MEG ENERGY

September 30, 2020

Alberta Energy Regulator
Suite 1000, 250 – 5th Street SW
Calgary, AB T2P 0R4

Attention: Jon Keeler. P.Eng.
Manager, In Situ Subsurface, Regulatory Applications

Subject: MEG Energy Corp. Christina Lake Regional Project AER
Commercial Scheme Approval No. 10773
2019/2020 Directive 54 Performance Report

Dear Mr. Keeler,

MEG Energy Corp. (MEG) hereby submits the 2019/2020 Annual Performance Report for the Christina Lake Regional Project (CLRP) under Directive 54: Performance Reporting and Surveillance of In Situ Oil Sands Schemes. The operating period covered by this performance report is from May 1, 2019 to April 30, 2020.

Please feel free to contact me at (403) 781-1027 should you have any additional information needs.

Yours truly,

Sachin Bhardwaj
Regulatory Manager

Christina Lake Regional Project
2019/2020 Directive 54 Performance Report

Alberta Energy Regulator
Commercial Scheme Approval No. 10773

SUBMITTED TO:

Alberta Energy Regulator

SUBMITTED BY

MEG Energy Corp.

TABLE OF CONTENTS

TABLES

FIGURES

1 INTRODUCTION

1.1 Background

MEG Energy Corp. (MEG) is a public Calgary-based energy company focused on sustainable in situ thermal oil production and the generation of power in the southern Athabasca region of Alberta, Canada. MEG operates the Christina Lake Regional Project (CLRP) located in Townships 76 to 78 and Ranges 4 to 6, West of 4th Meridian, which utilizes steam-assisted gravity drainage (SAGD) technology to extract bitumen from the oil sands. The following is a summary of the CLRP operating history broken down by phase:

Phase 1

- Approved in February 2005 for bitumen production of 477 cubic meters per day (m^3/d) or 3,000 barrels per day (bbl/day)
- Sustained steaming commenced March 2008

Phase 2

- Approved in March 2007 for total production of 3,975 m^3/d or 25,000 bbl/day
- First steam Q3 2009

Phase 2B

- Approved in March 2009 for total production of 9,540 m^3/d or 60,000 bbl/day
- First steam Q3 2013

Phases 3A/B/C/D

- Approved in February 2012 for total production of 33,390 m^3/d or 210,000 bbl/day

Phase 2B4X

- Approved in June 2014 to re-locate Phase 3B to Phase 2/2B central processing facility (CPF)

The CLRP operates under the Alberta Energy Regulator (AER) administered Oil Sands Conservation Act (OSCA) Commercial Scheme Approval No. 10773 and the Environmental Protection and Enhancement Act (EPEA) Approval No. 216466-01-04.

In 2019, average daily bitumen production was 93,082 bbl/day with a steam-oil-ratio (SOR) of 2.22. In the first quarter of 2020, average daily bitumen production was 91,557 bbl/day with an SOR of 2.31. Bitumen production in the first quarter of 2020 was impacted by a combination of extreme cold weather in January, scheduled planned maintenance activities in February and implementation of the COVID-19 response plan in March which resulted in a significant reduction in operating personnel on site. Additionally, voluntary price-related production curtailments were implemented in April in response to the decrease in commodity prices.

2 SUBSURFACE

2.2 Production Plot

An annotated scheme-level lifespan production plot for the CLRP is shown on Figure 1.

2.3 Development Area Maps

Updated development area maps are provided as follows:

- Figure 2 – Drilled and approved drainage pattern areas
- Figure 3 – Net pay isopach
- Figure 4 – Associated gas in communication with pay
- Figure 5 – Net basal water isopach in communication with pay
- Figure 6 – Seismic acquisition in the project area

There are no known geomechanical anomalies in the development area.

2.4 Representative Cross Section

An updated representative cross section within the active development area containing formation tops, pay intervals, and associated gas and water intervals is provided in Figure 7.

2.5 Resources

Table 1 provides Original Bitumen in Place (OBIP) and cumulative bitumen production for the project, development, and combined active well pattern areas. Table 2 presents the typical reservoir parameters within the development area.

Table 1. OBIP and cumulative bitumen production

Area	OBIP* (bbl)	Cum Oil Prod** (bbl)	Cum Recovery (%)
Project Area	4,211,690,000	234,014,815	6%
Development Area	2,228,813,000		10%
Combined Active Well Pattern Area	701,106,000		33%

*Minimum Reservoir thickness of 10m
** As of April 30, 2020
Resource values presented are based on MEG volumetric calculations and are not in accordance with National Instrument 51-101 guidelines

Table 2. Typical reservoir parameters within the development area

Development area Reservoir Parameters	
Average Pay Height (m)	19.5
Pay Porosity range (fraction)	0.27-0.36
Pay Water Saturation range (fraction)	0.15-0.40
Average K_h (Darcies)	5.0
Average K_v (Darcies)	2.5
Initial Reservoir Pressure (kPag)	2,100
Reservoir temperature (°C)	13

2.6 Well Patterns

A table of well patterns that includes various reservoir and resource recovery parameters can be found in Table 3.

Table 3. CLRP Well Pattern Reservoir Parameters, Bitumen In Place and Recovery Factor Estimates

Pattern	Area (m2)	Net Pay Thickness (m)	Average Porosity	Average Oil Saturation	OBIP (m3)	SBIP (m3)	Recovery to Date (% OBIP)	Estimated Ultimate Recovery (%OBIP)	Recovery to Date (% SBIP)	Estimated Ultimate Recovery (%SBIP)
A	698,812	21.7	32.5%	76.2%	3,752,000	3,501,000	58%	60%	62%	64%
Phase 2*	2,690,534	24.1	32.7%	78.4%	16,613,000	14,342,000	63%	63%	72%	73%
V	650,137	25.9	31.6%	73.7%	3,926,000	3,479,000	31%	~50%	35%	50-60%
G**	215,631	17.6	31.4%	73.0%	876,000	843,000	37%	50-60%	38%	50-60%
H**	66,813	19.1	32.6%	71.5%	298,000	228,000	41%	50-60%	53%	60-70%
J	781,677	21.1	32.7%	74.1%	3,999,000	3,653,000	21%	~50%	22%	50-60%
K**	671,130	16.7	33.1%	73.9%	2,740,000	2,545,000	47%	50-60%	50%	60-70%
M	978,051	29.1	31.9%	79.1%	7,186,000	6,654,000	48%	60-70%	52%	60-70%
N	970,951	23.8	32.6%	79.8%	6,009,000	5,657,000	39%	50-60%	41%	60-70%
T	779,449	15.0	32.0%	82.0%	2,970,000	2,550,000	35%	50-60%	41%	60-70%
U	521,939	19.0	30.0%	80.0%	2,414,000	2,033,000	40%	50-60%	47%	60-70%
AP South	246,044	23.0	33.2%	79.1%	1,485,000	1,362,000	35%	60-70%	38%	60-70%
AF	498,601	19.9	32.4%	81.4%	2,609,000	2,110,000	37%	50-60%	46%	60-70%
AG	414,226	21.5	32.7%	76.7%	2,235,000	2,095,000	29%	50-60%	31%	50-60%
AN	792,929	22.6	32.7%	80.9%	4,744,000	4,165,000	53%	60-70%	60%	70-80%
P	1,269,292	19.7	31.0%	74.7%	5,802,000	4,864,000	27%	50-60%	32%	60-70%
AQ	856,060	19.4	33.3%	79.8%	4,404,000	3,935,000	22%	60-70%	24%	70-80%
AT	972,328	22.1	31.1%	77.8%	5,188,000	4,512,000	17%	50-60%	19%	60-70%
L	946,760	21.4	33.0%	72.7%	4,859,000	4,165,000	14%	50-60%	16%	60-70%
DB	1,218,688	21.3	32.9%	67.6%	5,777,000	4,718,000	8%	50-60%	10%	60-70%
DC	1,025,120	24.2	31.6%	72.3%	5,666,000	4,850,000	2%	50-60%	2%	60-70%
DD	1,420,710	25.4	32.3%	69.2%	8,072,000	6,376,000	2%	50-60%	3%	60-70%

The thickness, porosity and saturation pertain to the Original Bitumen in Place (OBIP). SBIP = SAGDable Bitumen in Place

*Phase 2 includes B, C, D, E and F well patterns

**Does not include inventory wells that have not been started and offline wells due to early life operational issues.

2.7 Co-Injection

Figure 8 shows all the wells at CLRP by injection type. Co-injection of non-condensable gas (NCG) and steam is a critical part of MEG's enhanced Modified Steam and Gas Push (eMSAGP) technology. The eMSAGP technology combines the use of midlife infill wells and NCG injection to reduce the energy or SOR required to extract the remaining bitumen, freeing up steam for deployment to new well pads. This process is implemented after sufficient energy has been stored in the reservoir by the SAGD process and the remaining recoverable bitumen is warm and mobilized. The steam and gas mixture pushes mobilized bitumen to the infill well while continuing to heat the remaining bitumen in place, resulting in increased bitumen production rates at a reduced SOR. As bitumen rates decline, steam injection is reduced to further improve the SOR and NCG injection rates are increased to maintain chamber pressure.

