Annual Performance Presentation

BAYTEX 2015

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Gemini Approval No. 11789B

August 2015

Overview – Subsurface

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Overview – Surface

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5. Sulphur Emissions
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Subsurface

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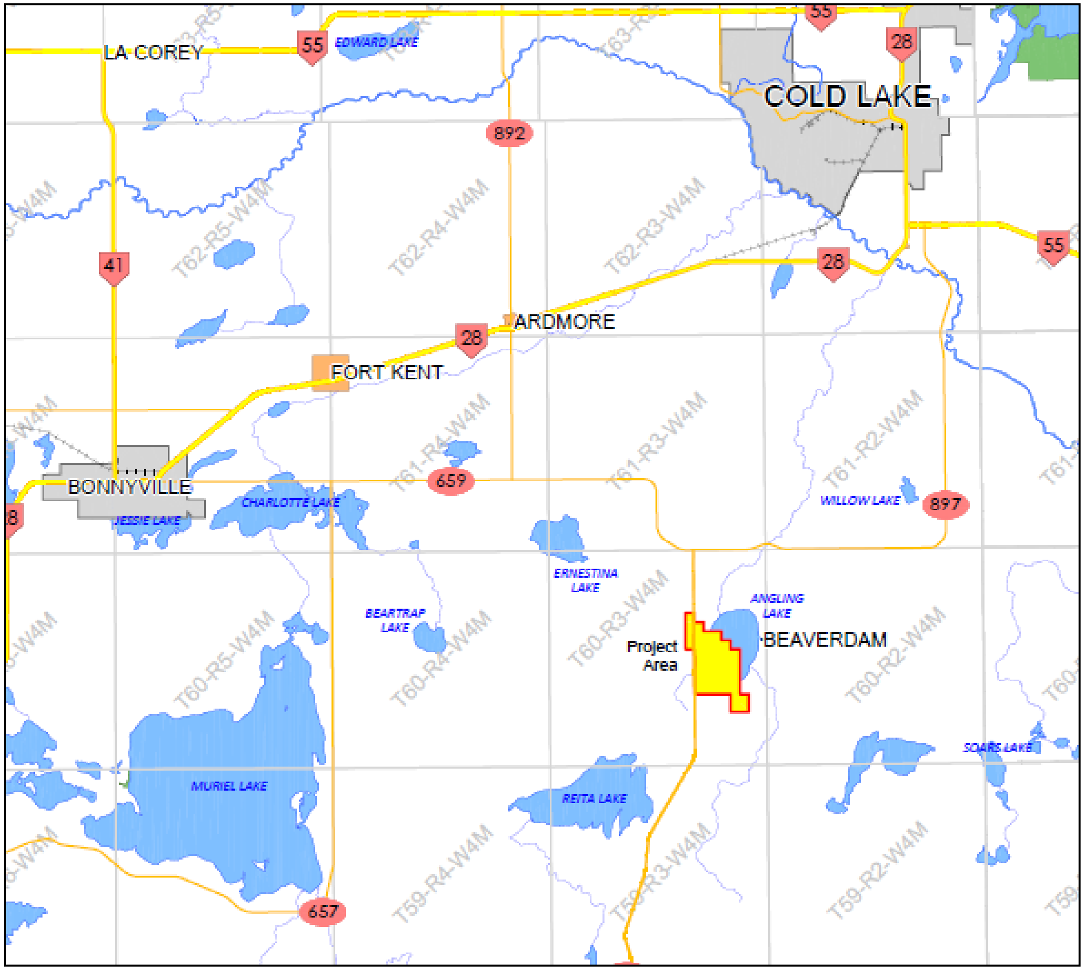
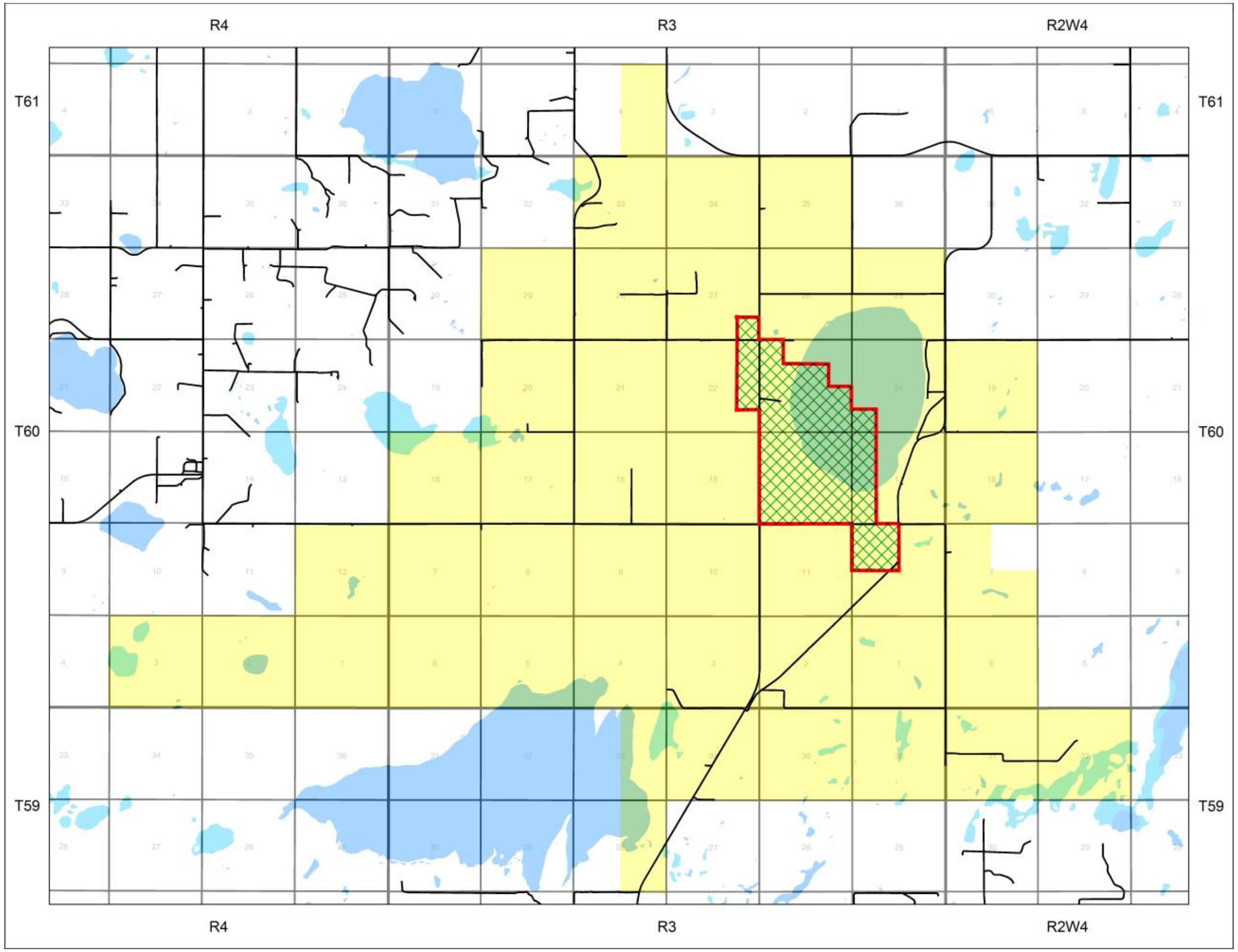
Overview – Location

- Northeast Alberta near Bonnyville.
- Cold Lake Oil Sands Area.



Overview – Scheme Area

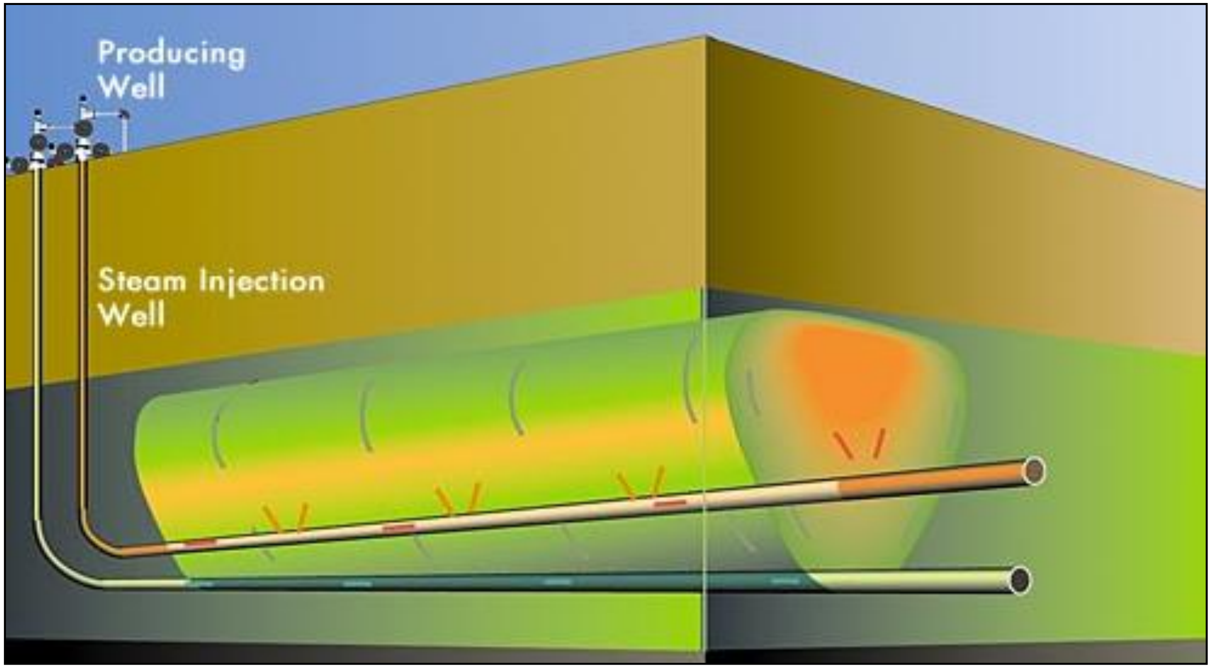
- Cold Lake Oil Sands Area.
- Township 60, Range 3, W4M.
- General Petroleum formation.



Overview – SAGD Development

Gemini Stage One

- Using Steam Assisted Gravity Drainage (SAGD) to recover bitumen from the General Petroleum formation.
- Single 600 m well pair, length matched to 50 MMBtu steam facility.
- Planned average Commercial length ~ 750m.

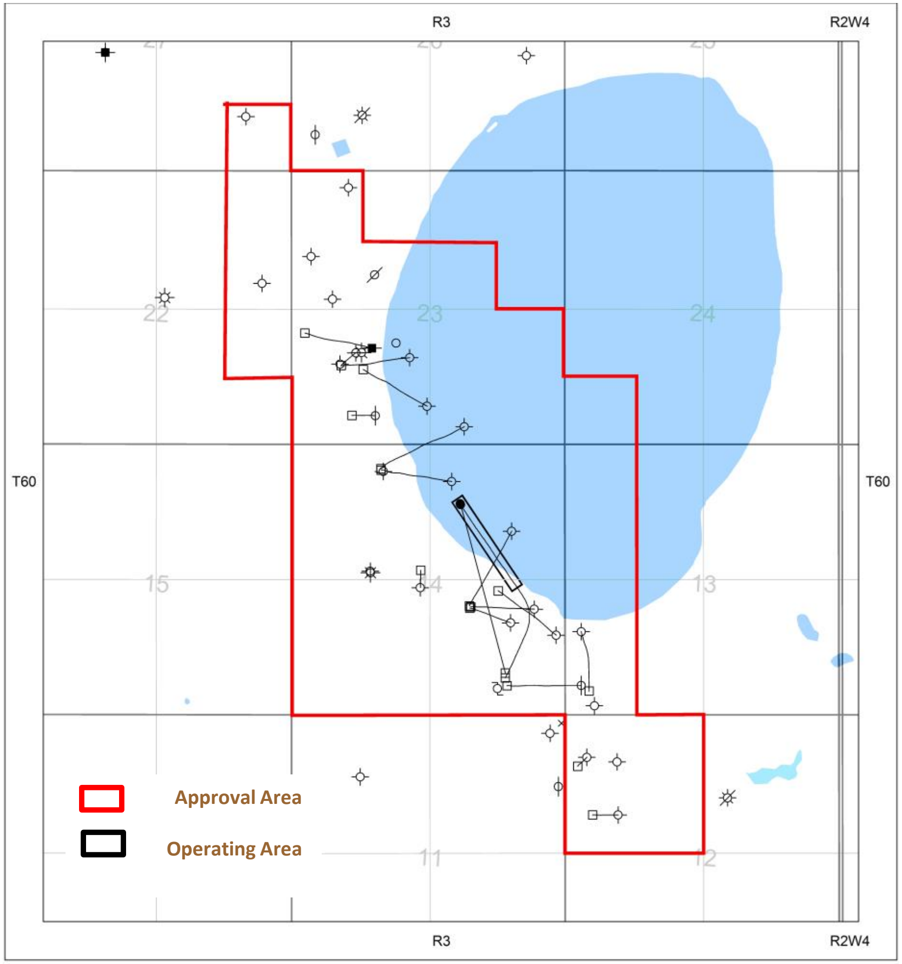


EnCana graphic

Overview – Approval History

Application Number		Project Summary	Approval No. and Date		Expiry Date
AER	AESRD		AER	AESRD	
1741545	N/A	Application to change the operator to Baytex Energy Ltd.	11789B November 1, 2012	N/A	N/A
1734633	N/A	Response to Condition 2 of ERCB Decision (Plan to mitigate the potential impacts to surface water bodies from wells and facilities associated with Pads 101 and 103)	11789A September 5, 2012	N/A	N/A
1617225	011-261830	Application for a Commercial Thermal Project at Gemini	11789 March 30, 2012	261830-00-00 April 19, 2012	March 31, 2022

