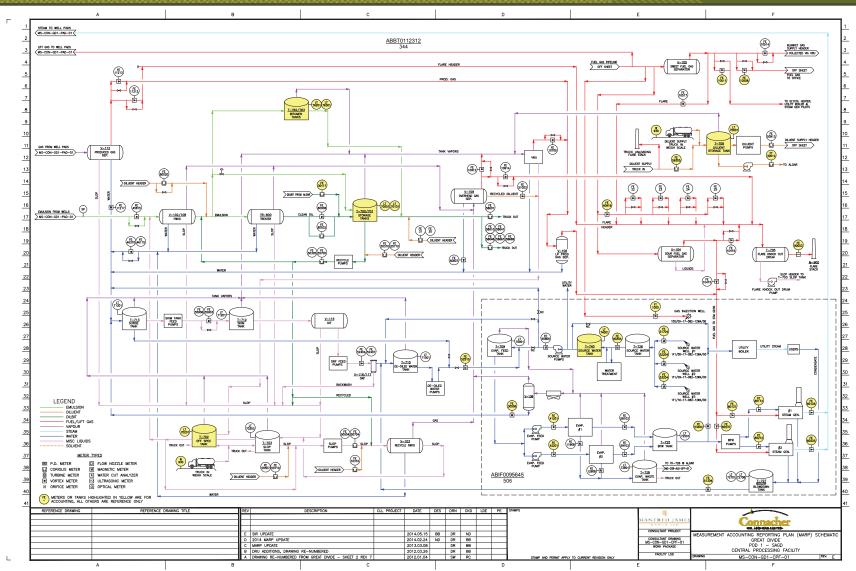
Changes to MARP



1. There are no changes to MARP for the reporting period.

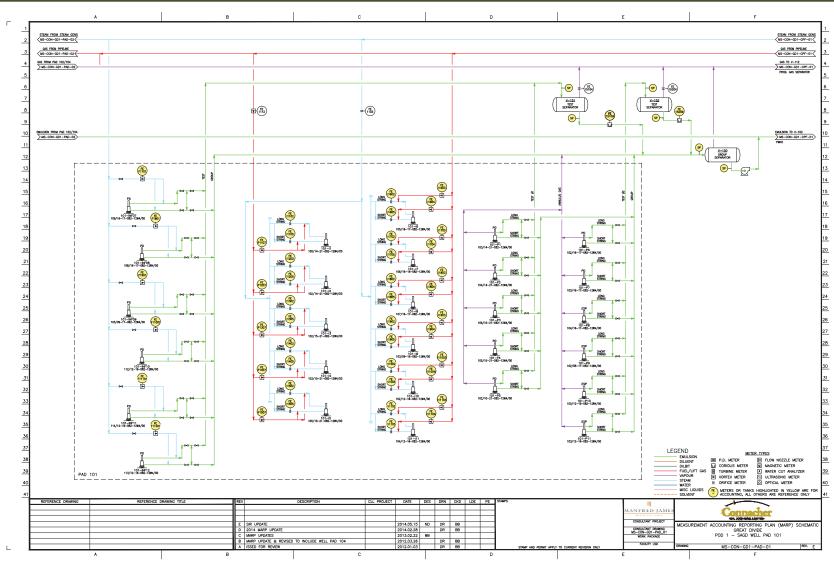
Pod One MARP - CPF





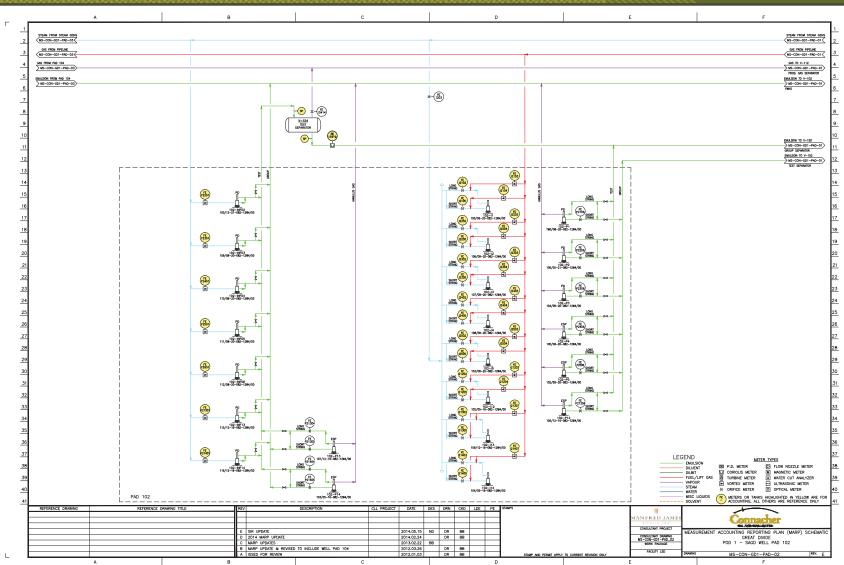
Pod One MARP - Pad 101





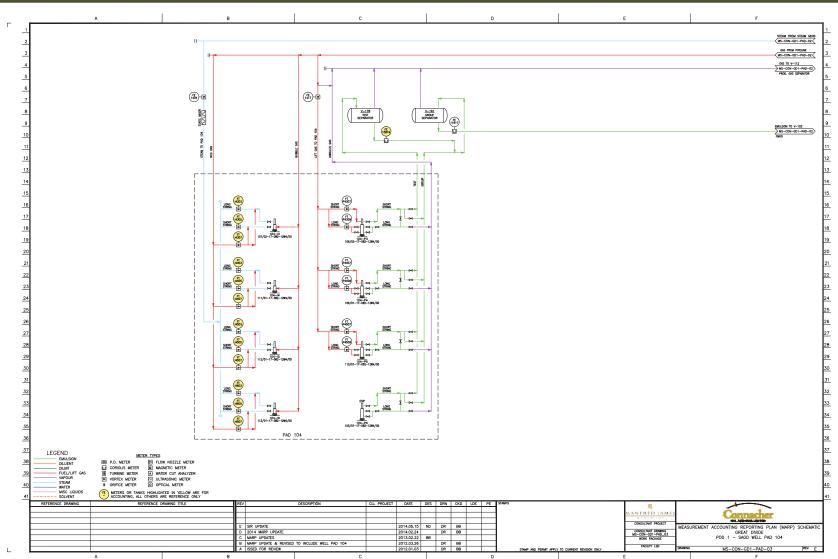
Pod One MARP - Pad 102





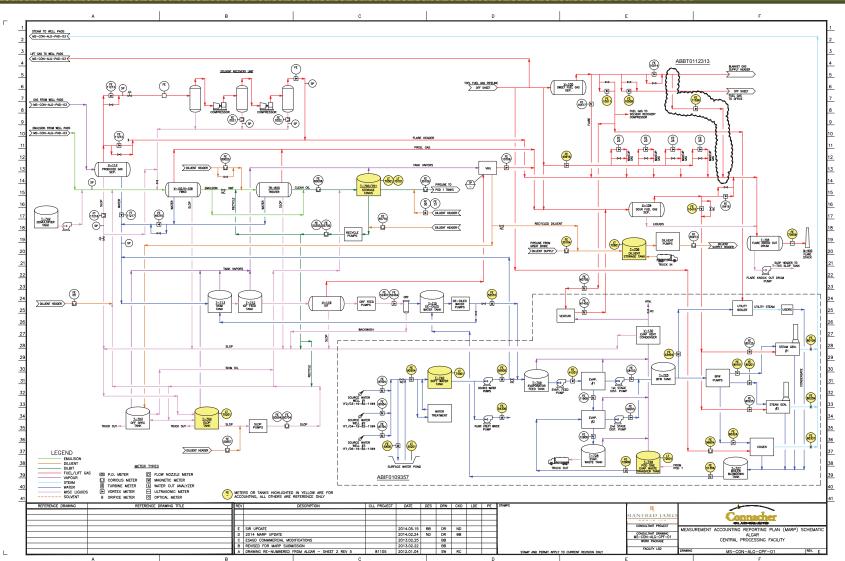
Pod One MARP - Pad 104





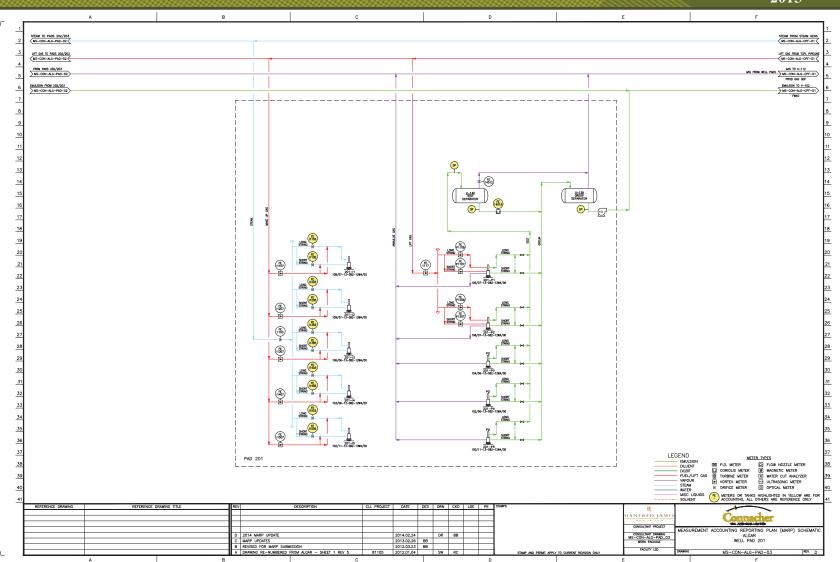
Algar MARP - CPF





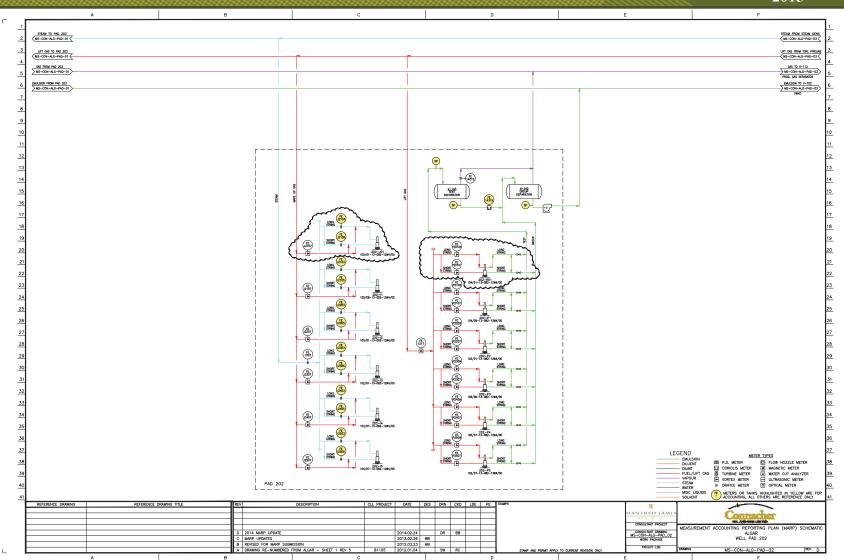
Algar MARP - Pad 201