The timing and performance of the extraction processes used at MEG are detailed below. Figure 9 shows the instantaneous SOR (iSOR), NCG injection concentration, and cumulative SOR (cSOR) performance for MEG's Phase 1, Phase 2, and Phase 2B well patterns.

1. SAGD: Initially bitumen is extracted using the SAGD process, with only small amounts of blanket gas injection for bottom-hole pressure measurement and injector insulation. During SAGD, well patterns typically operate with an iSOR of 2.25 to 3.25, depending on the reservoir parameters and quality of the resource. This process is continued until sufficient energy has been stored in the unrecovered bitumen between the original SAGD pairs, and the eMSAGP process is then implemented.

2. eMSAGP: During the eMSAGP phase, infill production is added to the well pattern, steam injection is reduced, and NCG injection rates are increased, resulting in significant iSOR improvement. As steam cuts progress, chamber pressures are returned to near the initial reservoir conditions and NCG is added as required to maintain this pressure. This approach improves the thermal efficiency of the extraction process as NCG replaces the steam required to maintain the chamber pressure while also accumulating at the top of the reservoir, creating an insulating layer that reduces overburden heat losses. NCG concentrations begin at very low levels and increase with time as steam rates are reduced. Well pattern typically have an average iSOR between 1.25 and 1.75 during the eMSAGP phase.

3. Gas Injection Only: Late life wells are converted to NCG injection-only operation to further improve the iSOR. The timing of this stage varies with reservoir quality and performance

The use of NCG co-injection in concert with the use of infill wells in the eMSAGP process has had primarily positive benefits. Production rates and ultimate reservoir recovery have not been impaired by NCG co-injection to date. The SOR reductions achieved using this technology provide significant economic and environmental advantages. Lower steam requirements reduce the per-barrel operating costs as well as the greenhouse gas intensity and water withdrawal intensity. Additionally, the ability to free up steam capacity from operating wells for re-deployment to new wells decreases the capital requirements to increase production. There have been few negative impacts observed, but NCG co-injection results in increased produced gas rates as most of the injected gas is produced back from the reservoir. Consequently, additional gas sweetening units or re-compression packages may be required to treat the additional gas for re-injection or use in steam generation equipment.

3 SURFACE

3.8 Infrastructure and Operations

Figures 10 is a map of the development area that includes constructed and planned surface infrastructure. Figures 11 is a map of the development area that shows all current source and disposal wells. At this time, there are no new source or disposal wells planned. There have been no modifications to the central processing facility over the reporting period that have required an AER approval. Figures 12 and 13 present the annual operational bitumen and steam rates relative to design rates, respectively. Bitumen production performance over the original design is primarily due to operation with naphtha diluent and equipment design factors. Steam performance over original design is primarily due to increased reliability and debottlenecking of fired equipment.

4 HISTORICAL AND UPCOMING ACTIVITY

4.9 Suspension and Abandonment

In the 12-month reporting period, 4 SAGD production wells, 1 SAGD injection well and 7 infill production wells were suspended. No wells or well patterns were abandoned, and no well patterns were in active blowdown within the development area. Table 4 presents a list well that have been suspended over the reporting period. At CLRP there are currently no well patterns that have been suspended or abandoned.

Table 4. List of wells with license statuses that were changed to suspended

Pattern	Well	UWI	Well Licence Number	Licence Status
A	A2P	02/01-13-077-06W4/0	351524	Suspended
	A3N	15/01-13-077-06W4/0	456260	Suspended
BB+D7	BB4P	03/08-21-077-05W4/0	374885	Suspended
	B6N	04/01-21-077-05W4/0	445272	Suspended
E+F1	E1N	09/09-16-077-05W4/0	449523	Suspended
	E4N	12/09-16-077-05W4/0	449526	Suspended
	E5N	08/16-16-077-05W4/0	449527	Suspended
V	V5N	13/02-20-077-05W4/0	460577	Suspended
	V6P	10/02-20-077-05W4/0	438778	Suspended
H	H2I	03/14-04-077-05W4/0	426279	Suspended
	H2P	07/11-04-077-05W4/0	426300	Suspended
P	P9N	06/03-33-076-05W4/0	485027	Suspended

4.10 Regulatory and Operational Changes

Over the reporting period, the focus at the CLRP has been on sustained production and streamlining regulatory requirements. Table 5 lists the regulatory approvals received for the CLRP over the reporting period.

Table 5. List of regulatory approvals over the reporting period

Application number	Description	Approval Date
1924744	Temporary variance from Interim Directive 2001-03	18-Oct-2019
1927492	Amendment application for subsurface modifications to patterns AH and DD	10-Mar-2020
013-216466	Amendment application to exempt cogeneration NOx emission limits during start-up and shutdown periods	21-Apr-2020
1927432	Amendment application for the inclusion of a maximum operating pressure (MOP) clause and submission of a caprock integrity study	10-Jun-2020

There have been no events over the reporting period that could materially affect scheme performance or energy or material balances. The following are some successes at the CLRP:

- Modified the level setpoint on the Phase 2B sales oil tanks resulting in a reduction in pressure excursions in these tanks
- Change in oil in water measurement technique to enhance oil removal equipment
- Implemented separate disposal systems for boiler blowdown and produced water to enhance water recycle options
- HP steam distribution system overall control and protection system modifications in process of being implemented
- Thermal imaging of steam generation equipment ongoing to provide information on condition of tubes

Some issues that were addressed at the CLRP over the reporting period include:

- Modifications to Phase 2 skim tank to allow trialing of online solids removal
- Implementation of Advanced Process Control trial for Phase 2B (free water knockout) FWKO and Treater interface control

Some issues that will be addressed at the CLRP over the next reporting period include:

- Investigating options for data analytics and Advanced Process Control
- Continued optimization of the chemical treatment program

There have been no major technical innovations at the CLRP over the reporting period. The eMVAPEX pilot will be addressed in a separate performance report.

4.11 Regulatory Compliance

To the best of MEG's knowledge, the Christina Lake Regional Project is in compliance with all conditions and regulatory requirements related to Commercial Scheme Approval No. 10773 and EPEA Approval No. 216466-01-04. For the period of May 1, 2019 to April 30, 2020, MEG Energy has no unaddressed non-compliant events.

MEG continues to conduct air, surface water, wetland, groundwater, soil, wildlife and vegetation monitoring proactively and in accordance with approval conditions. The compliance summary for the reporting period is broken down by flaring events, reportable spills, voluntary self disclosures, contraventions, and corresponding efforts in the following tables. All the information provided below has been previously communicated to the AER and is publicly available.

Table 6. Reportable flaring events over the reporting period

AER ID	Date	Est. Volume (e3m3)	Est. Duration (hrs)	H_2S Conc (ppm)	Reason	Details
1209798	2019-05-15	65.6	3	700	Emergency	2B-T-300 boiler feed water (BFW) tank level transmitter spiked a false low reading tripping the BFW pump
1234223	2019-07-15	14.1	4	900	Emergency	Phase 2B gas turbine generator (GTG) trip resulted in flaring
1248313	2019-07-25	82.5	4	600	Emergency	Phase 2B steam plant tripped due to high vibration tripping resulted in flaring
1253095	2019-08-06	137.6	5	850	Emergency	E pad module failure which caused once trough steam generators (OTSG) to trip
1254029	2019-08-06	16.6	6	150	Emergency	E pad module failure which caused OTSG's to trip
1604973	2019-08-23	21	5	230	Emergency	Emergency shutdown (ESD) trip at PH1/PH2 caused excess gas to be flared until plant could be stabilized
1612096	2019-09-02	86.9	10	900	Emergency	Bird strike on a 25 kv line shorted out power to pads P and AT causing a facility outage
1621695	2019-09-10	38.3	9	750	Emergency	During the tuning of P2B OTSG A and D excess produced gas was sent to flare
1626968	2019-09-15	45.4	5	750	Emergency	Pad P and AT tripped due to instrument air compressor problems
1633619	2019-09-22	32	7	700	Emergency	During eMVAPEX restart after a maintenance outage both compressors were lost during a process upset
1659696	2019-10-11	136	8	900	Emergency	low pressure BFW pump trip caused the Phase 2B steam plant to go down
1694432	2019-11-13	48.2	12	838	Emergency	eMVAPEX compressor B tripped causing gas to be directed back to the CPF flare
1706265	2019-11-20	51.3	88	600	Maintenance	Vapour Recovery Unit (VRU) outage to remove and replace compressors and pressure safety valves (PSV)
1746011	2019-12-24	80.9	10	312	Emergency	Phase 2 BFW pump tripped the OTSG and Heat Recovery Steam Generator (HRSG) resulted in produced gas flaring
1762940	2020-01-13	54.7	6	300	Emergency	Freezing caused the Phase 2 water plant to trip resulting in the shutdown of Phase 1 and Phase 2 OTSG's
1170692	2020-01-21	22	5	600	Emergency	Phase 2B flaring due to Phase 2B OTSG Boiler pass flow valve positioner failure and subsequent boiler outage
1171035	2020-01-21	25.5	4	600	Emergency	Flaring related to Phase 2B OTSG outage due to instability from bringing up new wells and balancing gas rates
1774543	2020-01-26	224	6	850	Emergency	During start-up following a trip of all Phase 2B OTSG's and GTG/HRSG the flare duration and volume were exceeded
1792300	2020-02-18	50.8	4	700	Emergency	VRU trip and gas pressure/flow disturbance caused the OTSG and HRSG duct burners to trip
30619819	2020-04-23	109.4	13	850	Emergency	Pad DD steam pipeline issues caused steam plant upset