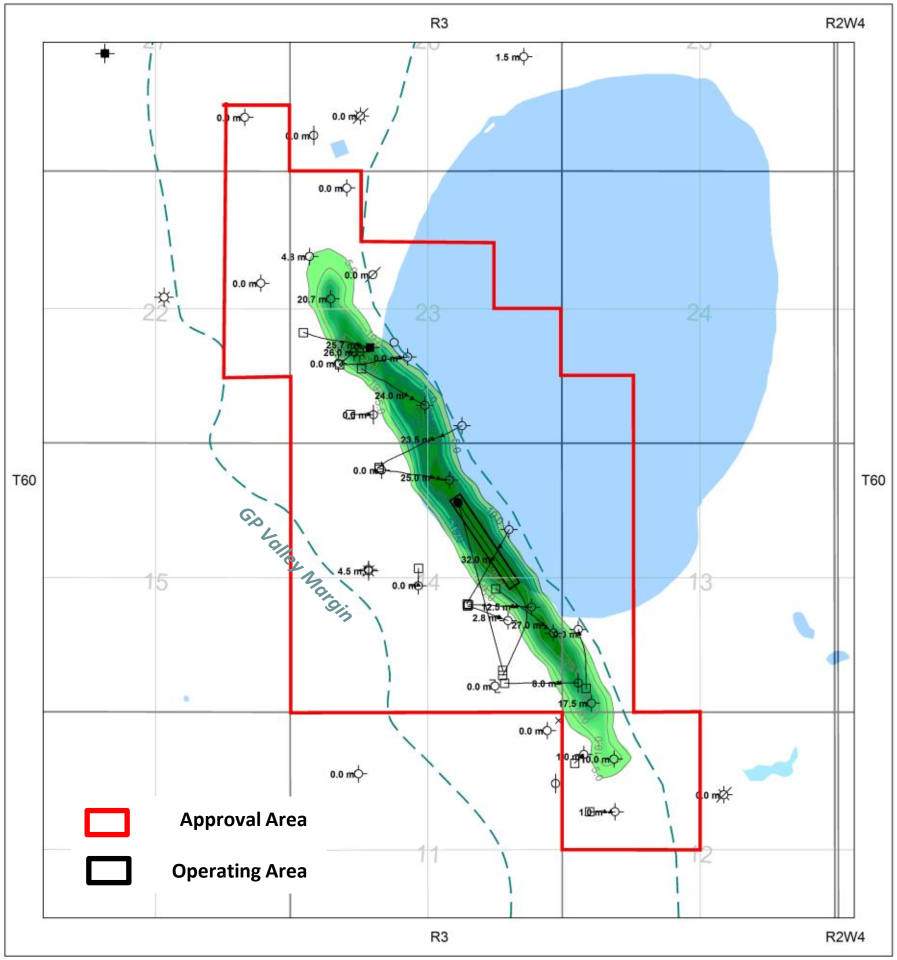
Geology/Geoscience – Reservoir Properties



Reservoir Attributes	Approval Area	Operating Area
Area (ha)	682	4.6
avgRes Depth (m)	398mTVD (+176mSS)	392mTVD (+177mSS)
Viscosity (cp)	50,000 to 280,000	50,000 to 280,000
Initial Reservoir T(°C) / P(kPa)	17 / 3000	17 / 3000
avgKmax (md)	2,800 to 6,400	2,800 to 6,400
avgH (m)	21.7	25.0
avgSo (frac)	0.8	0.8
avgPhi (frac)	0.33	0.33
OBIP (e^3m^3)	4,042*	277.2*

- OBIP = Area x Height x So x Phi
- *>10m Height (Net Bitumen Pay)

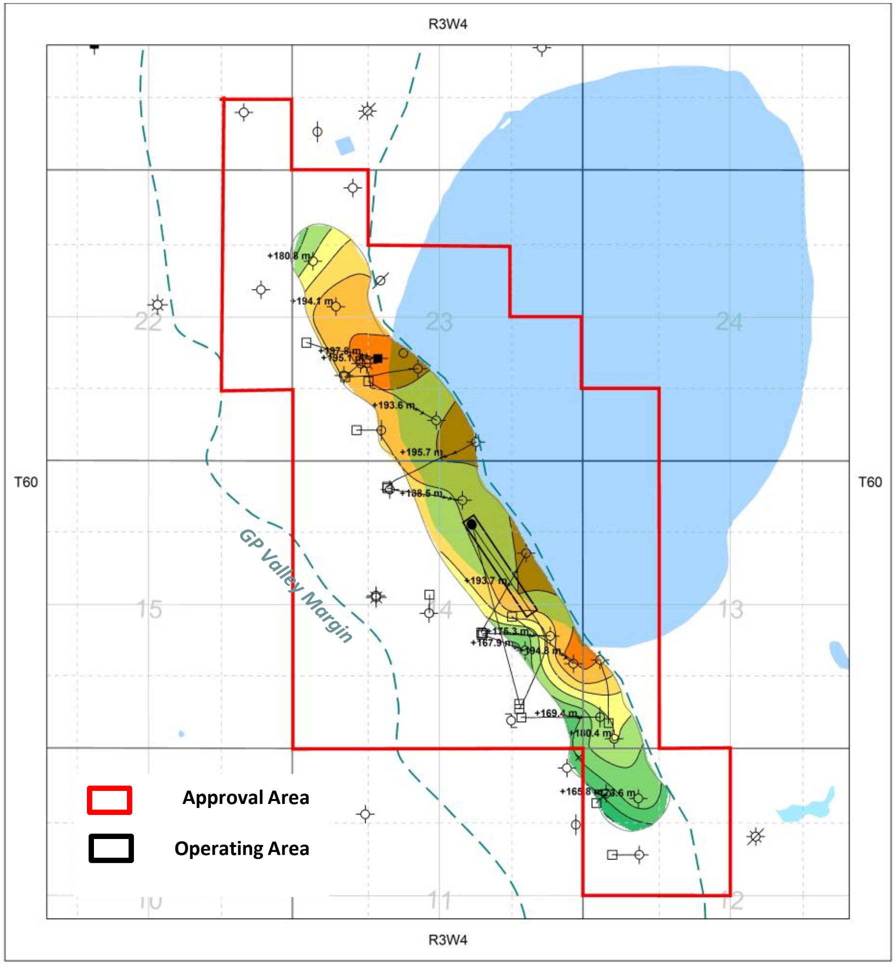
Geology/Geoscience – Net pay map



General Petroleum Net Bitumen Pay (m) – C.I. = 5m

- GP age incised valley system
  - Approximately 1,100m wide
- GP bitumen saturated sandstone
  - Approximately 300m wide, 3,600m long
- Net pay cutoffs
  - Gamma ray <60 API
  - Density porosity >30%
  - Deep resistivity >10ohm-m

Geology/Geoscience



General Petroleum Top Bitumen Structure (m) – C.I. = 5m

- Top bitumen structure falls off to the Southwest.
- Subtle drape / differential compaction at depositional edges.

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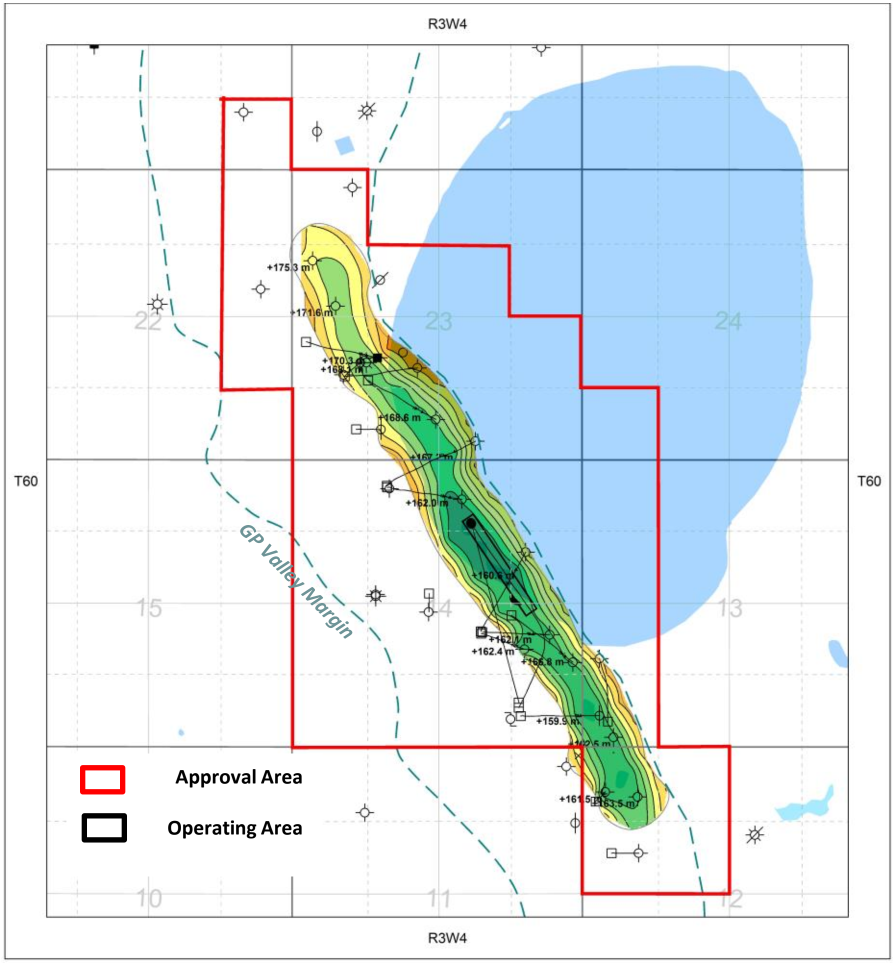
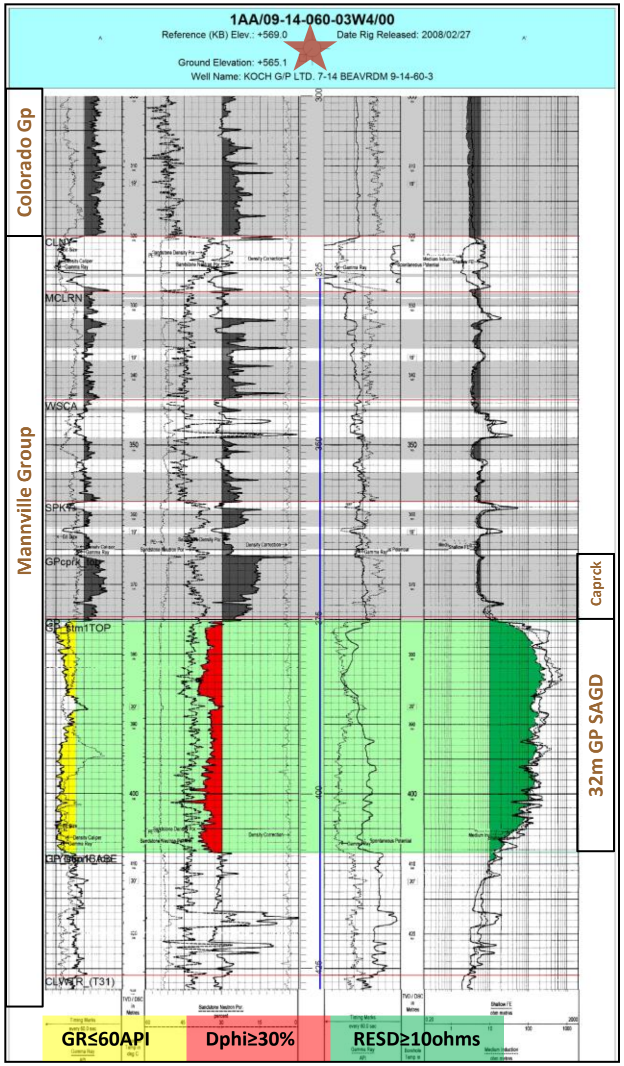
Geology/Geoscience – Structure Map



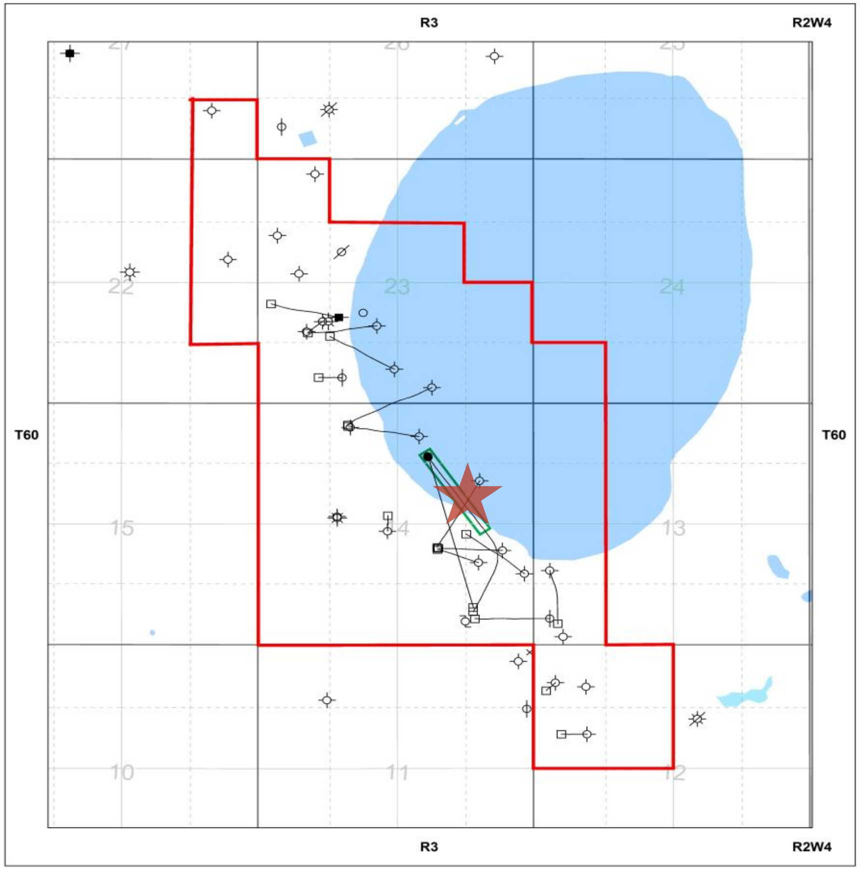
- Base bitumen structure relatively flat in and along channel axis.
- Steep structure along edges reflective of discrete deposition.