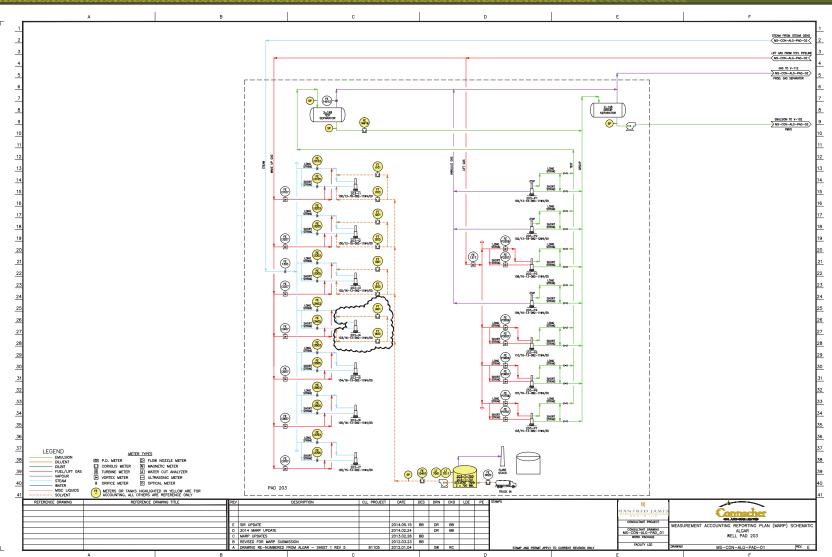
Algar MARP - Pad 202





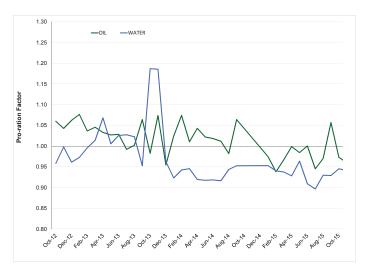
Algar MARP - Pad 203





Pod One and Algar Profacs



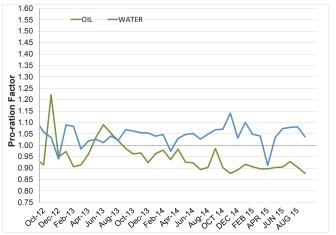


Pod One uses manual oil cuts however procedures implemented 2012 are clearly showing improved results.

An Agar oil cut meter is installed at Algar and work is progressing on the calibration however oil cuts are still reported from manual cuts.

The profac at Algar is calculated from the interconnect pipeline volumes whereas the Pod One profac is calculated from truck receipts less the Algar pipeline volumes and is subject to typical truck measurement differences.





Algar

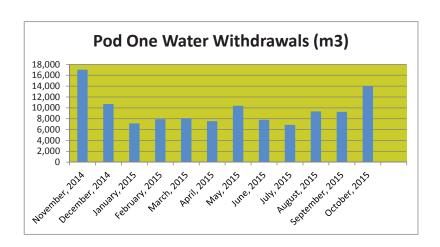




Source Water Wells - Pod One

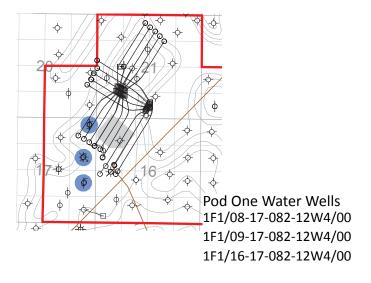


Year	Pod One Water Withdrawals (m³/year)	Licenced Maximum Annual Diversion (m³/year)
2011	107471	292,000
2012	132670	292,000
2013	92462	292,000
2014	99722	292,000
2015	89630	292,000



All wells use the Grand Rapids Formation for source water.