Table 7. Reportable spills over the reporting period

AER ID	Date	Location	Fluid	Est. Volume (m^3)	Est. Duration (hrs)	Facility / Pipeline	Details	Corrective Action
20191444	2019-05-12	03-16-077-05W4	Fresh Water	1.0	N/A	Pipeline	Failed pressure test resulted from horizontal direction drilling into non-qualified line	A supervisor will be present at the exit side of the bore to witness the drill as it completes its run to provide visual assurance that the drill has not mistakenly passed through and into the opposite side of the bell hole
20191563	2019-05-23	15-12-077-05W4	Steam Condensate	0.2	1	Pipeline	Stretched bonnet valve studs and damage to the gasket, resulting in the hydrotest fluid leaking from bonnet	A Quality Hold Tag will prevent closing of drain valves until the pipeline is ready for commissioning and minimize potential for similar events
20192346	2019-08-02	02-16-077-05W4	Wash Water	6.0	0.17	Facility	Wash water spill within bermed pad boundary before the valve could be closed and capped	Drilling supervisor will have a vacuum truck hooked up to confirm tank is empty or perform visual confirmation before opening valves
20193436	2019-11-23	02-16-077-05W4	Boiler Feed Water	20	0.5	Facility	Boiler feed water pump developed a packing leak before operations was able to shutdown equipment	A new pump has been installed. Spill reporting communication requirements have been rolled out to all operators
20200304	2020-02-03	02-16-077-05W4	Utility Water	4.0	N/A	Facility	Steam building sump overflowed utility water and process fluids into containment and trench system	A sump high level alarm has been installed and a preventative maintenance program has been implemented to complete regular maintenance inspections of pump seals
20200312	2020-02-04	02-16-077-05W4	Produced Water	5.0	0.2	Facility	Phase 2 Induced gas flotation educator pump seal failed under normal conditions	A modified enclosure will allow operators to complete regular inspection for seal leaks
20200521	2020-02-25	02-16-077-05W4	Emulsion	9.1	N/A	Facility	The bonnet valve on exchanger released emulsion on the rack and surrounding area	Hard cladded insulation was installed around valve to ensure better distribution of heat from heat trace in colder months
20200832	2020-04-11	02-16-077-05W4	Emulsion	8.2	220	Facility	Spill to grade within tank farm secondary containment when tank levels passed a sample tap without with the spring-loaded valve engaged	After Action Review was conducted. The incident will be reviewed with operators including requirement to ensure all springs remain on spring loaded valves

Table 8. Voluntary self disclosures over the reporting period

Date	License/ Approval Type	Licensed Substance	License/ Approval/ ERP Ref.	Pipeline/ Installation	Line No. or Installation No.	Location	Non-compliance	Actions to Correct or Address the Non-compliance
2019-05-16	Well	Oil	478289	N/A	N/A	121/02-12-077-06 W4/0	Well testing requirement under Directive 17 Section 12.3.9 and MEG's approved MARP was not met	A Well Test Summary Report is generated and modified to track progress and identify wells that are not on track to meet requirements
2019-11-08	Well	Oil	Reference appendix	N/A	N/A	Reference appendix	Identified that the surface casing vent flow did not meet ID 2003-01 requirements	Internal process was adjusted to avoid exceeding 90-day window and has moved to an electronic form and tracking system
2020-01-20	Facility	Oil	37114	N/A	N/A	02-16-77-05W4M	Chloride concentrations >6000 ppm detected in P2 Water Treatment and Steam Processing plant in contravention of Directive 55	Determined primary sump liner is leaking. Third-party contractor retained to inspect and repair the liners on the sumps
2020-02-18	Well	Oil	106508	N/A	N/A	100/13-17-076-04W4/00	Casing failure was not reported to AER within 30 days per ID 2003-01	Abandonment of well will include removal of the existing casing patch to retrieve a WR plug and routine abandonment

Table 9. Contraventions over the reporting period

AER ID	Type	Date	Location	Details	Corrective Action
354491	Limit Exceedance	2019-06-08	02-16-077-05W4	During the restart of the Phase 2 Gas Turbine Generator, the EPEA NOx emission limit was exceeded	Third party support retained to tune the gas turbine and troubleshoot/repair the Inlet Bleed Heat Valve. EPEA approval has been amended to allow for period of time during startup when NOx limit can be exceeded
359149	Reporting Requirement	2019-09-20	10-12-077-05W4	The August 2019 gas analysis sample from the AP-V-410 group separator was accidentally destroyed	Different color identification tags for samples requiring analysis will be used Better communication controls are in place including an email alert system that indicates when a samples/analysis has been requested
362608	Limit Exceedance	2020-01-09	02-16-077-05W4	While running at steady state the Phase 2 Gas Turbine Generator EPEA NOx emission limit was exceeded	A turbine specialist recommended the Inlet bleed be left in manual to prevent freezing and temperature probe issues

Table 10. Corresponding compliance efforts over the reporting period

Compliance Category	Details
Flaring	• Goal is to work to keeping flaring under reporting limits if safe to do so • Boilers brought up as quickly as possible when trips occur to minimize gas to flare • Reliability and process safety management assigned to investigate as required • Flare / Vent procedure and log update and communicated
Spills	• Ongoing spill mitigation and communication protocols in place • All spills are immediately cleaned up • Weekly incident investigation meeting to assign investigator, identify root cause and implement corrective actions and mitigations • Reportable spills to ground include third party soil analysis completed with release reports
Voluntary Self Disclosure	• When required corrective actions or mitigations and identified and implemented • 2019 specific corrective actions identified in VSD table
Contraventions	• When required corrective actions or mitigations and identified and implemented • 2019 specific corrective actions identified in Contravention table

4.12 Future Plans

Over the next reporting period, the previously approved boiler blowdown evaporator and drum boiler projects are expected to be complete. Final commissioning and start-up dependent on market conditions. No other significant plant modifications are anticipated; however, MEG is continuously assessing optimization options aimed at enhancing overall performance.

Figure 14 presents the future planned development areas. In the coming year, MEG expects to submit amendment applications for subsurface modification under Directive 23.