General Petroleum Base Bitumen Structure (m) – C.I. = 5m

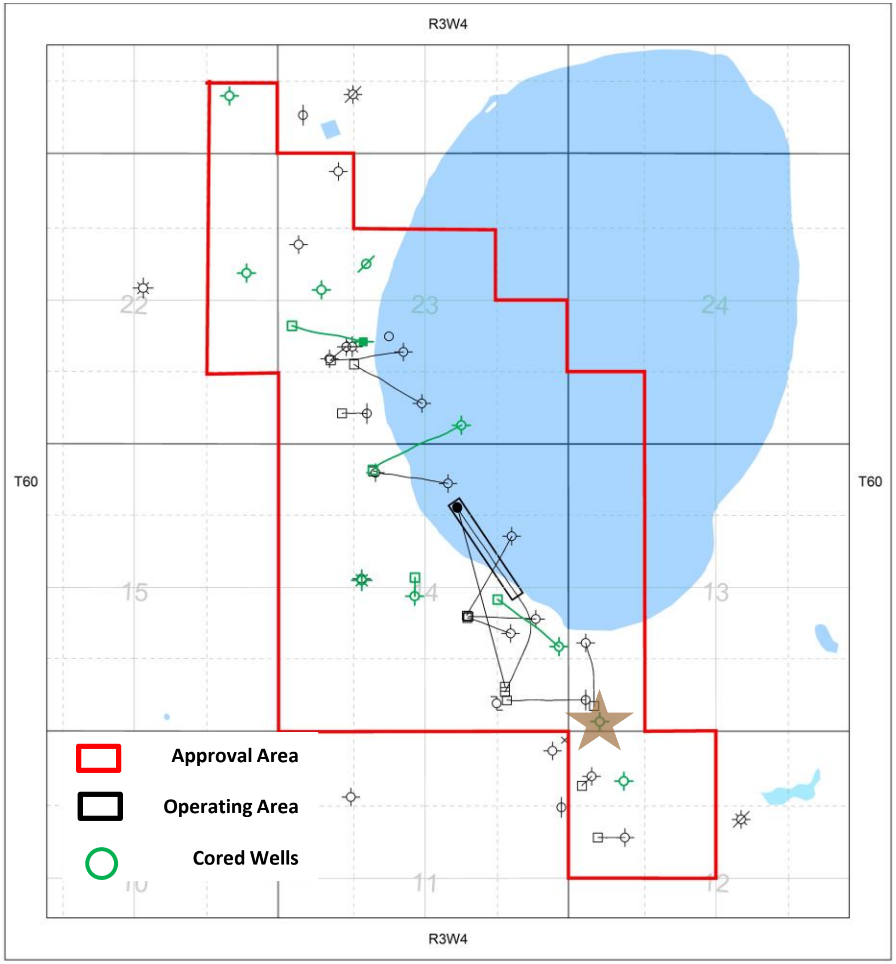
Geology/Geoscience – Type Log



- Thick, 32m of bitumen saturated GP sandstone.
- 9m marine shale caprock directly overlying bitumen.



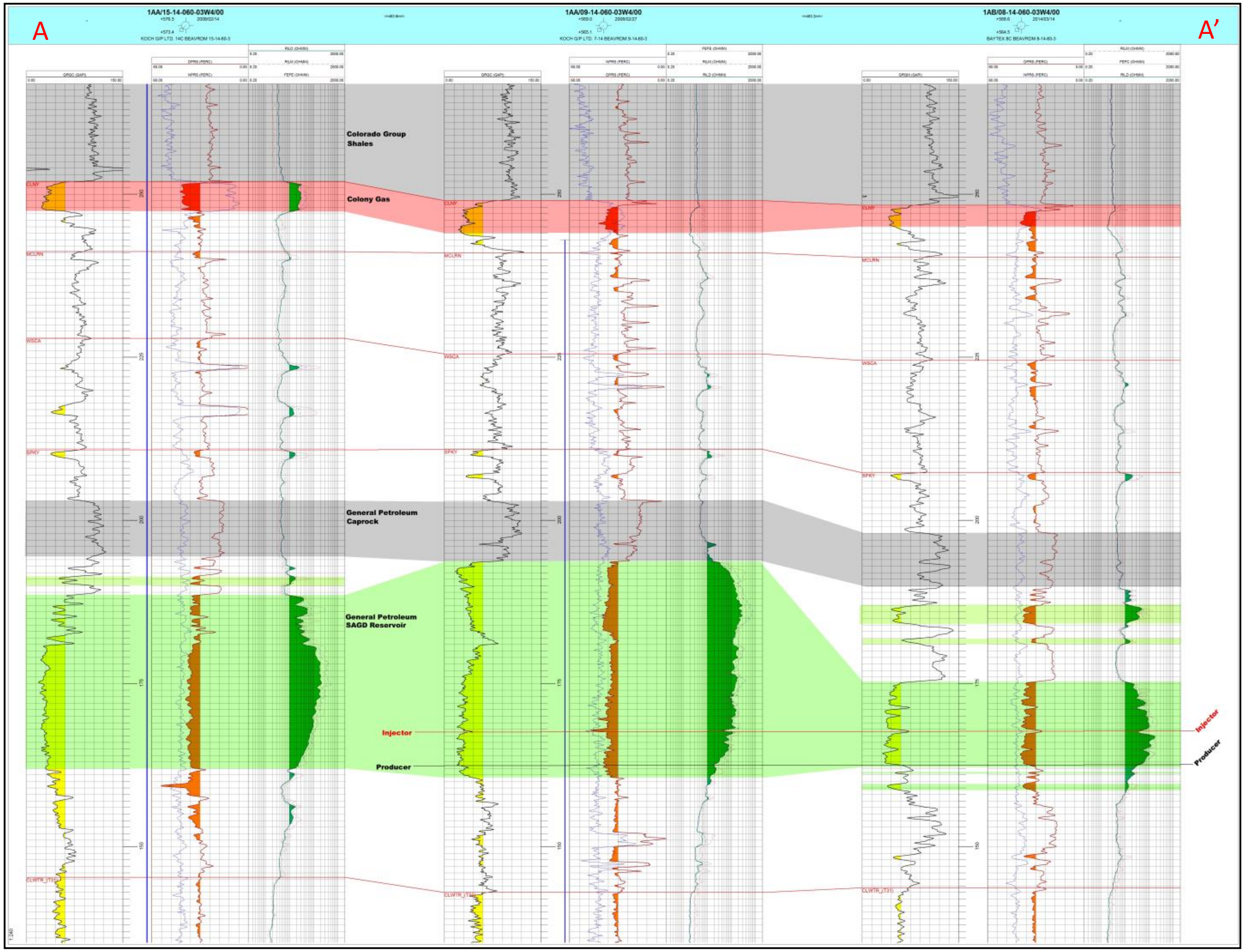
Geology/Geoscience – Strat/Core Wells

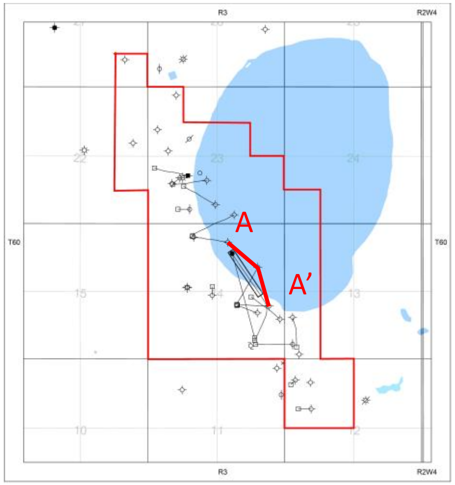


- 11 cored wells over the General Petroleum in the Project area
- 1AA/04-13-060-03W4 with caprock integrity analysis