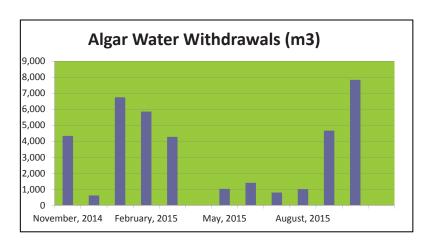
Water Act Licence 00240458-01-00			
Well Location	Production Interval (meters below grade)		
16-17-082-12 W4M	300 - 350		
09-17-082-12 W4M	300 - 350		
08-17-082-12 W4M	300 - 350		
02-17-082-12 W4M (standby)	324 - 330		



Source Water Wells - Algar

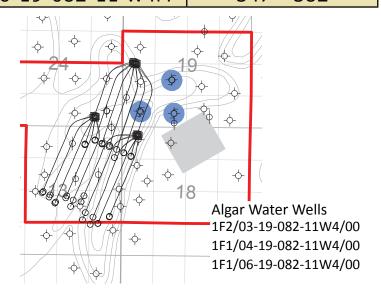


Year	Algar Water Withdrawals (m³/year)	Licenced Maximum Annual Diversion (m³/year)
2011	68222	330,000
2012	96164	330,000
2013	78917	330,000
2014	40683	330,000
2015	33598	330,000



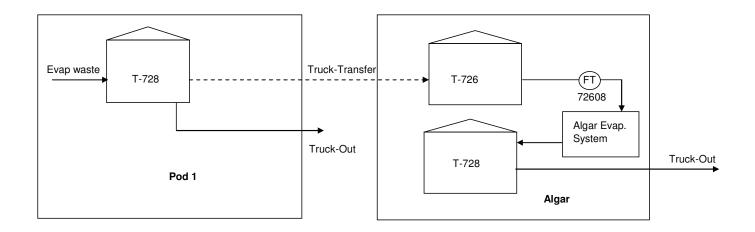
All wells use the Grand Rapids Formation for source water.

Water Act Licence 00240527-00-02				
Well Location	Production Interval (meters below grade)			
02-19-082-11 W4M standby	356 - 382			
03-19-082-11 W4M	349 - 382			
04-19-082-11 W4M	350 - 382			
06-19-082-11 W4M	347 - 382			



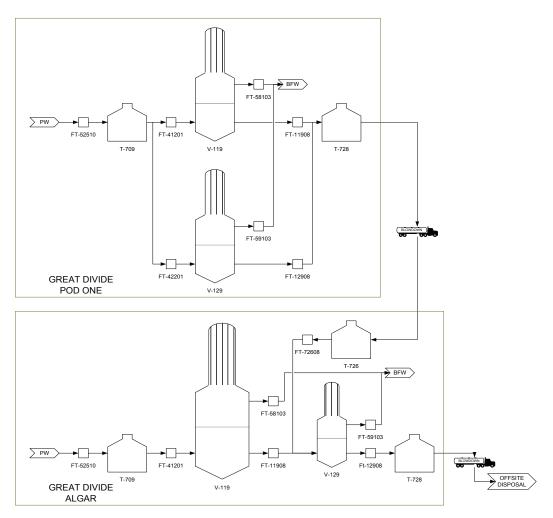
Evaporator Waste Integration





Integrated Water Recycle Scheme

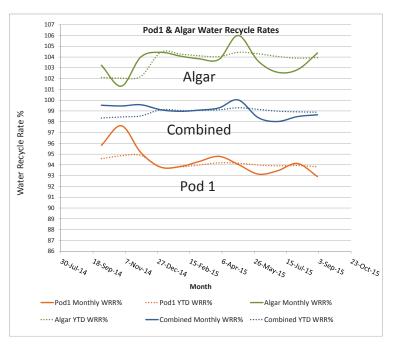




- Evaporators produce high quality boiler feed water efficiently while generating a highly concentrated brine for disposal.
- At Algar a second stage evaporator further concentrates both the Algar brine and a portion of the Pod One brine to improve water reuse and minimize disposal.
- Disposal concentrations are close to crystallizer performance.
- Chemical optimization has significantly improved evaporator reliability.

Water Recycle Ratio





Month	Pod1 Monthly WRR%	Pod1 YTD WRR%	Algar Monthly WRR%	Algar YTD WRR%	Combined Monthly WRR%	Combined YTD WRR%
Oct-14	95.8	94.6	103.2	102.1	99.5	98.3
Nov-14	97.6	94.9	101.3	102.0	99.5	98.4
Dec-14	95.1	94.9	104.0	102.2	99.6	98.5
Jan-15	93.8	93.8	104.4	104.4	99.1	99.1
Feb-15	93.9	93.8	104.1	104.3	99.0	99.0
Mar-15	94.3	94.0	103.8	104.1	99.1	99.1
Apr-15	94.8	94.2	103.8	104.0	99.3	99.1
May-15	94.0	94.2	106.0	104.4	100.0	99.3
Jun-15	93.1	94.0	103.6	104.3	98.4	99.1
Jul-15	93.5	93.9	102.6	104.1	98.0	99.0
Aug-15	94.1	93.9	102.8	103.9	98.5	98.9
Sep-15	92.9	93.8	104.4	103.9	98.6	98.9
Average						98.9

- The series evaporator operation at Algar provides high recycle rates and improved reliability.
- The Algar operation accommodates waste from the parallel evaporators at Pod One and brine is shipped from Pod One to Algar.
- By treating part of the Pod One blow-down at Algar the average yearly water recycle ratio for both plants is approximately 98.9%.