FIGURES

Figure 1 **Annotated scheme-level lifespan production plot**

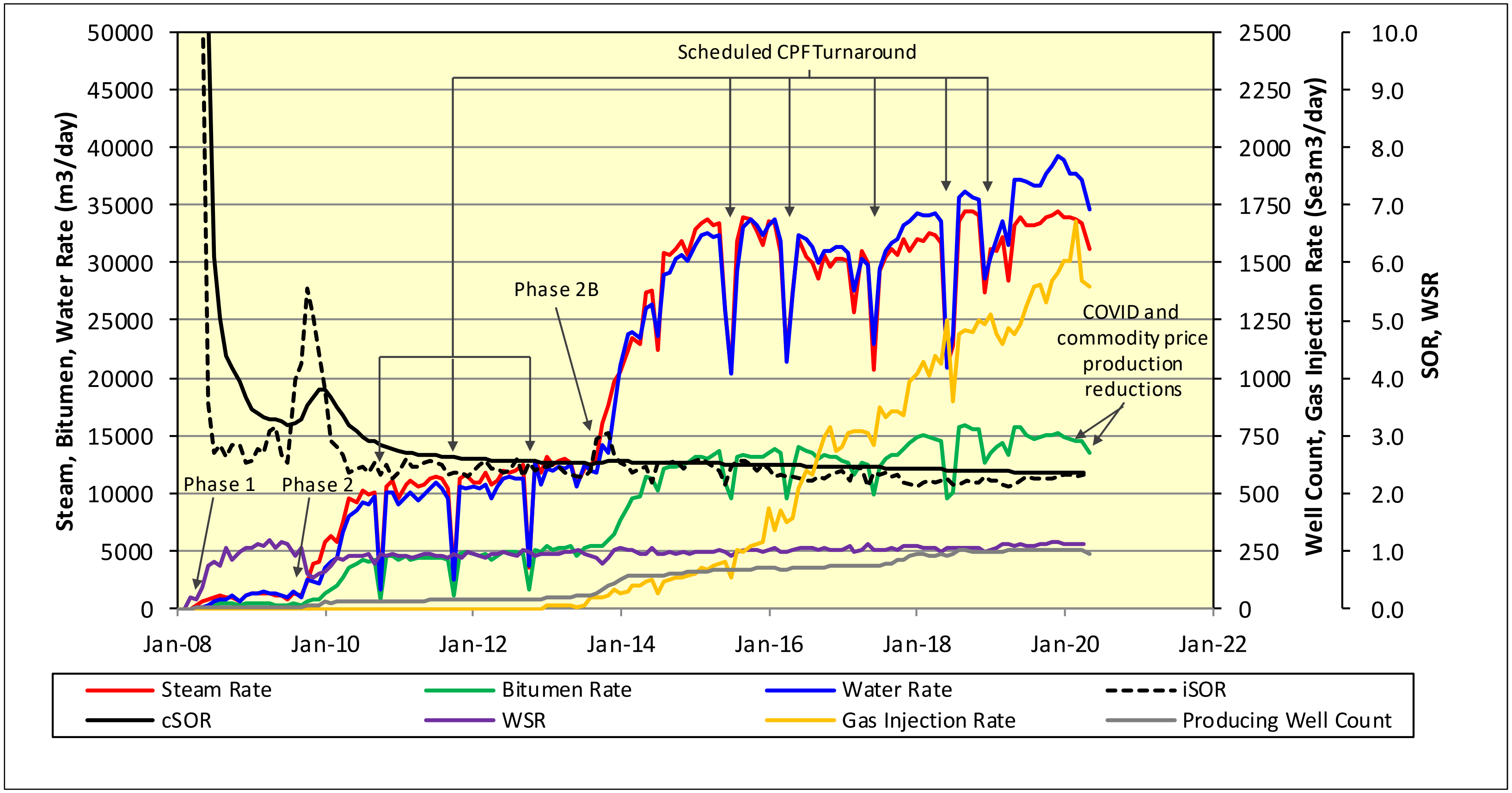
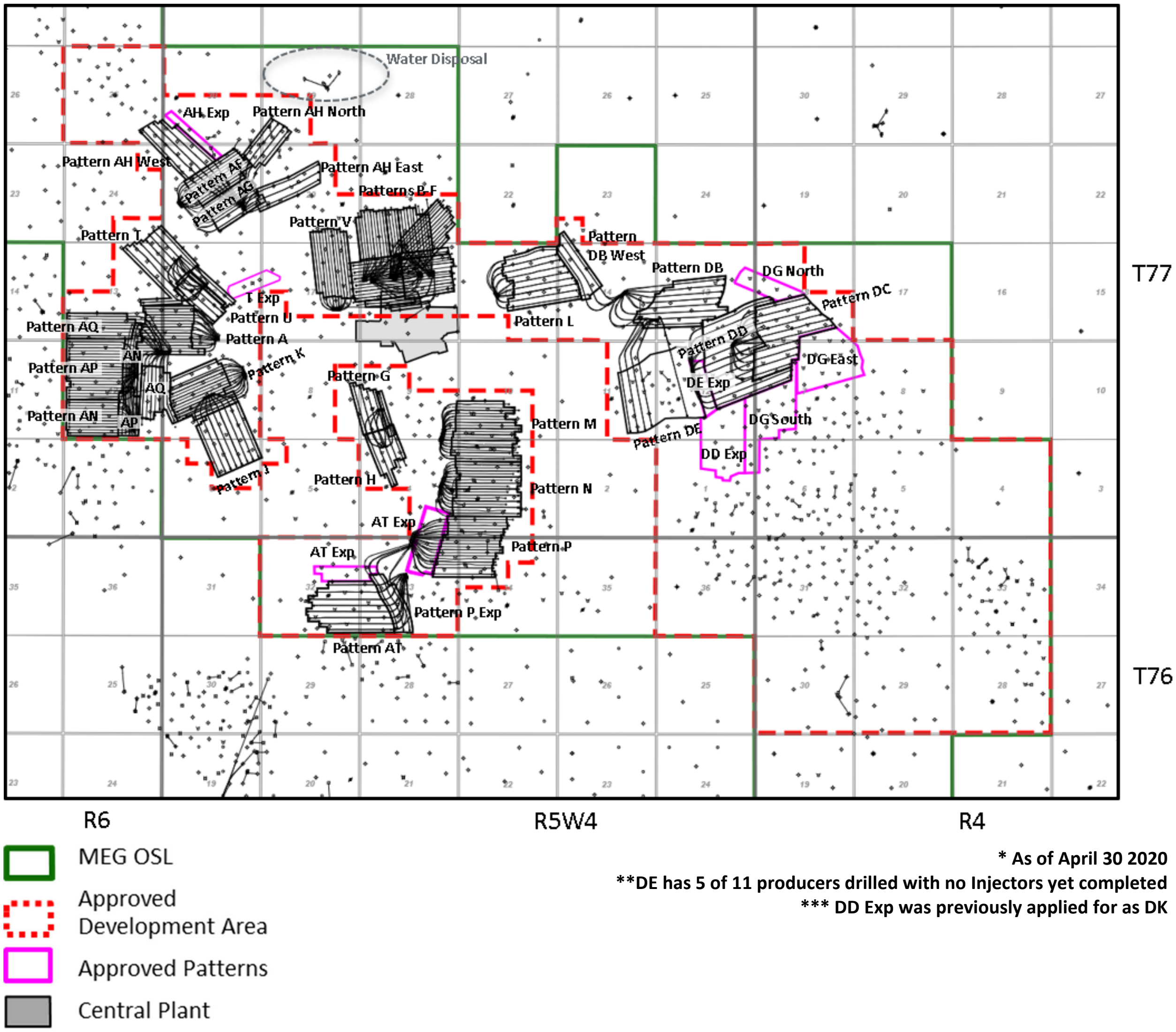
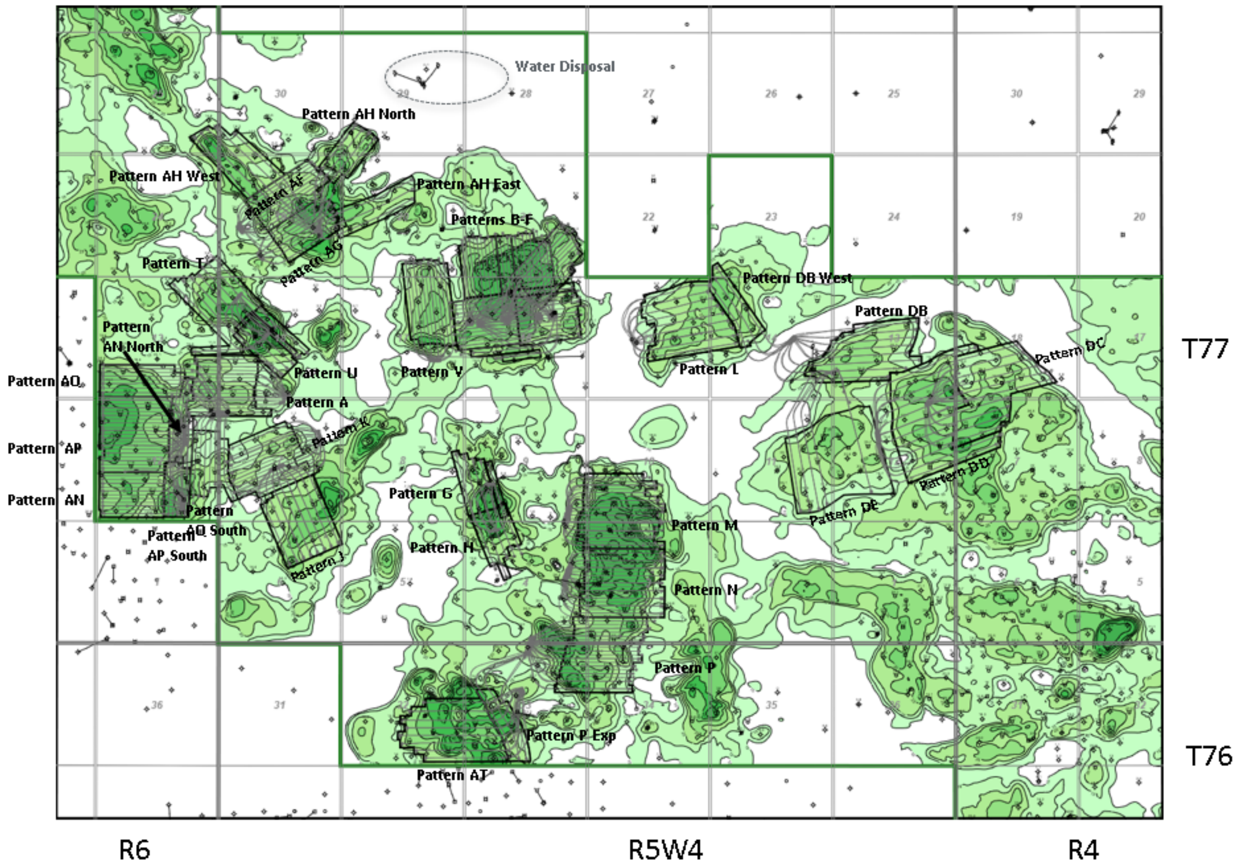