General Petroleum cored wells

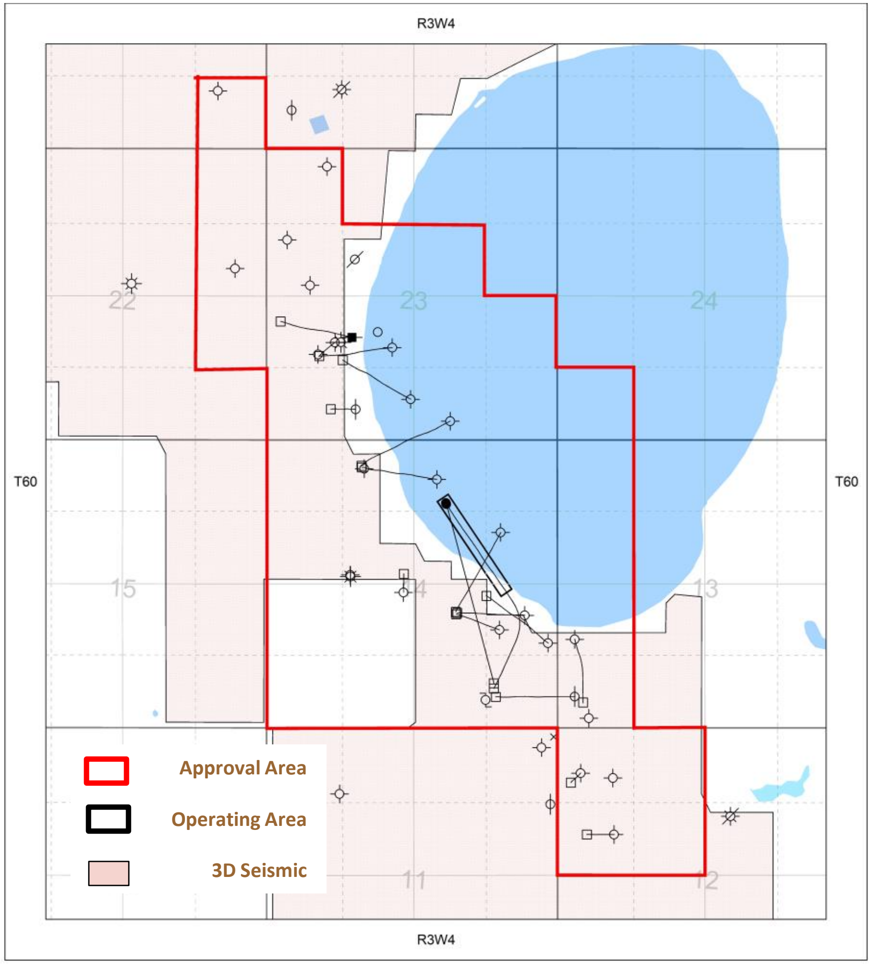
Geology/Geoscience – Cross section





General Petroleum Structural Cross Section

Geology/Geoscience – Seismic Coverage

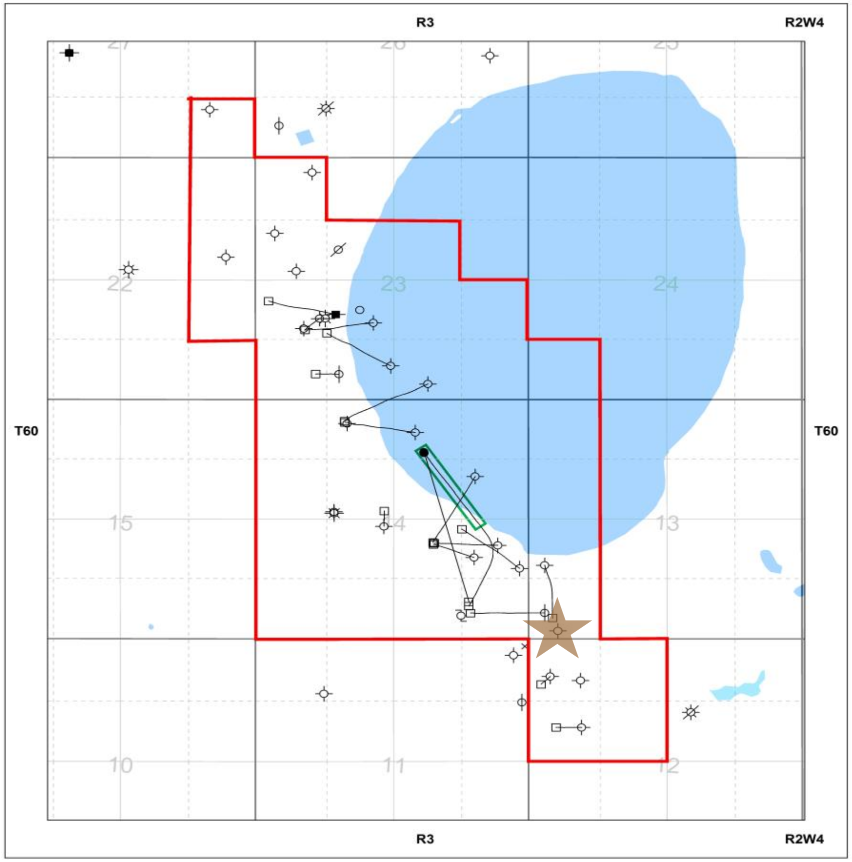


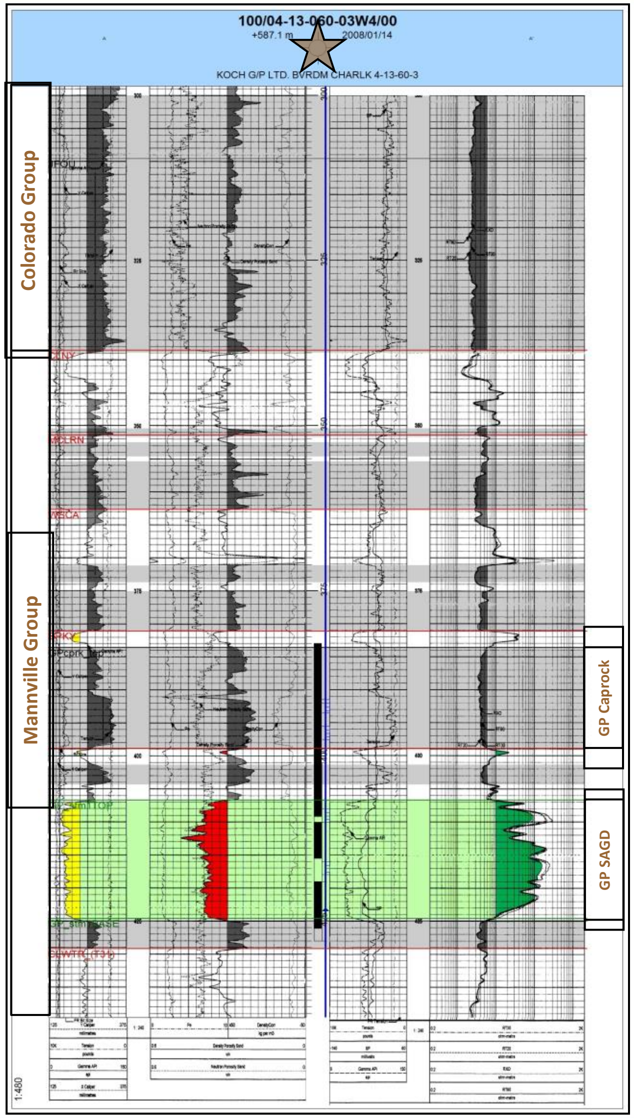
- 3.376 km^2 3D seismic within approved area.

3D Seismic coverage

Geomechanics

- 100/04-13-060-03W4 Mini Frac.



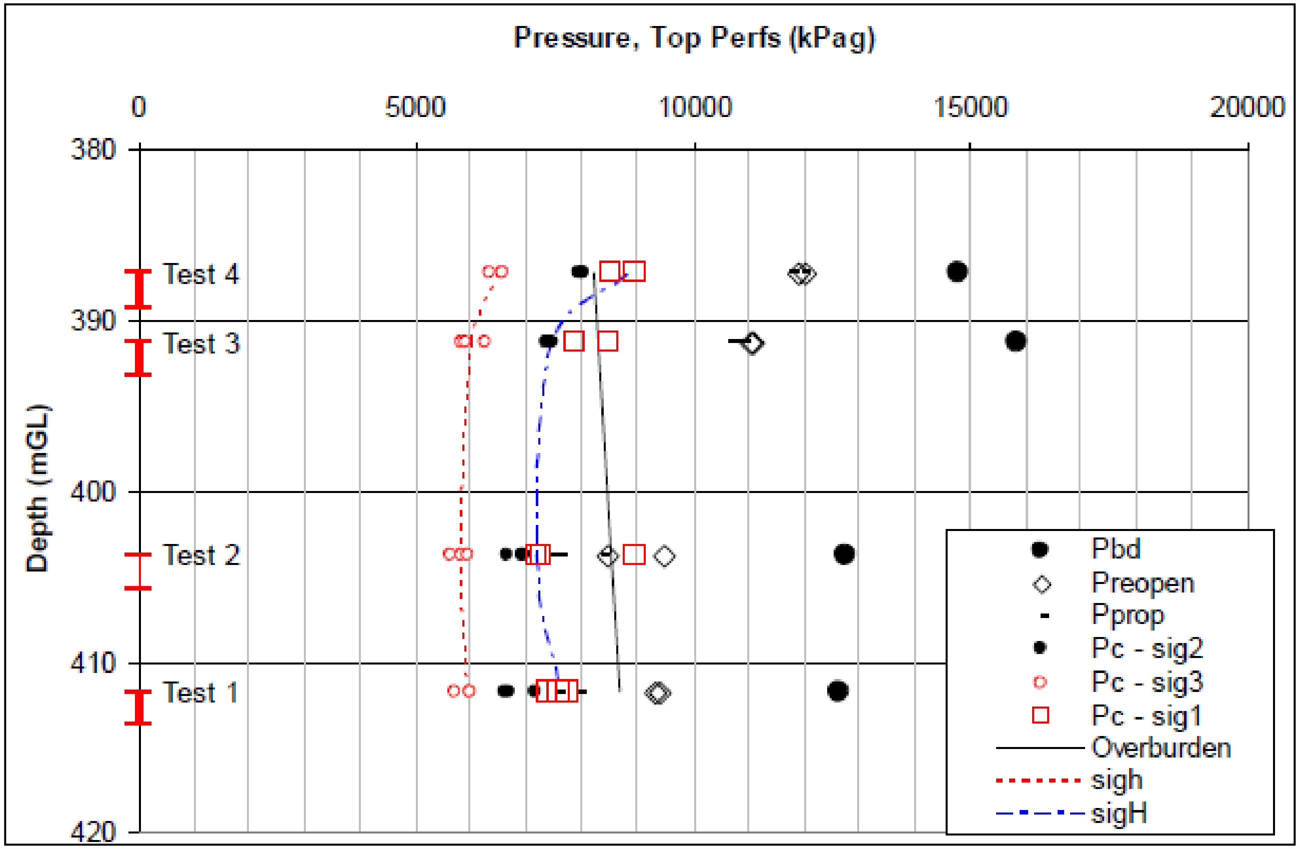


Geomechanics

- 100/04-13-060-03W4 Measured Frac Pressures.

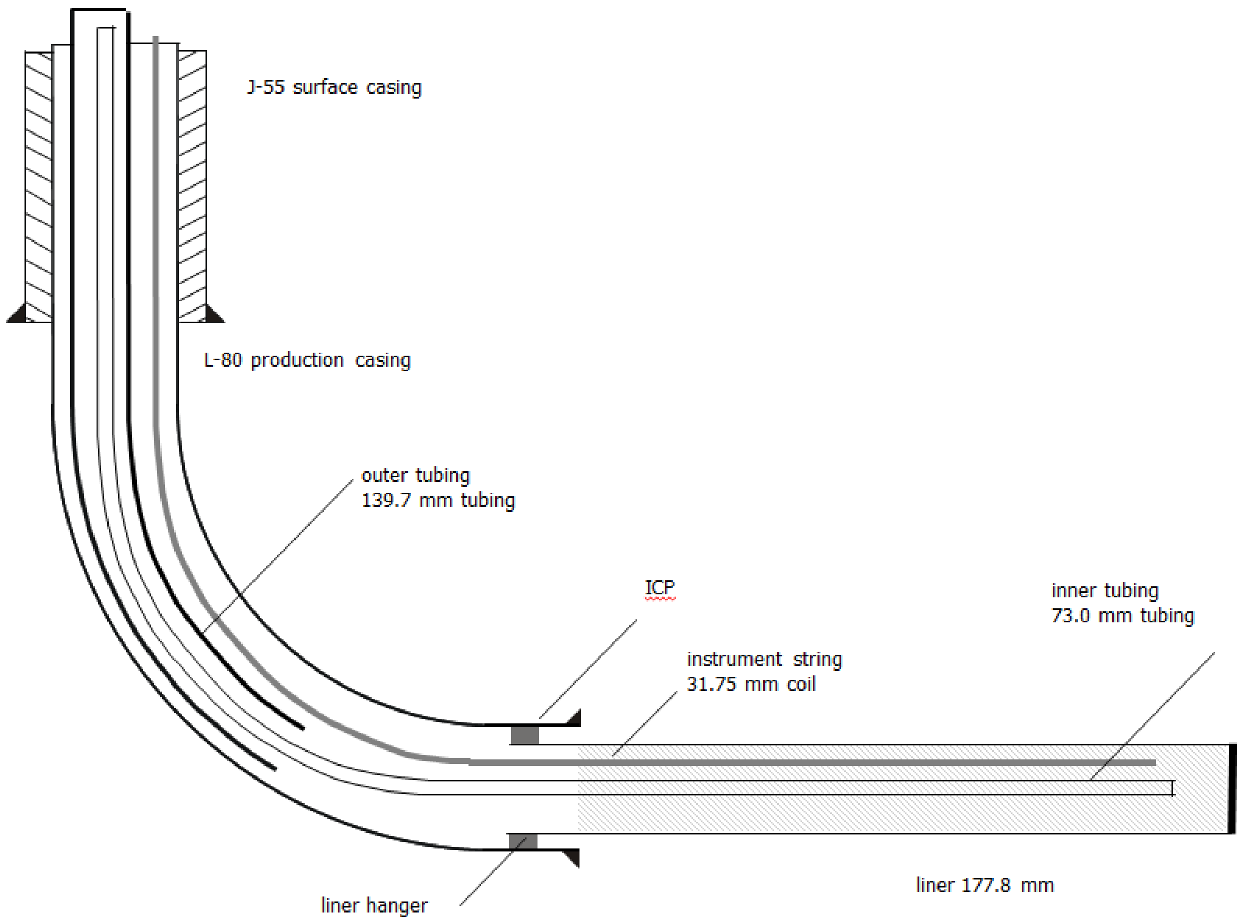
  Reservoir : 5,847 – 5,956 kPa (average gradient 14.3 kPa/m).

  Caprock : 6,030 – 6,527 kPa (average gradient 16.0 kPa/m).