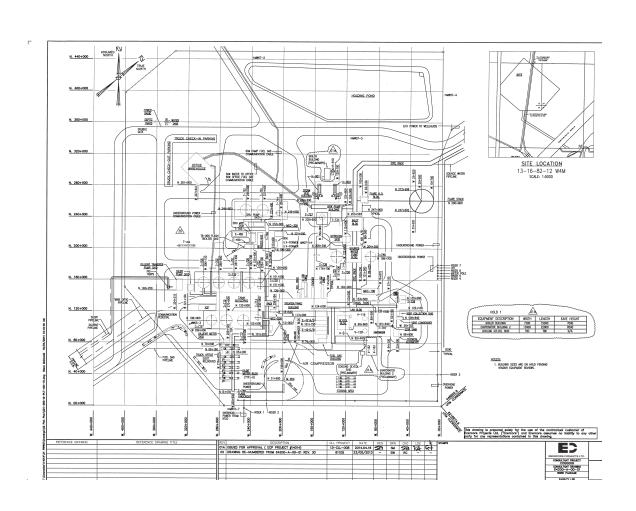




Pod One - Mini Steam Expansion



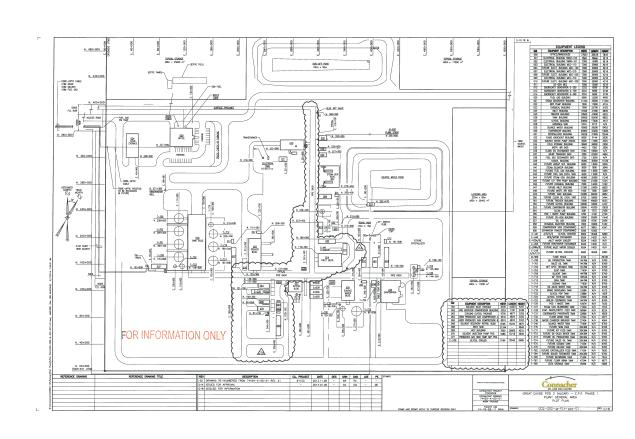
- Commercial Scheme Approval 10587P.
- 500 t/d of steam.
- Allows for 2 Well Pair at Pad 104.
- Steam Generator (17.26 MW).
- 2 Evaporator Units.
- SIR 1 Submitted for EPEA Amendment.
- No additional water allocation required.



SAGD+® Process Commercial



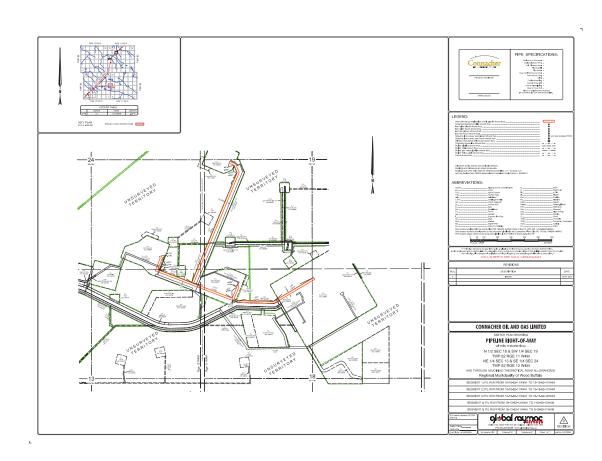
- Commercial Scheme Approval 10587K.
- Light hydrocarbon (solvent) and steam co-injection at all well pairs at Algar.
- Solvent to be recovered at facility for re-injection.
- EPEA 67(3) No objection received May, 2014.
- Construction began August,
 2014 but not yet completed.



SAGD+® Process Commercial (pipelines)



- Commercial Scheme Approval 10587K.
- 3 inch light hydrocarbon pipeline to all well pads.
- Installed on existing pipe rack.
- Construction completed but not yet commissioned.



Algar - New Pad Development





Near Future Development to include:

- Pad 232 (Phase 1A)
- Borrow Pit
- Utility Corridor





Pod One Sulphur Emissions



Quarter	Average Sulphur Dioxide Emissions (t/day)
Q4 - 2014	0.55
Q1 - 2015	0.45
Q2 - 2015	0.42
Q3 - 2015	0.41

- Pod One EPEA SO₂ emission limit is 1.98 t/day
- Peak SO₂ emissions were 0.65 t/day on Oct 12&14, 2015

- Plant Total SO₂ = Flared SO₂ + Steam Generators SO₂
- There has been no material change in sulphur production observed over the past year of production at Pod One
- Connacher will continue to monitor produced gas H₂S concentrations, sulphur emissions and evaluate plans for sulphury recovery installations
- SO₂ production is well below emission limits

Algar Sulphur Emissions



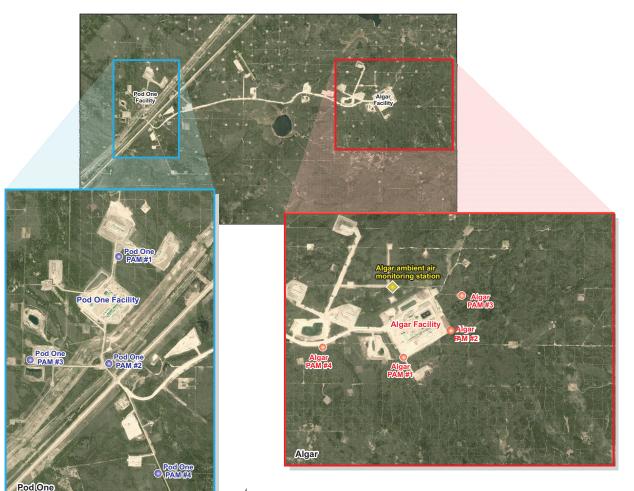
Quarter	Average Sulphur Dioxide Emissions (t/day)
Q4 - 2014	0.71
Q1 - 2015	0.75
Q2 - 2015	0.77
Q3 - 2015	0.74