Figure 2 Drilled and approved drainage pattern areas



*** As of April 30 2020**
****DE has 5 of 11 producers drilled with no Injectors yet completed**
***** DD Exp was previously applied for as DK**

Figure 3 Net pay isopach



SAGD Pay Cutoffs:

- Continuous bitumen pay ≥ 10 m (defined by logs and core)
- So ≥ 50% (~6 wt% bulk mass oil)
- Porosity (density) ≥ 25%

Min contour = 10 m
Contour interval = 5 m

CLRP
Project Area

SAGD
Patterns

Figure 4 **Associated gas in communication with pay**

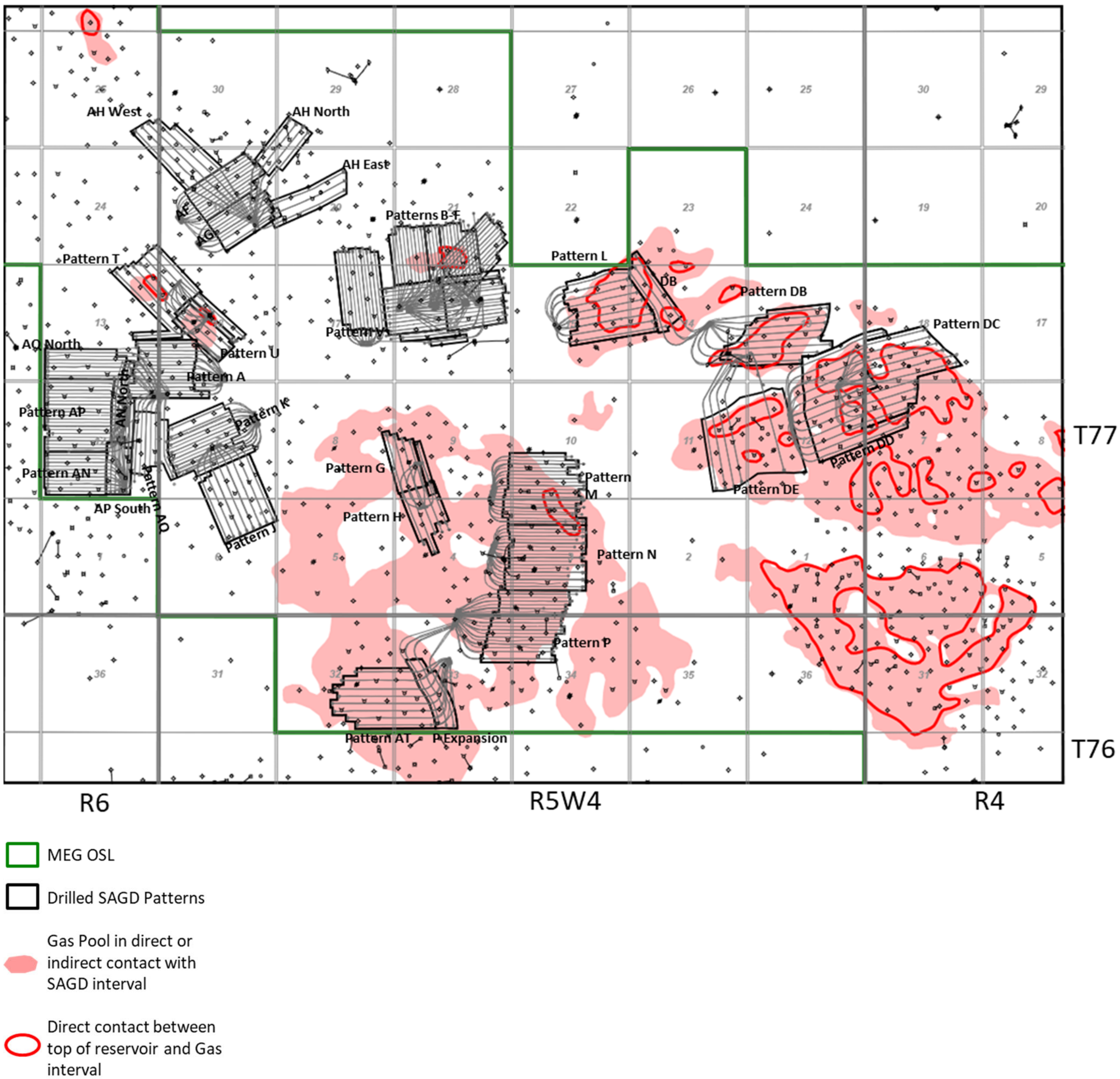


Figure 5 Net basal water isopach in communication with pay

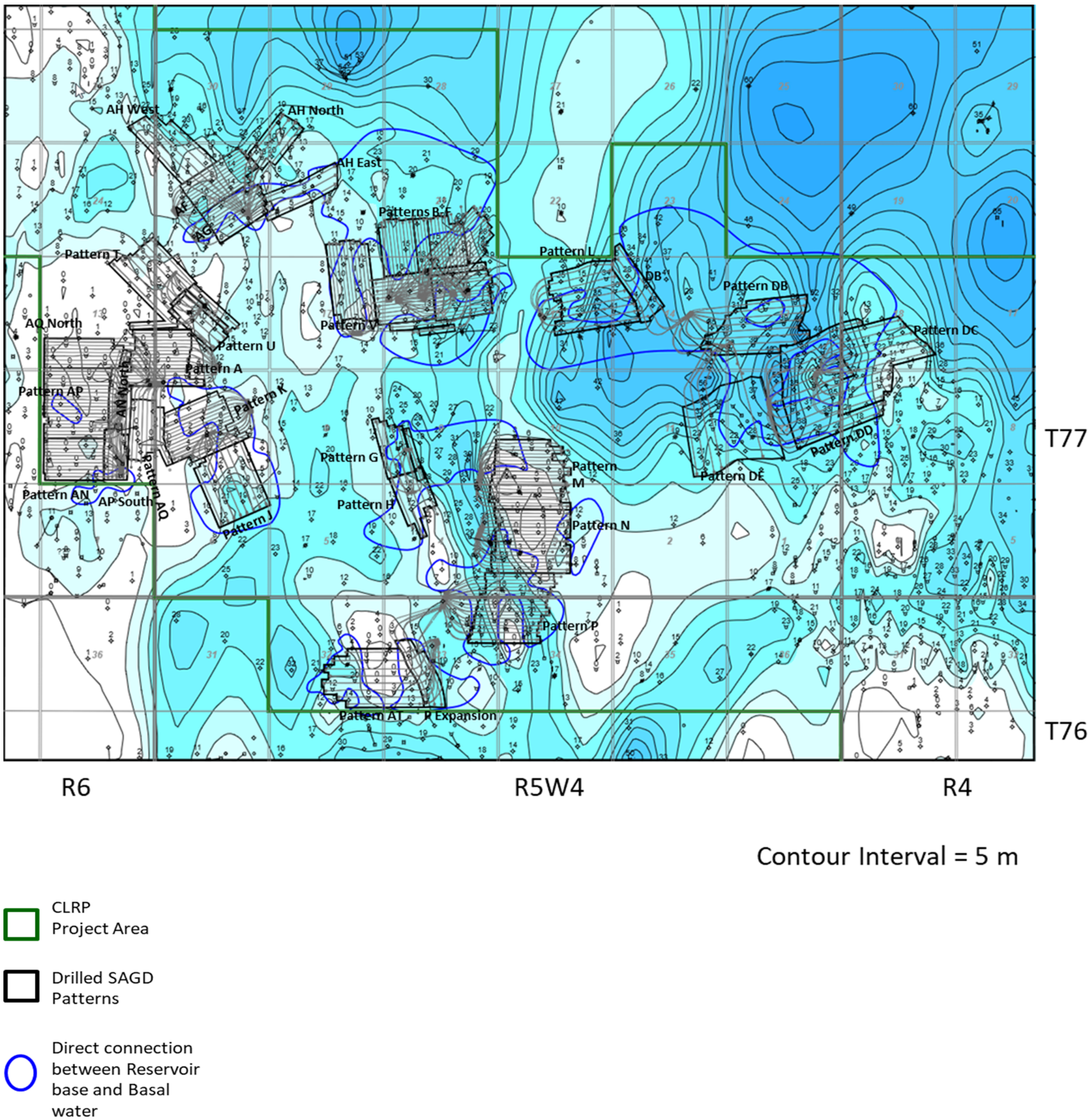


Figure 6 **Seismic acquisition in the project area**

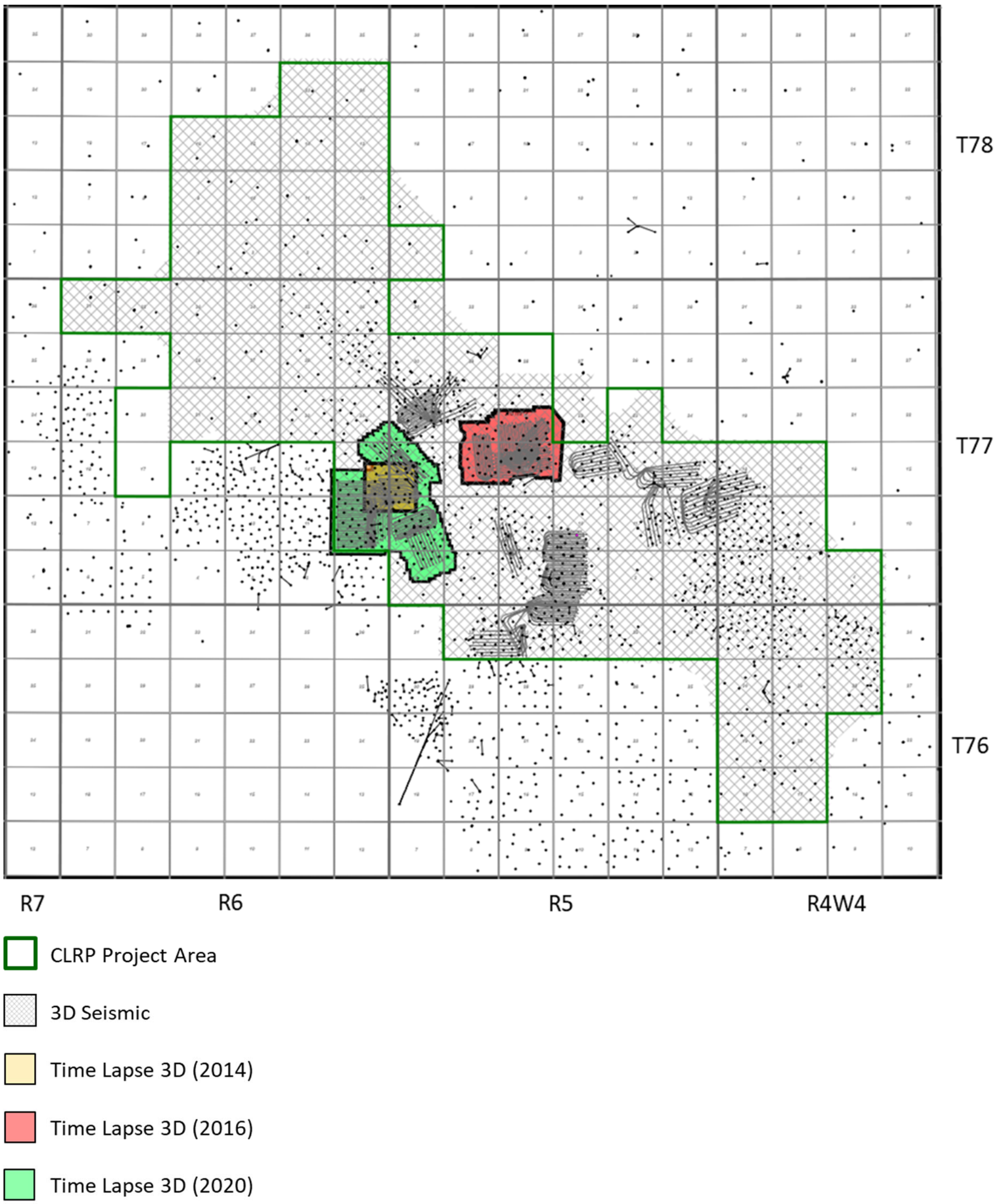
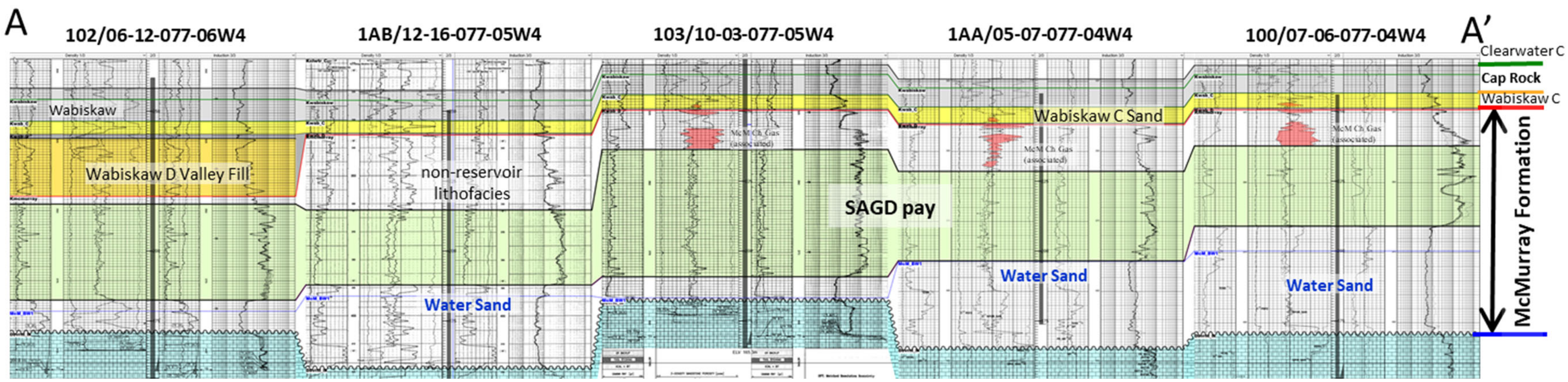