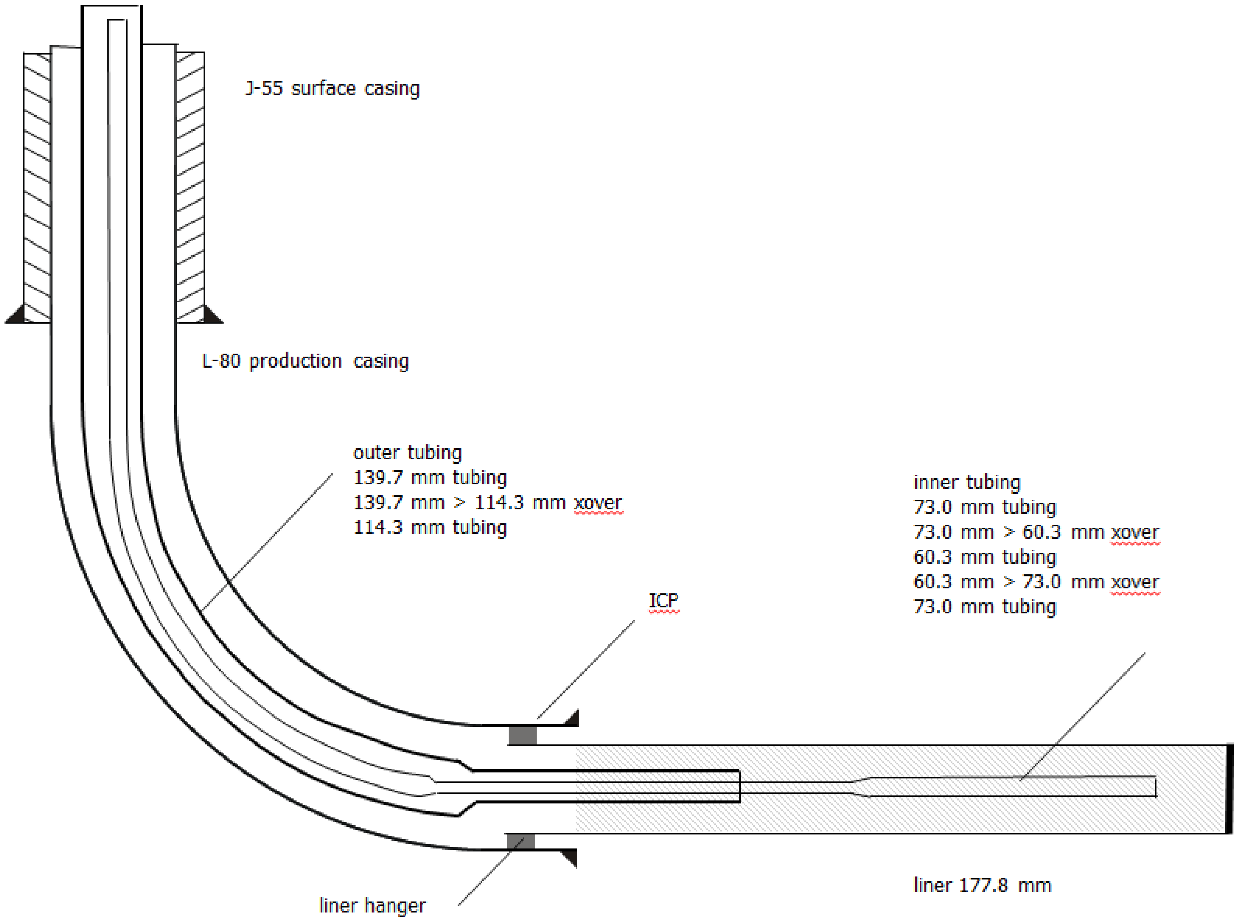
Drilling and Completions

Producer Initial Completion

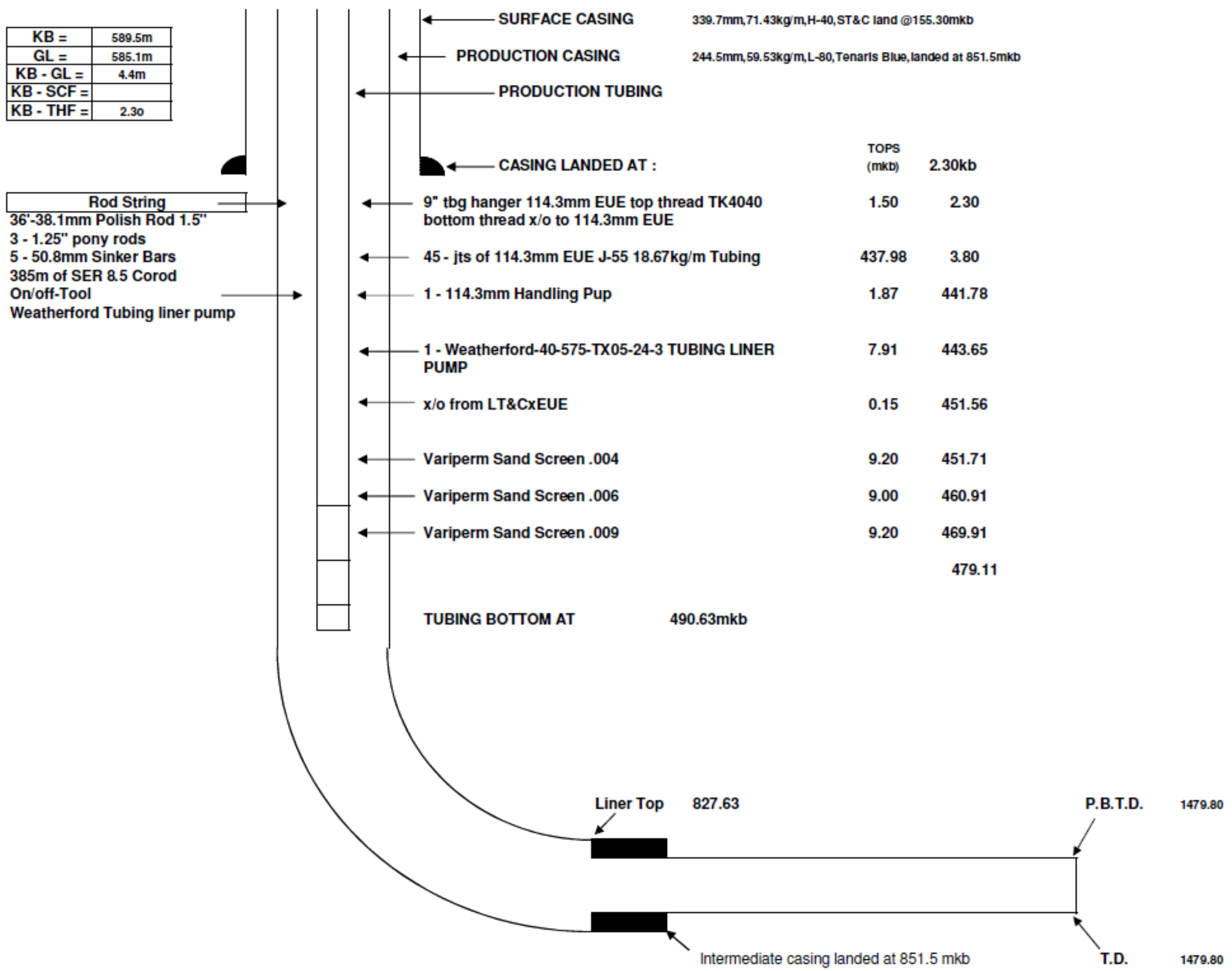


Drilling and Completions

Injector Completion



Pilot Producer Re-Completion (end of Nov 2014)



Artificial Lift

- **Initial Completion – Gas Lift (May 2014 to Nov 2014)**
  - No major issues with performance were observed.
  - Minor issue of undersized flash separator when well slugging.
  - Although gas lift permitted higher peak production rates, it was difficult to achieve stable production due to facility limitations and erosion from fines and sand.
- **Re-completion – Mechanical Pumping System (Weatherford VSH2 & tubing pump from Dec 2014 to Apr 2015)**
  - Reciprocating rod lift system resulted in stable production rates and proved to be easier to operate when stopping and re-starting the well. The thermocouple string was removed to provide enough clearance for the pump. Thermocouple string was operational until its removal.
  - A balanced steaming strategy was followed. Cumulative steam injection balances cumulative produced water. As a result the steam chamber pressure was maintained around 3,900 kPa.
  - Commercial design is based on tubing pump and Rotaflex surface lifting system.

Instrumentation In Well

- Injector:
  - Casing gas blanket for bottom hole pressure measurement.

- Producer:
  - Lift gas blanket for bottom hole pressure measurement.
  - Thermocouple string for bottom hole temperature measurement (Jan 2014-Nov 2014).
  - Thermocouple string removed to make space for mechanical pump (Dec 2014-Apr 2015).

Scheme Performance

- Initial Circulation Phase
  - Established circulation into producer on Jan 24, 2014 and into injector on Feb 13, 2014.
  - Circulated for total of 96 days, 79 operating days with 17 days downtime.
  - Converted to SAGD mode May 1, 2014.
  - Total Injected Steam: 10,836 m^3 (3,858 m^3 into Injector; 6,978 m^3 into Producer).
  - Total water produced back: 11,078 m^3.
  - Reservoir showed good fluid containment.
  - Circulation warm-up strategy showed excellent temperature conformance along the wellbore and allowed excellent production ramp-up.

- SAGD Mode:
  - Production ramped up as expected.
  - Subcools 0 – 10 ^oC (May 2014 – Nov 2014).
  - Balanced injected water/produced water strategy from Dec 2014 to Apr 2015.

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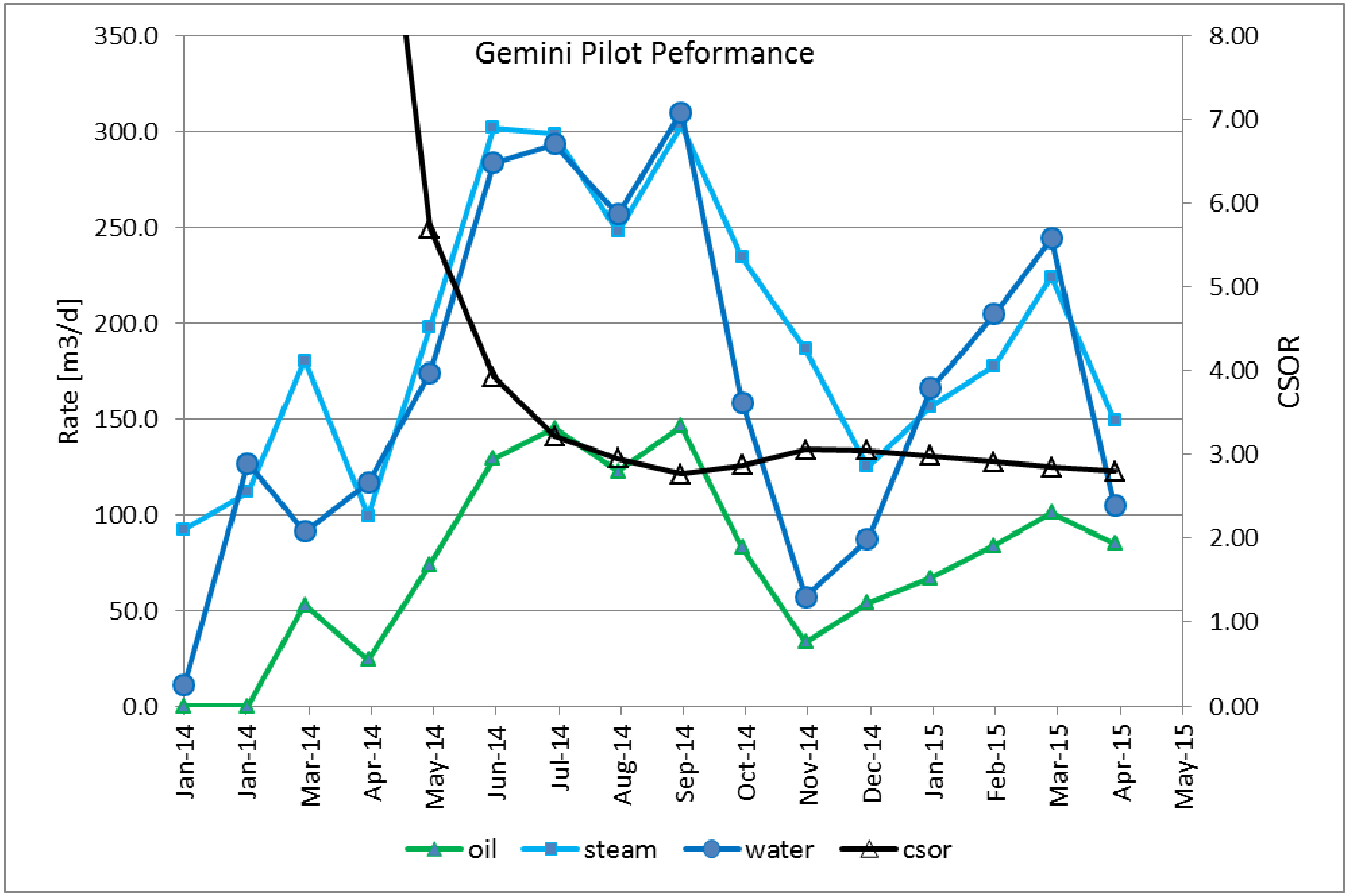
Gemini Pilot Production



Scheme Performance

As of April 30, 2015:

- 32,206 m^3 cumulative oil production
  - OBIP: 600m x 25m x 70m x 0.80 So x 0.33 porosity = 277.2 e^3m^3
  - Recovery Factor: 11.6 %.

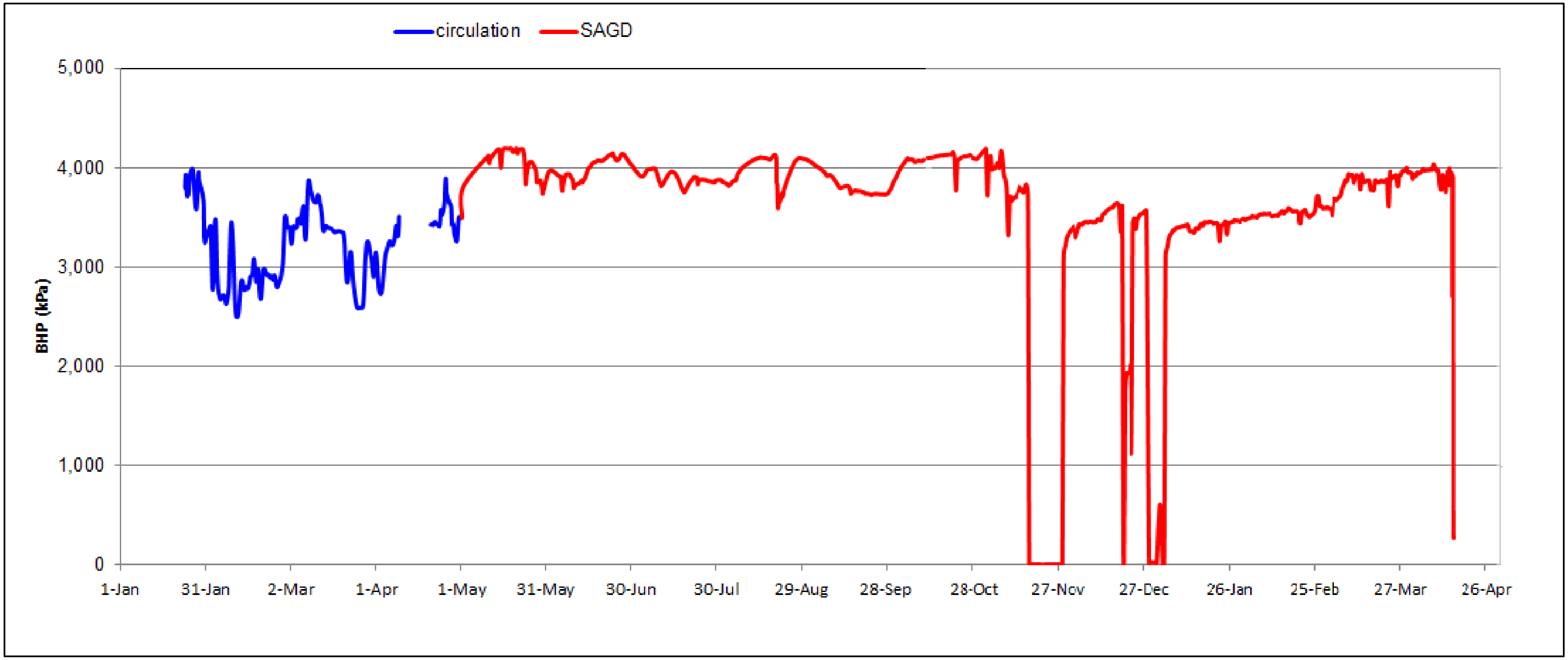
- 2.79 Cumulative Steam Oil Ratio.