- Algar EPEA SO₂ emission limit is 1.98 t/day
- Peak SO, emissions were 1.11 t/day on Feb 17, 2015

- Plant Total SO₂ = Flared SO₂ + Steam Generators SO₂
- There has been no material change in sulphur production observed over the past year of production at Algar
- Connacher will continue to monitor produced gas H₂S concentrations, sulphur emissions and evaluate plans for sulphury recovery installations
- SO₂ production is well below emission limits

Ambient Air Quality Network

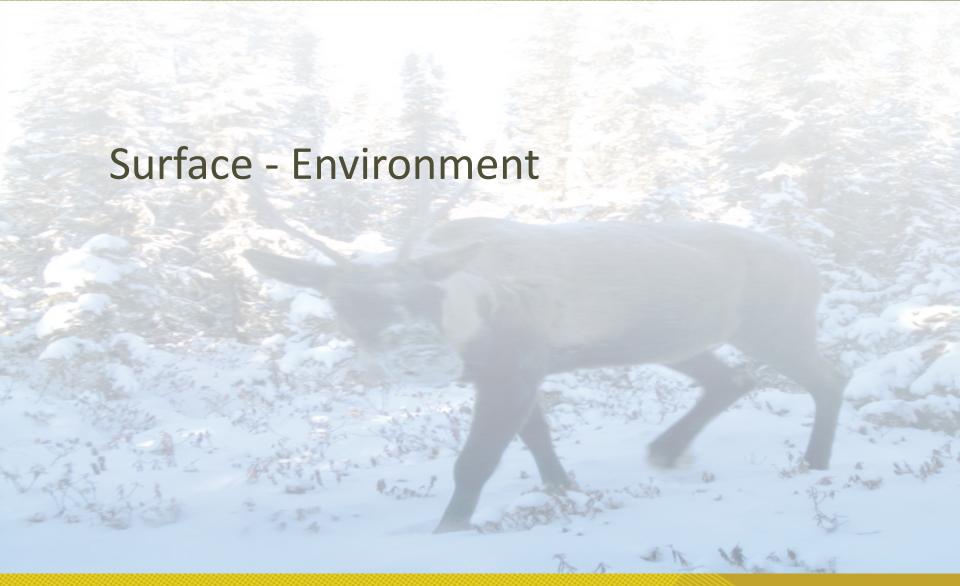




There are a total of 8 passive air monitoring stations at Pod One and Algar. These sites monitor for SO₂ and H₂S. For the reporting period there were no exceedances of the AAAQO

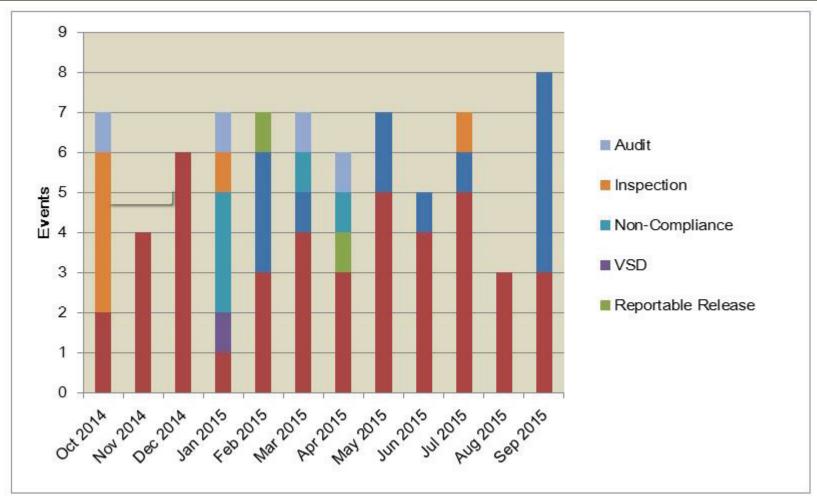
Connacher is required to complete continuous ambient air monitoring station for SO₂, H₂S and NO₂, as well as wind speed and wind direction. This monitoring is required 6 months per year. For the reporting period all measured concentrations were within the AAAQO's.





Great Divide Compliance





Great Divide Applications / Authorizations



Approval Date	Authorization No.	Description
December 4, 2013	10587M	Pod One Full Field NCG Co-injection Scheme Approval
December 12, 2013	10587N	Pod One - Pad 101 and Pad 102 Infills (9) Scheme Approval
January 8, 2014	105870	SAGD+® Trail Pad 104 Scheme Approval
March 21, 2014	10587P	Mini-Expansion at Pod One Scheme Approval
Pending	Pending	EPEA Approval Amendment for Mini-Expansion at Pod One
June 10, 2014	F36853	Pod One Facility Licence Amendment
August 1, 2014	F40209	SAGD+® Commercial Project Facility Licence Amendment
August 13, 2014	56423	SAGD+® Commercial Project Solvent Pipeline Licence
September 10, 2014	10587Q	Algar - Pad 203 Infills (5) Scheme Approval
October 1, 2014	10587R	Algar Full Field NCG Co-injection Scheme Approval
Pending	Pending	Algar Water Act Licence 240527-00-00 Renewal
Pending	Pending	Pod One Water Act Licence 240458-01-00 Renewal