Figure 7 Representative cross section within the active development area



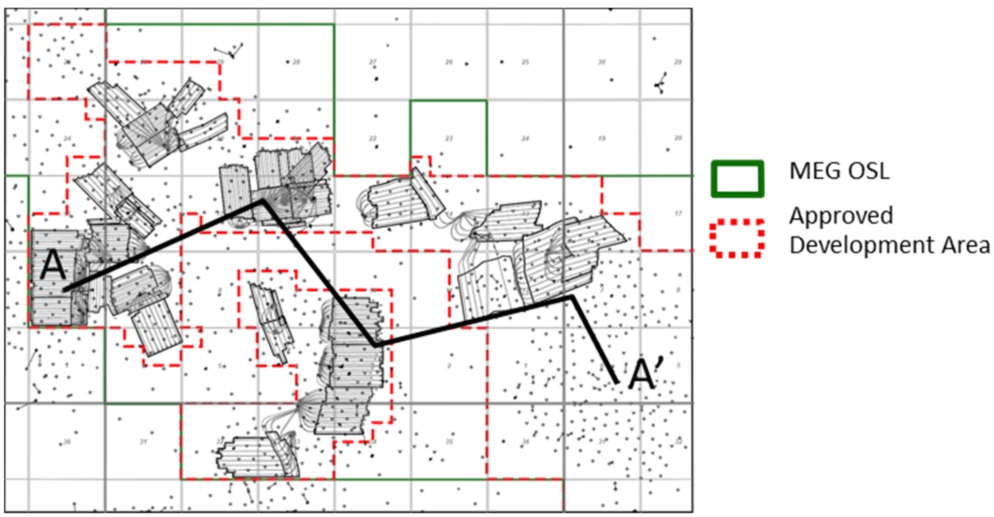


Figure 8 Injection wells by type

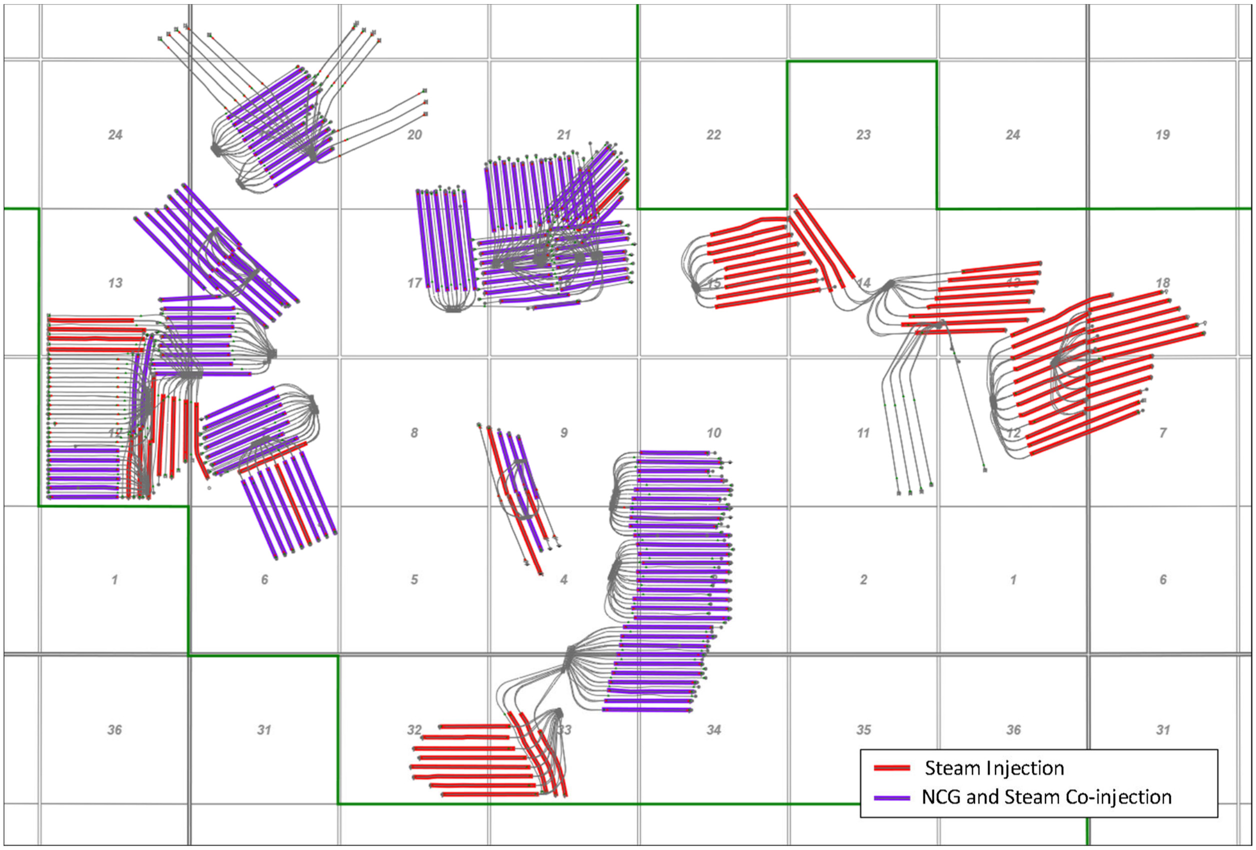


Figure 9 **iSOR, NCG injection concentration, and cSOR performance for MEG's Phase 1, Phase 2, and Phase 2B well patterns**

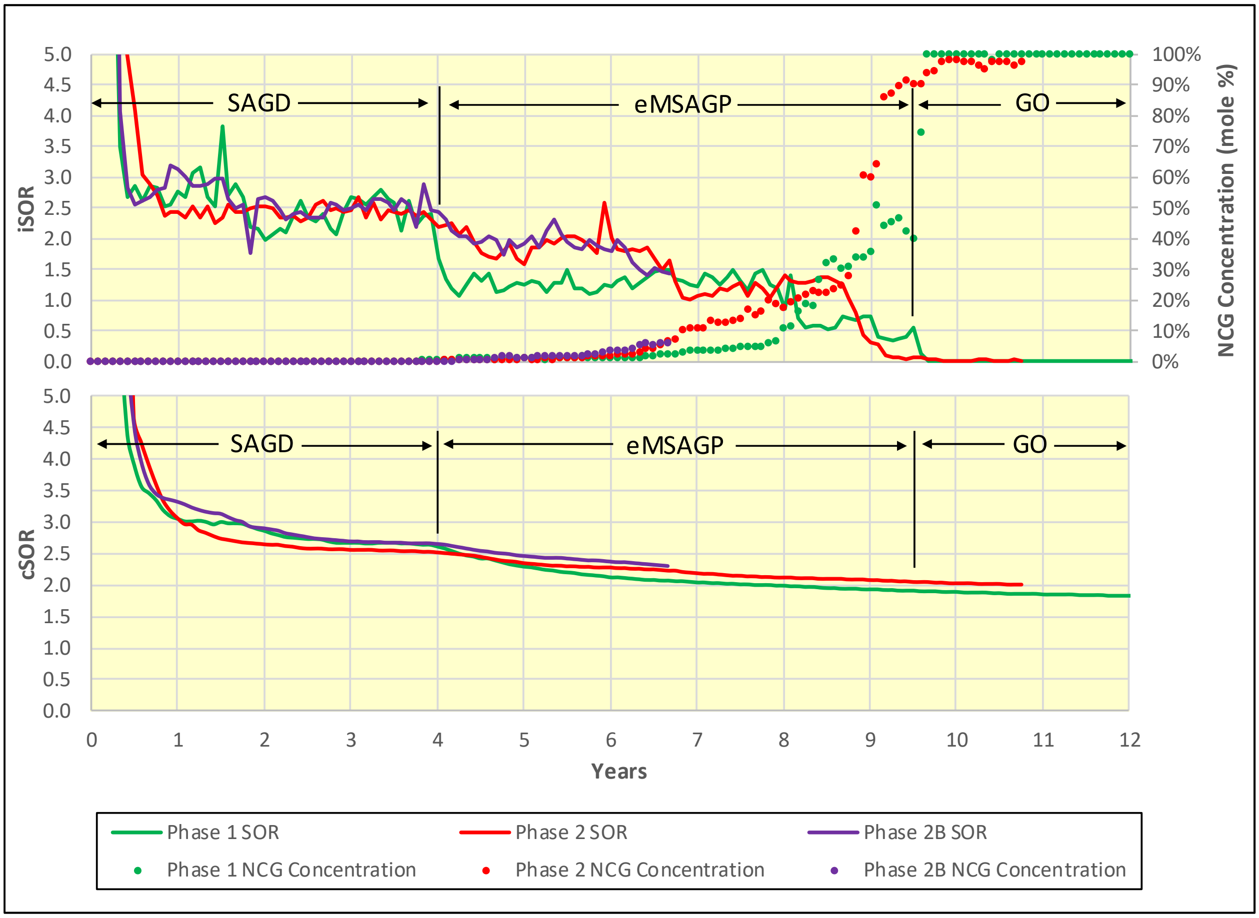


Figure 10 Constructed and planned surface infrastructure within the development area