- Peak Production Rates
  - Gas Lift: 225 m^3/d (1,413 bopd).
  - Mechanical Lift: 135 m^3/d (848 bopd).

Operating Pressures

- SAGD operating pressure.

Bottomhole Pressures (kPa)



Operating Pressures

- Monthly Average Bottomhole Pressures (kPa).

Jan-14	3,733
Feb-14	2,916
Mar-14	3,272
Apr-14	3,334
May-14	4,001
Jun-14	3,998
Jul-14	3,898
Aug-14	3,980
Sep-14	3,832
Oct-14	4,057
Nov-14	2,286
Dec-14	2,858
Jan-15	3,162
Feb-15	3,551
Mar-15	3,847
Apr-15	3,686

Steam Properties

- Injecting dry steam.
  - 100% wellhead quality, short distance from facility.
- Maximum 4,200 kPag BHP.
  - Steam saturation temperature ~ 253 ^{o}C.

Future Plans

- Evaluating current design and performance for future development:
  - Liner Slot Design
    - While on Gas Lift, facility valves were eroded due to minor sand production when subcool was lowered to 0°C. Also had a sand production event that plugged off a portion of the producer.
    - Cleaned producer, installed wire-wrapped screen on tubing pump. No further sand production measured.
    - Wire-wrapped screen or smaller slot design will be used in the Commercial Project.
  - Mechanical Lifting System
    - Commercial design is based on tubing pump with Rotaflex surface lifting system.

- Project Amendment:
  - Baytex submitted an application in December 2014 to reduce the size of the commercial facility from 1,600 m^3/d to 800 m^3/d.
  - The amendment includes the addition of two new Project & Development Areas (Pod 2 and Pod 3).

Surface

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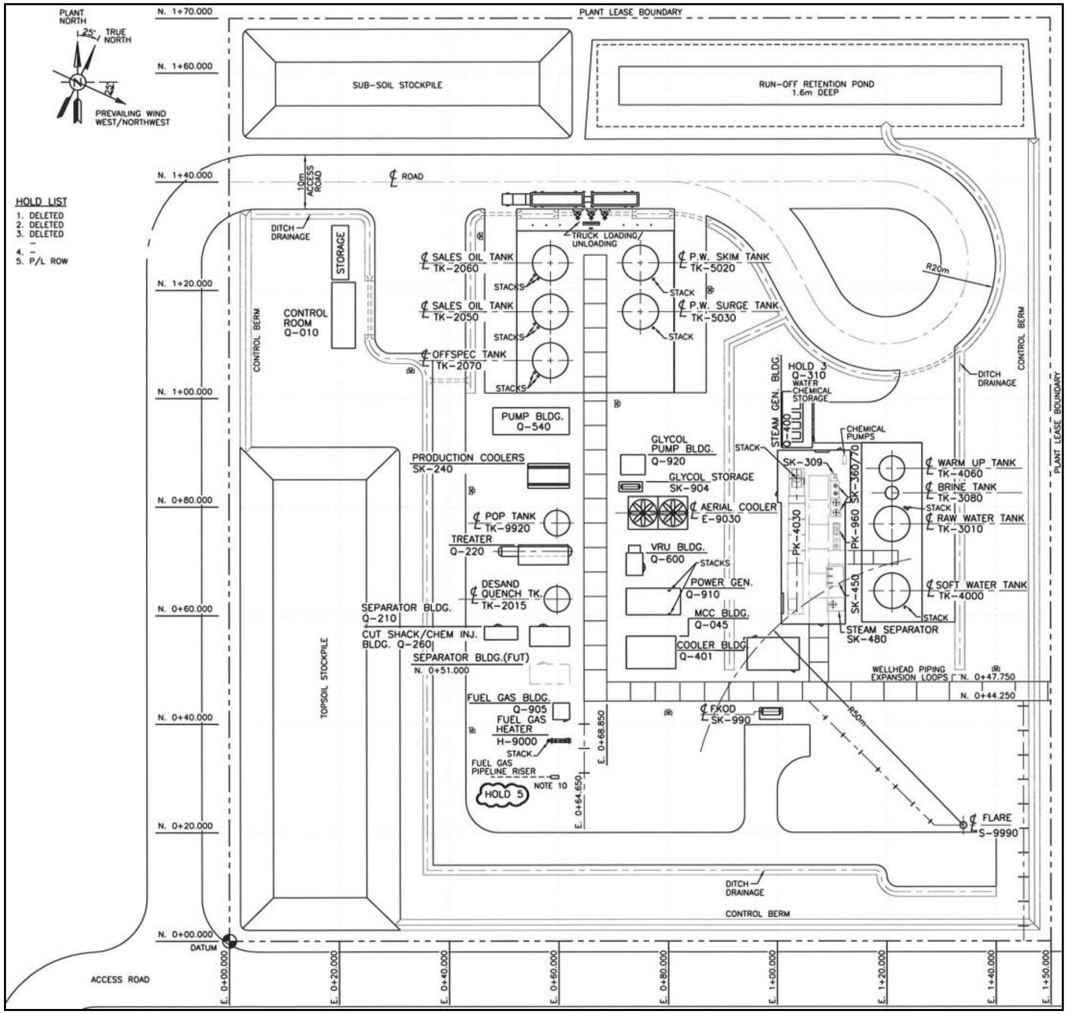
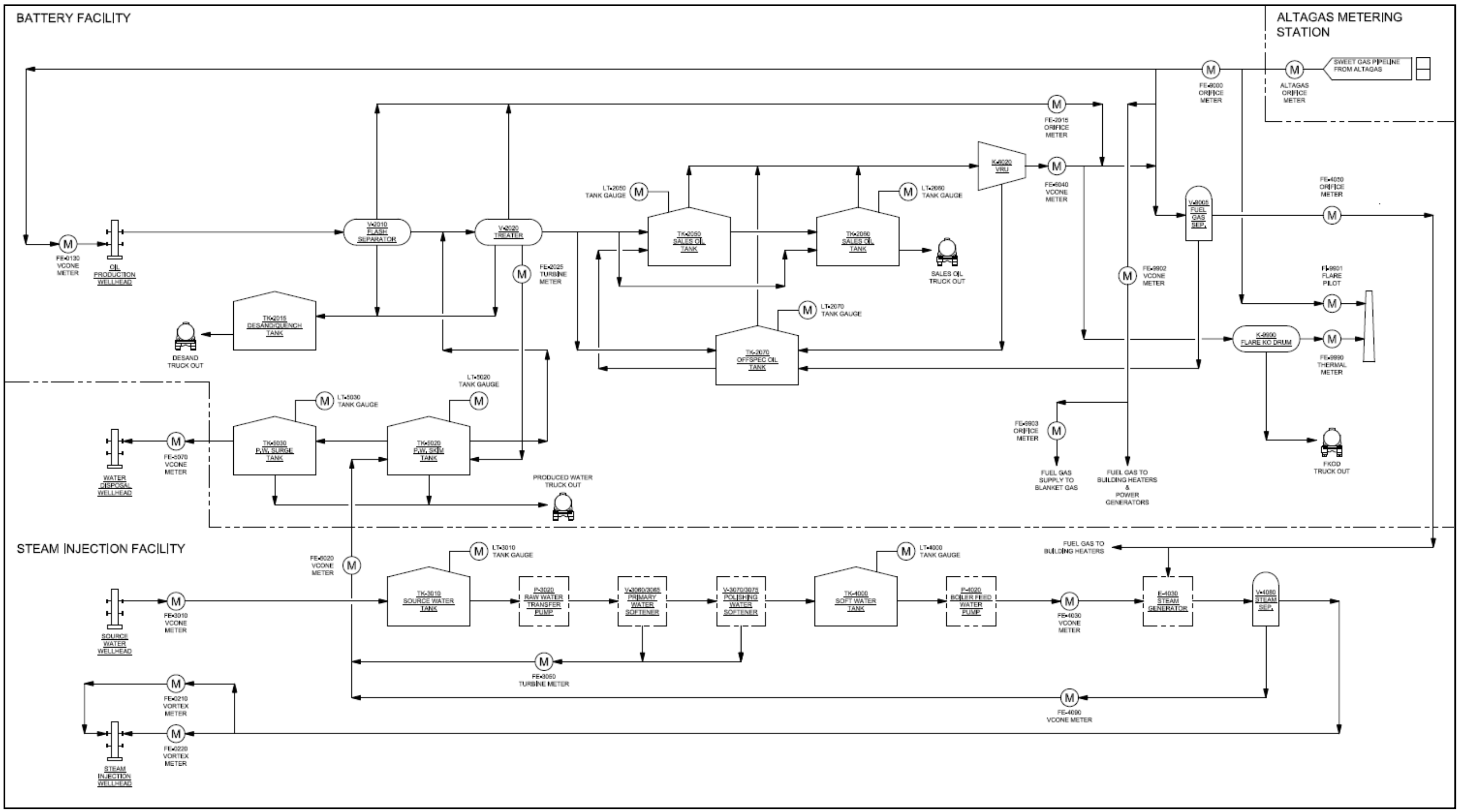
Facilities – SE ¼-14-60-03 W3M Plot Plan



Facility Schematic



Facility Performance

- April 2015 power generator building caught on fire and equipment was damaged beyond repair. Comments below are from last update to time of fire.
- Facility consistently made sales specification oil.
- OTSG consistently makes 75 to 80% quality steam.
- Makeup water treatment uses SAC water softeners and consistently produces BFW specification water.
- 2 x 400 kW power generators with natural gas engine drivers ran consistently.

Facility Performance – Gas

- Gas volumes e^3m^3

Month	Produced Gas	Purchased Gas	Vent Gas	Flare Gas	Solution Gas Recovery %
Aug-14	39.9	919.8	0	0	100
Sep-14	127.7	748.8	0	0	100
Oct-14	80.4	714.16	0	0	100
Nov-14	52.3	572.1	0	0	100
Dec-14	67.7	487.3	0	0	100
Jan-15	62.21	542.6	0	0	100
Feb-15	69.1	534.5	0	0	100
Mar-15	83.4	755.1	0	0	100
Apr-15	31.1	307.4	0	0	100

- Produced gas is recovered and consumed at OTSG.

Gemini Pilot Learnings

- Facilities
  - Demonstrated ability to produce pipeline spec (< 0.5% BS&W) without the use of diluent.
  - Commercial design does not include diluent for treating.

- Production & Recovery Forecast
  - Field data of 600m pilot well pair validated original numerical simulation model (CMG Stars) and this model was utilized to develop the Commercial Project forecast with wells at ~ 750m horizontal length.

Greenhouse Gas

GHG Emissions from Gemini In-Situ Oil Sands Project (Sept. 1, 2014 to Apr. 14, 2015)				
Month	CO_2 (tonnes)	CH_4 (tonnes)	N_2O (tonnes)	CO_2e (tonnes)
02-14-60-03-W4M				
September 2014	1682	0.032	0.031	1692
October 2014	1521	0.029	0.028	1530
November 2014	1195	0.023	0.022	1202
December 2014	1058	0.020	0.019	1064
January 2015	1156	0.022	0.021	1163
February 2015	1160	0.022	0.021	1167
March 2015	1610	0.031	0.029	1620
April 2015 [1]	648	0.013	0.012	652
Total	**10031**	**0.19**	**0.18**	**10090**

- Operations suspended on April 14, 2015.

3) Measurement and Reporting

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Measurement and Reporting

MARP approved May 7, 2013

- Annual update submitted Feb 28, 2014.

Production Volumes

- Single well battery – no proration or well tests required
- Bitumen & Produced Water determined by Dispositions – Inventory Change – Receipts
- Produced Gas: Measured VRU, Treater, and Separator Gas Streams.

Injection Volumes

- Steam: Measured BFW – Blowdown.

Measurement and Reporting – Water Balance

Month	Water Balance %
Aug-14	0.10
Sep-14	1.40
Oct-14	5.80
Nov-14	10.80
Dec-14	0.50
Jan-15	0.40
Feb-15	1.20
Mar-15	3.50
Apr-15	12.70

- Annual MARP meter inspections and calibration as per MARP and Directive 17.
- For November, a measurement review was completed. Meters were recalibrated and problematic (functional, or variance) devices were identified going forward they will require more frequent monitoring and maintenance.
- Variance for April 2015 is attributed to decommissioning activities.