Great Divide Inspections, Audits and VSDs



Inspection Date	Licence Number	Location	Inspection Result
October 8, 2014	51876	01-24-082-12 W4M	Satisfactory
October 8, 2014	54978	01-24-082-12 W4M	Satisfactory
October 8, 2014	51620	14-18-082-11 W4M	Satisfactory
October 8, 2014	48792	13-16-082-12 W4M	Satisfactory
October 8, 2014	40209	15-18-082-11 W4M	Satisfactory
January 1, 2015	36853	13-16-082-12 W4M	Satisfactory
July 1, 2015	240008-00-04 (EPEA)	13-16-082-12 W4M	Satisfactory

Audit Date	Licence Number	Location	Issue and Resolution
October 2014	10587	Great Divide SAGD	Injection Pressure audit.Technical data submitted. Closed
January 2015	W0450332	Pad 202 PO1-1	Unsatisfactory; failure to submit drilling waste records within 24 months of rig release. Closed
March 2015	W0455341	AC/09-22-082-12W4M	Unsatisfactory; failure to submit drilling waste records within 24 months of rig release. Closed
April 2015	W0445265	07/02-17-082-12W4M	Unsatisfactory; failure to submit drilling waste records within 24 months of rig release. Closed

Voluntary Self Disclosures



VSD	Licence Number	Location	Issue and Resolution
September 2014	W0374122	Pad 101N-I03	CLC failed to complete casing inspection log&install casing corrosion coupon in well by July 30th,2015. Closed Nov 21/2015
September 2014	multiple	various at Great Divide	CLC aquired several inactive pipelines within the Great Divide area that were not properly suspended or abandoned. Ongoing; AER granted an extension to complete pipeline discontinuation activities to March 31,2016
January 2015	W0450336	105/01-13-082-12W4M	Low risk NC, failure to submit drilling waste records within 24 months indentified by an internal audit. Closed

Great Divide Monitoring Programs



Connacher currently implements the following monitoring programs at the Great Divide Project:

- Groundwater monitoring program;
- Wildlife monitoring program (approved in late 2014);
- Ambient air monitoring program;
- Industrial wastewater and Industrial runoff monitoring program; and,
- Soil monitoring program.

As required by its EPEA Approval, Connacher has recently submitted to the AER the following:

- Caribou Mitigation Plan and Monitoring Program;
- Wildlife Mitigation Plan and Monitoring Program.
- Wetland Monitoring Program Proposal (December 2014)
- Soil Monitoring Program Proposal (January 2015)





Additional Material Attached to Submission



<u>Additional Material Attached to Submission:</u>

Pressure & temperature data form observation wells for Pod One & Algar in prescribed AER Format

Energy Usage & Balance for Algar & Great Divide

Electrical Use at Pod One & Algar

SCVF GM Testing Results

Connacher Heave monitoring Data

Pump Histories





Bitumen Reserves and Resources



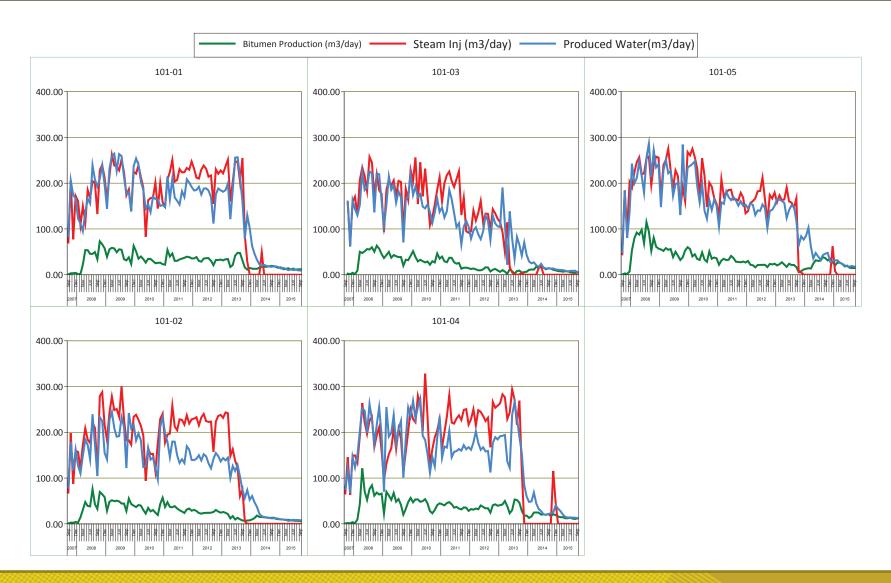
- 1)Proved reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.
- 2)Probable reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.
- 3)Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated proved plus probable plus possible reserves. Possible reserves were 128 million barrels as at Dec 31, 2014 per GLJ. There is a 10% probability that the quantities actually recovered will equal or exceed the sum of the proved plus probable plus possible reserves.





Pod One Pad 101N Individual Well Performance





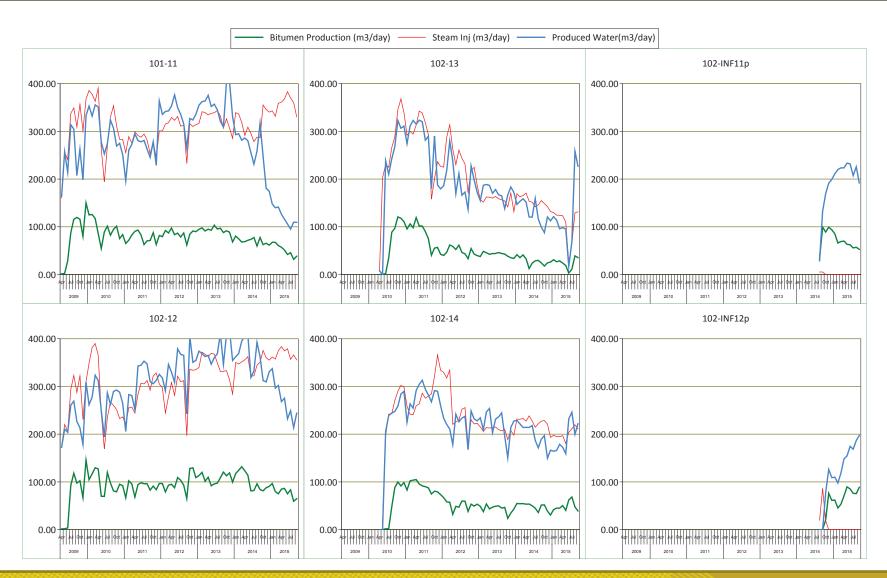
Pod One Pad 101S Individual Well Performance





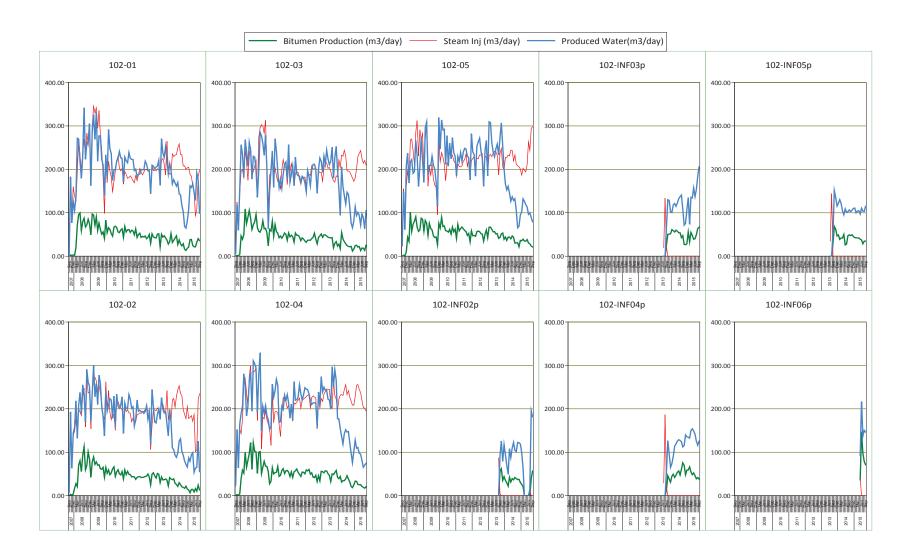
Pod One Pad 102S Individual Well Performance





Pod One Pad 102W Individual Well Performance Con





Pod One Pad 104 Individual Well Performance





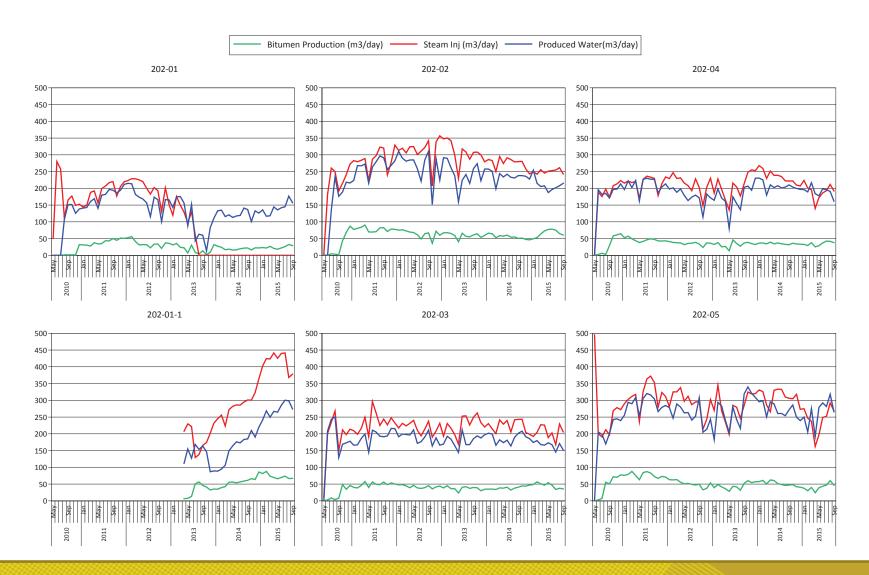
Algar Pad 201S Individual Well Performance





Algar Pad 202S Individual Well Performance





Algar Pad 203 Individual Well Performance