4) Water Production and Usage

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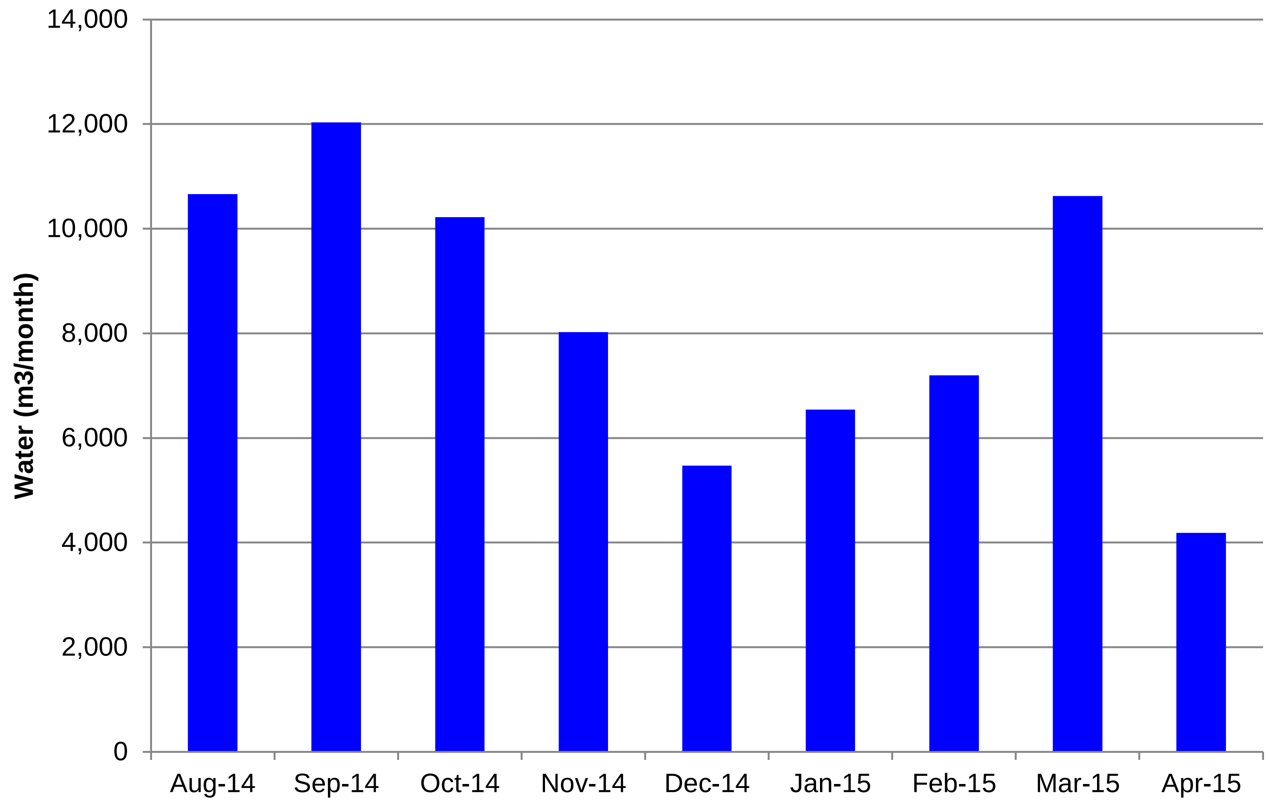
Source Water

- Non Saline water source well.
  - 102/02-14-060-03W4M.
  - License: AB WS 0131002.
- Water sourced from the Empress Channel aquifer.
- Project is a Pilot produced water is not recycled.
- Source Water Quality.
  - 789 ppm TDS as of 2013-01-02.

Source Water Volumes



Water and Steam Volumes

- Produced Water and Steam Injection Volumes (m^3).

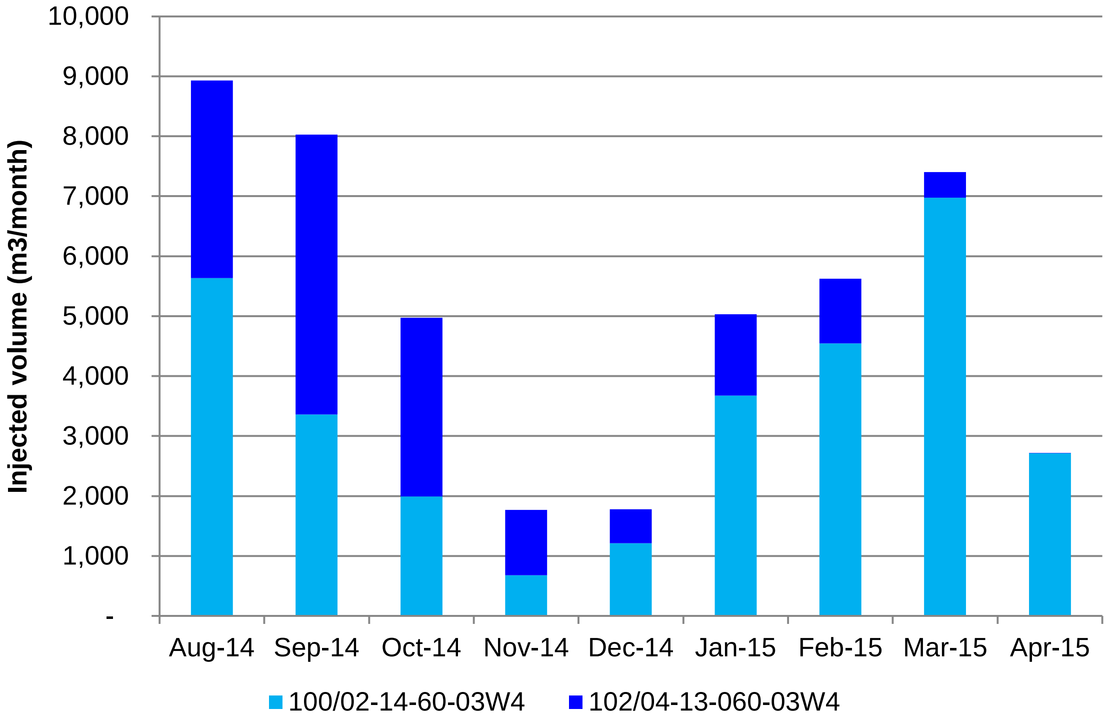
Month	Injected Steam	Produced water
Aug-14	6,870	7,953
Sep-14	9,092	9,295
Oct-14	7,260	4,911
Nov-14	5,587	1,705
Dec-14	3,872	2,691
Jan-15	4,845	5,133
Feb-15	4,966	5,724
Mar-15	6,942	7,566
Apr-15	2,529	3,131

Water and Waste Disposal

- Baytex Gemini 100/02-14-060-03W4. (produced water)
  - Disposing into the Clearwater formation; Approval 12173.
  - Relicensed as Class 1B (Nov 25, 2014).
  - MOP increased to 5,400 kPa (Apr 21, 2015).
  - ABIF 0130103.
  - Injection Pressure 4,300 kPa, Injection Temp 70 ^{o}C.
- Baytex Gemini 102/04-13-060-03W4. (produced water)
  - Disposing into the Clearwater formation; Approval 12288.
  - Class 1B disposal well.
  - MOP increased to 5,400 kPa (May 12, 2015).
  - ABIF 0130103.
  - Injection Pressure 4,300 kPag, Injection Temp 70 ^{o}C.
- Baytex Ardmore 100/15-18-062-3W4/2. (produced water)
  - ABIF 0081235.
- Baytex Ardmore 100/11-18-062-4W4. (produced water)
  - ABIF 0091739.
- Tervita Lindbergh 05-26-056-05W4. (boiler blowdown and regen waste)
  - ABWP 0000557.
- Four Winds Hillmond 04-29-051-26W3. (boiler blowdown and regen waste)
  - SKIF 0005884.

Produced Water Disposal Volumes

- Gemini Pilot uses less than 500,000 m^3 per year of make up water and does not recycle the produced water as per allowance in Directive 081, section 5.



5) Sulphur Production

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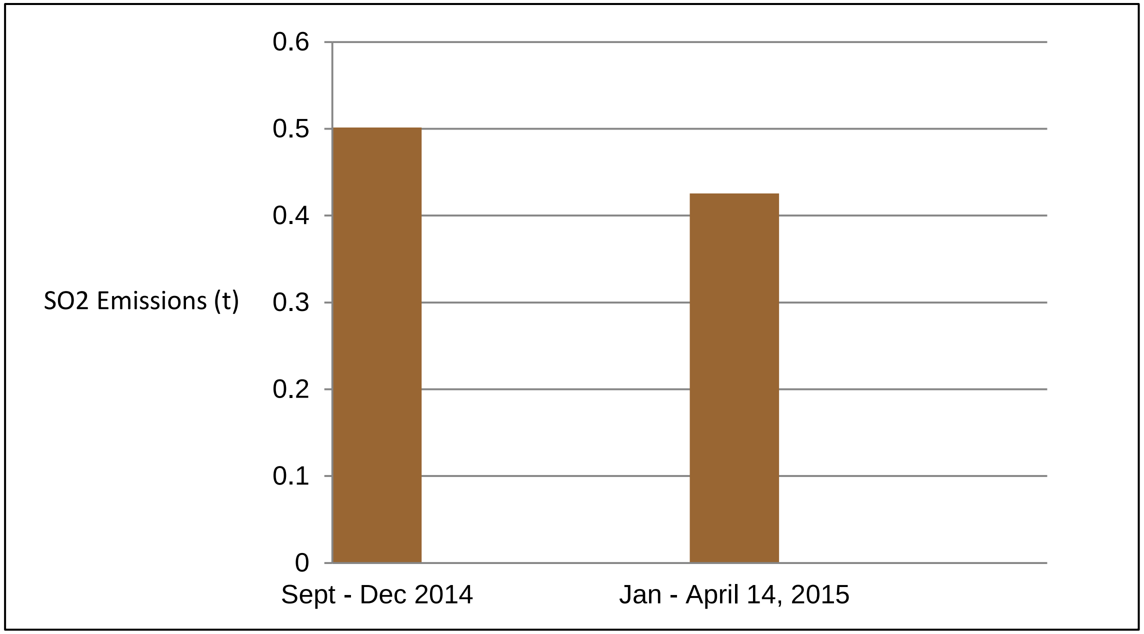
SO_2 Emissions (t) Comparison at Gemini CPF

SO_2 Emissions (t) Comparison at Gemini CPF



Monthly Sulphur Balance[1]

	All Oil Sands Wells on Pad (kg S)	TANK VRU (kg S)	Flared Gas (kg S)	Total Gas from Plant (kg S)	Water Source Well Casing Gas (kg S)	Total Monthly Sulphur emitted (kg S)
Measurement Location	Produced Gas	FE-6040 Gas off V-6040	FE-9990 Gas to Flare	Calculation	FE-2015 WetGasOff V-2010 FlashSep	Calculation
Sep-14	139.8	5.7	0.0	145.5	0.0	145.5
Oct-14	17.1	0.2	0.0	17.2	0.0	17.2
Nov-14	38.4	0.0	0.0	38.4	0.0	38.4
Dec-14	48.4	1.4	0.0	49.8	0.0	49.8
Jan-15	74.4	0.5	0.0	74.9	0.0	74.9
Feb-15	20.5	0.0	0.0	20.5	0.0	20.5
Mar-15	24.2	0.6	0.0	24.8	0.0	24.8
Apr-15[2]	92.9	0.0	0.0	92.9	0.0	92.9

[1] – Sulphur release values are based on metered flowrates and the H_2S content from a gas analysis sample taken from the produced gas effluent stream. The emission estimate assumes 100% of the H_2S is converted into SO_2 and released into the atmosphere.
[2] – Operations suspended on April 14, 2015.

SO_2 Max Daily Emissions (t/d)

- SO_2 emissions: no exceedances of EPEA Approval limit.

	Sep-14	Oct-14	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	EPEA
CPF	0.01	0.0013	0.0043	0.0046	0.0095	0.0027	0.0037	0.0272	0.75

Spills and Clean-Up

- March 27 2015: Crude oil spill from produced water tank during a produced water heat exchanger flush. About 250 liters of oil were released into the on-site drainage ditch. Non-reportable volume.
- Vacuum trucks and bobcat were used to remove the oil.
- Cause was related to very hot water off the treater which caused the fluid to escape out of the pressure vacuum release valve.
- After clean-up, water from the drainage ditch and surface retention pond was laboratory tested. No issues were identified.

Passive Monitoring

- No exceedances of SO_2 concentration objective.

Passive Monitoring Stations Maximum Monthly Concentrations										
		Sep-14	Oct-14	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	AAAQO
H_2S	Pad 1	0.19	0.18	0.22	0.74	1.24	0.65	0.54	0.18	none
SO_2	Pad 1	0.5	0.4	0.5	0.9	1.2	1.7	0.8	0.3	11
AAAQO is an ESRD 30-day objective										
Concentrations are in ppbv										
Data for April only includes the period between April 1-14, 2015.										

- The values collected for H_2S represent a time-weighted average based on the exposure time (1 month). Currently only 1hr and 24hr limits are available for H_2S under the AAAQO guidelines. Data is presented for trend analysis only.

Continuous Air Monitoring

- SO_2, NO_2 and H_2S concentrations (ppbv)

Continuous Monitoring Stations SO_2 Concentrations							
	Sep-14	Oct-14	Nov-14	Dec-14	Jan-15	Feb-15	AAAQO
Max Hourly	10	2	362	11	4	-	172
Max Daily	2.5	0.5	21	1.4	2.3	-	48
Average Monthly	0.3	0.08	0.95	0.43	0	-	11
Continuous Monitoring Stations H_2S Concentrations							
	Sep-14	Oct-14	Nov-14	Dec-14	Jan-15	Feb-15	AAAQO
Max Hourly	4	3	80	4	7	-	10
Max Daily	1.7	0.3	6.1	1.2	1.8	-	3
Continuous Monitoring Stations NO_2 Concentrations							
	Sep-14	Oct-14	Nov-14	Dec-14	Jan-15	Feb-15	AAAQO
Max Hourly	57	27	37	52	64	-	159

- The continuous air monitoring trailer was removed on February 4, 2015 following the fulfillment of the EPEA Approval requirements.
- H_2S and SO_2 exceedances were identified during November 2014.
- A VSD was submitted to the AER as required by the EPEA Approval on Nov 14, 2014.
- Exceedances were due to short flaring events and unusual wind direction.
- Deemed to be an isolate incident and exceedances did not occur again.

Groundwater Monitoring – Thermal Effects

- The Gemini Pilot project was shut down on April 14, 2015. No groundwater monitoring work had commenced for the 2015 groundwater monitoring program. The AER authorized discontinuation of the program on June 2, 2015.

- No major changes occurred between 2014 and 2015 at the Plant and the 2014 groundwater monitoring program did not identify any thermal effects observed on groundwater immediately adjacent to the steam injection wells.

- As there was no observed effect in the monitoring wells, of which some are completed in the Marie Creek Formation, and the Formation is continuous between the steam injection site and Angling lake, there are no expected thermal effects on Angling Lake.

Surface Water (Angling Lake) Monitoring Program

- Domestic well monitoring was conducted in August 2014.
- Results from the sampling at Angling Lake were generally consistent with previous year's data. Angling Lake was not thermally stratified as evidenced by consistent temperatures and dissolved oxygen levels measured at each site and through each depth profile.
- Arsenic values in the lake remain above provincial and federal guidelines, however the concentrations are consistent with historical data and were the lowest observed since 2003.
- Since the SAGD facility commenced in January 2014, the elevated arsenic concentrations would be considered naturally occurring and background values for the area.

Soil Monitoring Program

- 2014 soil monitoring was completed in September 2014.
- All analyzed parameters were within applied guidelines with the exception of SS14-01 (surface stain on the well pad). This area was subsequently remediated to within applied guidelines.

Regulatory Summary

Authorizations and Approvals:

- Approval was received from the AER to increase injection pressure at two disposal wells.
- Well 00/02-14-060-03W4/0: Class 1b Disposal Approval No. 12173C.
- Well 02/04-13-060-03W4/0: Class 1b Disposal Approval No. 12288A.
- The need for increased injection pressure was due to an anticipated increase in produced water volumes.

Regulatory Summary (continued)

Voluntary Self Disclosure (VSD):

- H_2S and SO_2 exceedances were identified during November 2014.
- A VSD was submitted to the AER as required by the EPEA Approval on Nov 14, 2014.
- Exceedances were due to short flaring events and unusual wind direction.
- Deemed to be an isolate incident and exceedances did not occur again.

Power Generation Failure - April 14, 2015

- Cause of failure was scoring of engine cylinder liner allowing engine crank case to over pressure.
- Failure occurred just prior to routine maintenance work being initiated to address cylinder liner damage.
- Root cause analysis determined engine #2 sprayed oil from dipstick onto exhaust manifold of engine #1.
- Oil combusted and roof and wiring ignited within seconds Operator initiated emergency shutdown of the power generator and SAGD facility.
- Fuel gas to facility was blocked in.
- Operator extinguished building fire using handheld extinguishers.
- AER was notified the same day.
- The Plant has been shut down since April 14, 2015.

Status of Environmental Monitoring Programs

- On April 27th , 2015 Baytex submitted a letter to the AER to notify of the Pilot's discontinuation and formally requesting suspension of the ongoing environmental monitoring programs required by the EPEA Approval.
- An AER authorization letter was received on June 2, 2015 removing the monitoring and reporting requirements associated with air, groundwater and soil monitoring as well as the *Water Act* diversion license.
- An annual report for any monitoring program work conducted in 2015 until the shut down of the pilot project is still required.
- Industrial runoff monitoring and reporting continues.

Compliance

- To the best of our knowledge, the Baytex Gemini SAGD Project is currently in compliance with all conditions of its approvals, as amended, and associated regulatory requirements.

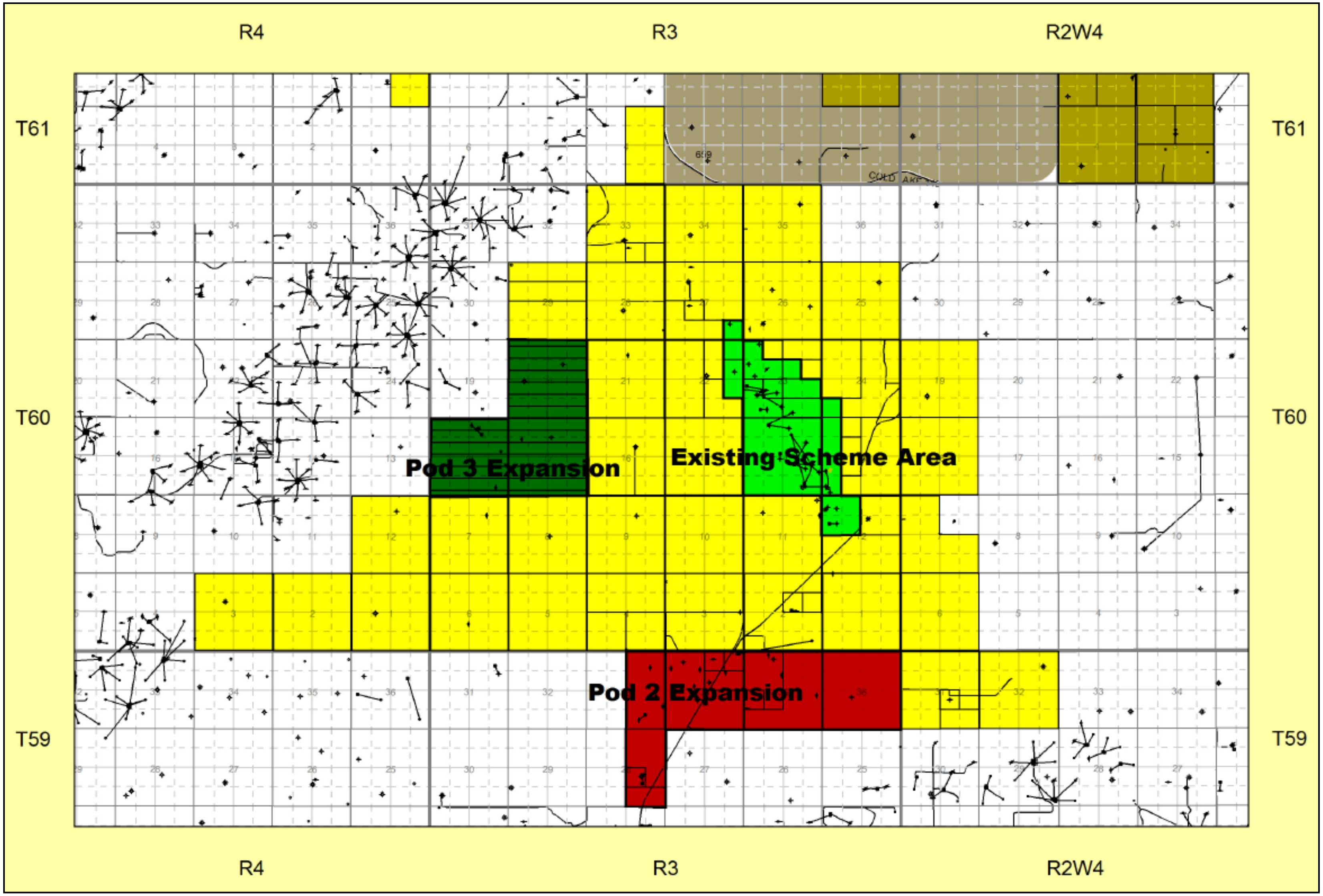
Decommissioning Plans

- As per EPEA Approval (#261830-00-02) Baytex plans to submit a decommissioning and reclamation plan to the AER within six months of the shut down date (plan will be submitted by October 14, 2015).
- The plan will address all elements of the Stage 1 Project that will not be used during the development and operation of the Stage 2 Commercial Project. Those elements that are not required will ultimately be fully decommissioned and reclaimed.
- Fuel gas flowline and meter station, water source wells, disposal wells and the SAGD well pair will be used in the commercial operations.
- It is currently anticipated that the decommissioning and reclamation of the Pilot Project will occur once the Commercial Project is sanctioned and construction has commenced.
- At this time Baytex is unable to provide a definitive schedule for this decommissioning and reclamation work as corporate sanctioning for the Commercial Project will not happen until the Project's amendment application has been approved and the commodity price has recovered and stabilized to a point where the project economics are sound.

Future Plans

- Scheme Amendment:
  - Baytex Submitted an Amendment Application to reduce the size of the facility from 1,600 m^3/d to 800 m^3/d.
  - The Amendment also includes the addition of Project Areas (Pod 2 and Pod 3) as shown on the next slide.
- Commercial Phase:
  - Baytex plans to proceed with 800 m^3/d Commercial Project pending an appropriate commodity price environment and capital availability.

Future Plans – Project Area Addition



Advisory

Forward-Looking Statements

In the interest of providing interested parties with information regarding Baytex, including management's assessment of Baytex's future plans and operations, certain statements made by the presenter and contained in these presentation materials (collectively, this "presentation") are "forward-looking statements" within the meaning of the United States Private Securities Litigation Reform Act of 1995 and "forward-looking information" within the meaning of applicable Canadian securities legislation (collectively, "forward-looking statements"). The forward-looking statements contained in this presentation speak only as of the date of this presentation and are expressly qualified by this cautionary statement. The information contained in this presentation does not purport to be all-inclusive or to contain all information that potential investors may require.

Specifically, this presentation contains forward-looking statements relating to, but not limited to: our business strategies, plans and objectives; and our Gemini SAGD Pilot Project, including development and operational plans, completion strategies, our assessment of the performance of the project, our interpretation of geology, project life, original bitumen in place volumes, expected recovery factors and steam-oil ratios, the annual volume of make up water used by the project, and our application to amend the currently approved project. In addition, information and statements relating to reserves are deemed to be forward-looking statements, as they involve implied assessment, based on certain estimates and assumptions, that the reserves described exist in quantities predicted or estimated, and that the reserves can be profitably produced in the future.

Although Baytex believes that the expectations and assumptions upon which the forward-looking statements are based are reasonable, undue reliance should not be placed on the forward-looking statements because Baytex can give no assurance that they will prove to be correct.

These forward-looking statements are based on certain key assumptions regarding, among other things: petroleum and natural gas prices and pricing differentials between light, medium and heavy gravity crude oils; well production rates and reserve volumes; capital expenditure levels; the receipt, in a timely manner, of regulatory and other required approvals for our operating activities; the availability and cost of labour and other industry services; interest and foreign exchange rates; the continuance of existing and, in certain circumstances, proposed tax and royalty regimes; our ability to develop our crude oil and natural gas properties in the manner currently contemplated; and current or, where applicable, proposed assumed industry conditions, laws and regulations will continue in effect or as anticipated. Readers are cautioned that such assumptions, although considered reasonable by us at the time of preparation, may prove to be incorrect.

Actual results achieved will vary from the information provided herein as a result of numerous known and unknown risks and uncertainties and other factors. Such factors include, but are not limited to: declines in oil and natural gas prices; risks related to the accessibility, availability, proximity and capacity of gathering, processing and pipeline systems; uncertainties in the credit markets may restrict the availability of credit or increase the cost of borrowing; refinancing risk for existing debt and debt service costs; a downgrade of our credit ratings; risks associated with properties operated by third parties; changes in government regulations that affect the oil and gas industry; changes in environmental, health and safety regulations; variations in interest rates and foreign exchange rates; risks associated with our hedging activities; the cost of developing and operating our assets; risks associated with the exploitation of our properties and our ability to acquire reserves; changes in income tax or other laws or government incentive programs; uncertainties associated with estimating petroleum and natural gas reserves; risks associated with acquiring, developing and exploring for oil and natural gas and other aspects of our operations; risks associated with large projects or expansion of our activities; risks related to heavy oil projects; the implementation of strategies for reducing greenhouse gases; depletion of our reserves; risks associated with the ownership of our securities, including the discretionary nature of dividend payments and changes in market-based factors; risks for United States and other non-resident shareholders, including the ability to enforce civil remedies, differing practices for reporting reserves and production, additional taxation applicable to non-residents and foreign exchange risk; and other factors, many of which are beyond our control. These and additional risk factors are discussed in our Annual Information Form, Annual Report on Form 40-F and Management's Discussion and Analysis for the year ended December 31, 2014, as filed with Canadian securities regulatory authorities and the U.S. Securities and Exchange Commission.

Advisory (Cont.)

Readers are cautioned that the foregoing list of risk factors is not exhaustive. New risk factors emerge from time to time, and it is not possible for management to predict all of such factors and to assess in advance the impact of each such factor on our business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statements.

The above summary of assumptions and risks related to forward-looking statements in this presentation has been provided in order to provide potential investors with a more complete perspective of our current and future operations and such information may be not appropriate for other purposes. There is no representation by Baytex that actual results achieved will be the same in whole or in part as those referenced in the forward-looking statements and Baytex does not undertake any obligation to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise, except as may be required by applicable securities law.

Oil and Gas Information

The determination of oil and gas reserves involves the preparation of estimates that have an inherent degree of associated uncertainty. Categories of proved and probable reserves have been established to reflect the level of these uncertainties and to provide an indication of the probability of recovery. The estimation and classification of reserves requires the application of professional judgment combined with geological and engineering knowledge to assess whether or not specific reserves classification criteria have been satisfied. Knowledge of concepts, including uncertainty and risk, probability and statistics, and deterministic and probabilistic estimation methods, is required to properly use and apply reserves definitions.

The recovery and reserves estimates described herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual reserves and future production from such reserves may be greater or less than the estimates provided herein. The estimates of reserves for individual properties may not reflect the same confidence level as estimates of reserves for all properties, due to the effects of aggregation. For complete NI 51-101 reserves disclosure, please see our Annual Information Form for the year end December 31, 2014 dated March 9, 2015.

When converting volumes of natural gas to oil equivalent amounts, Baytex has adopted a conversion factor of six million cubic feet of natural gas being equivalent to one barrel of oil, which is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Oil equivalent amounts may be misleading, particularly if used in isolation.

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