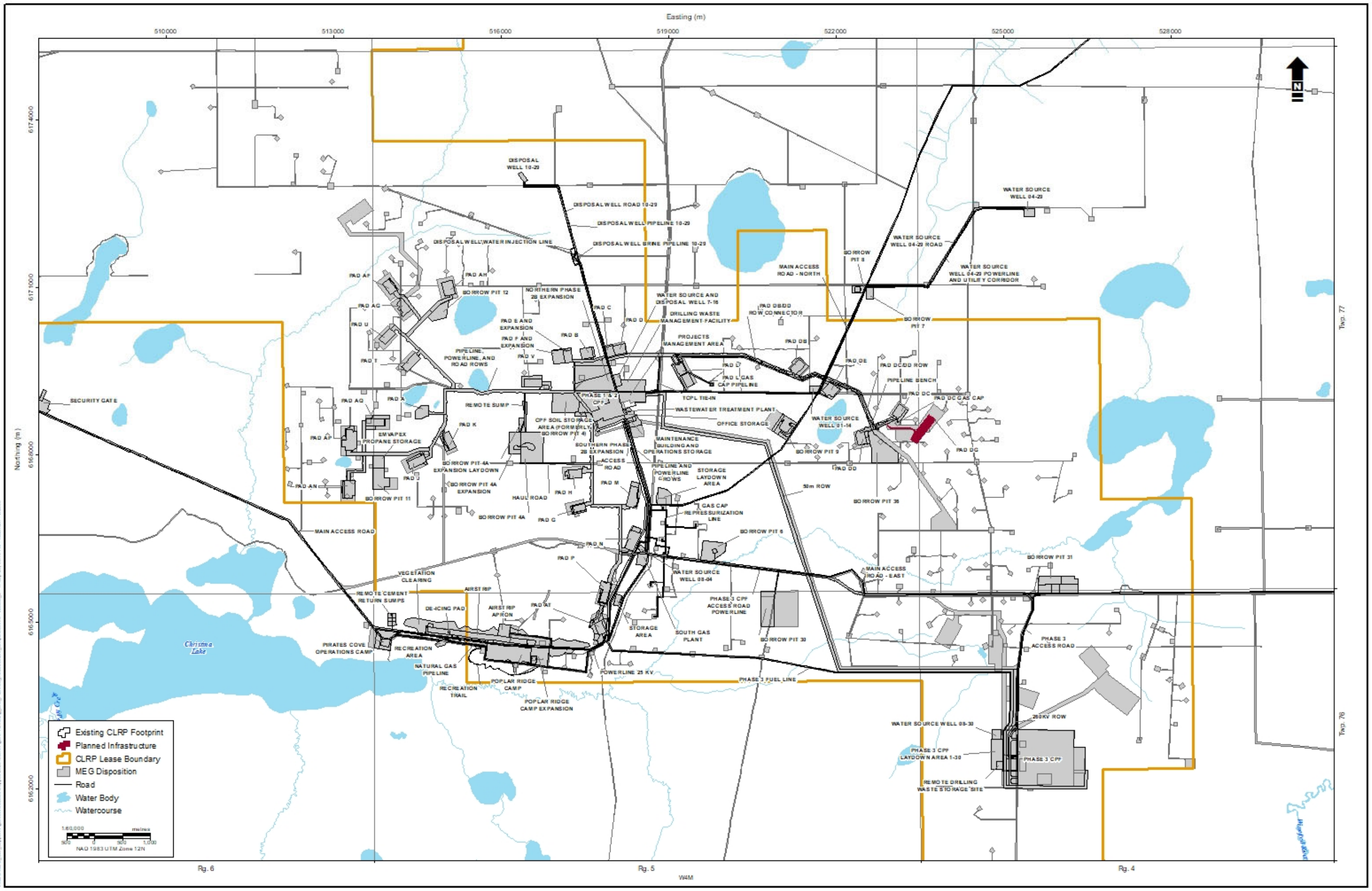


Figure 11 **Source and disposal wells within the development area**

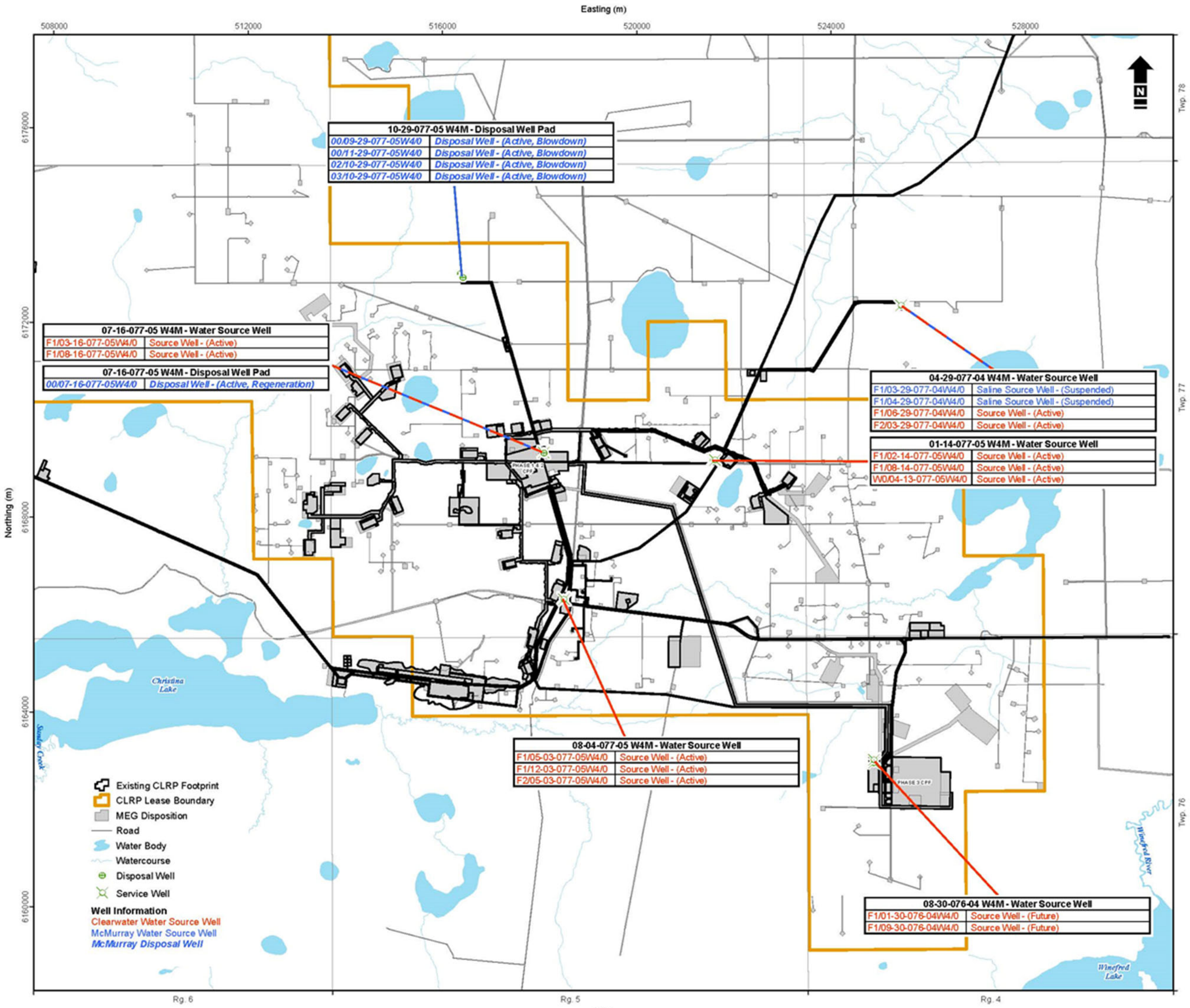


Figure 12 **Facility Performance: Bitumen Treatment**

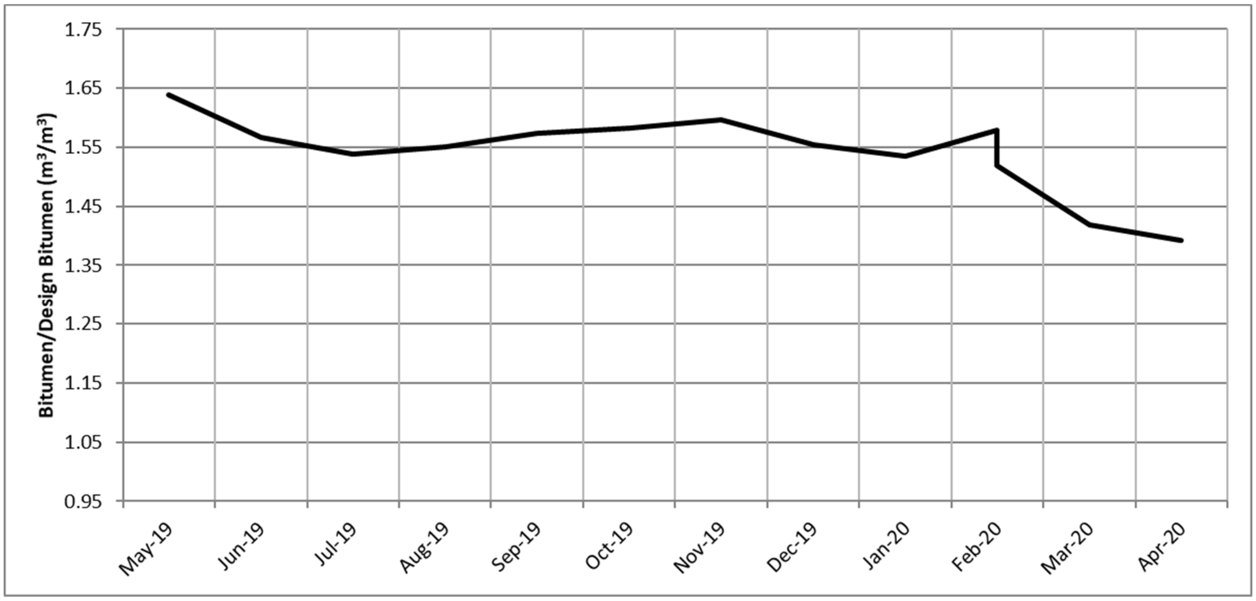


Figure 13 Facility Performance: Steam Generation

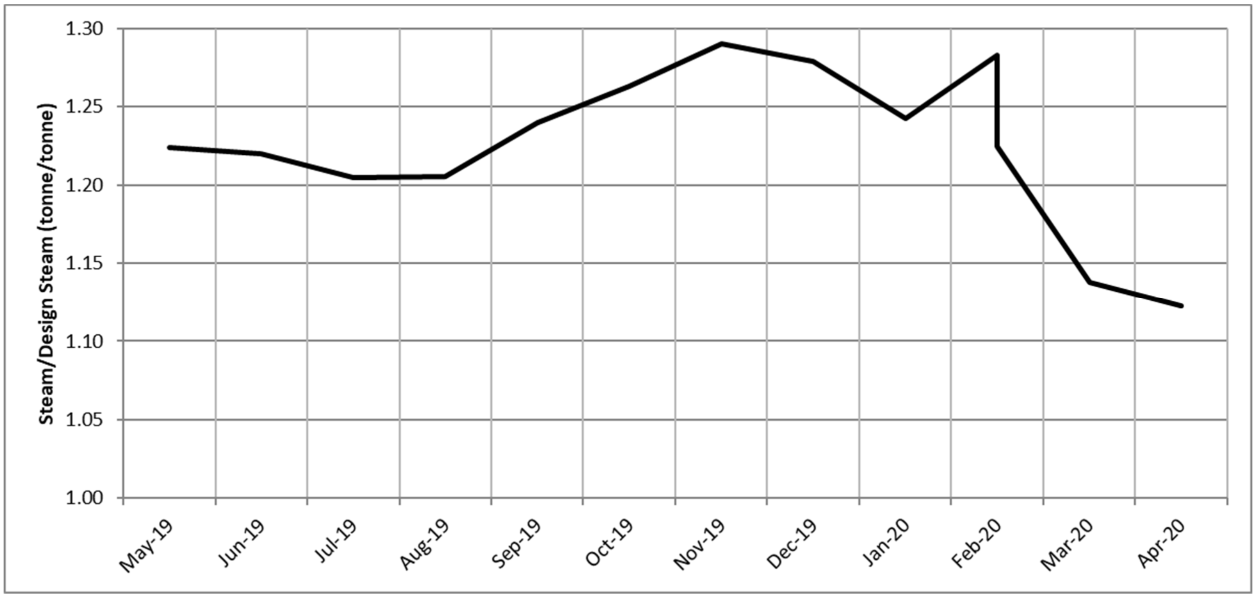
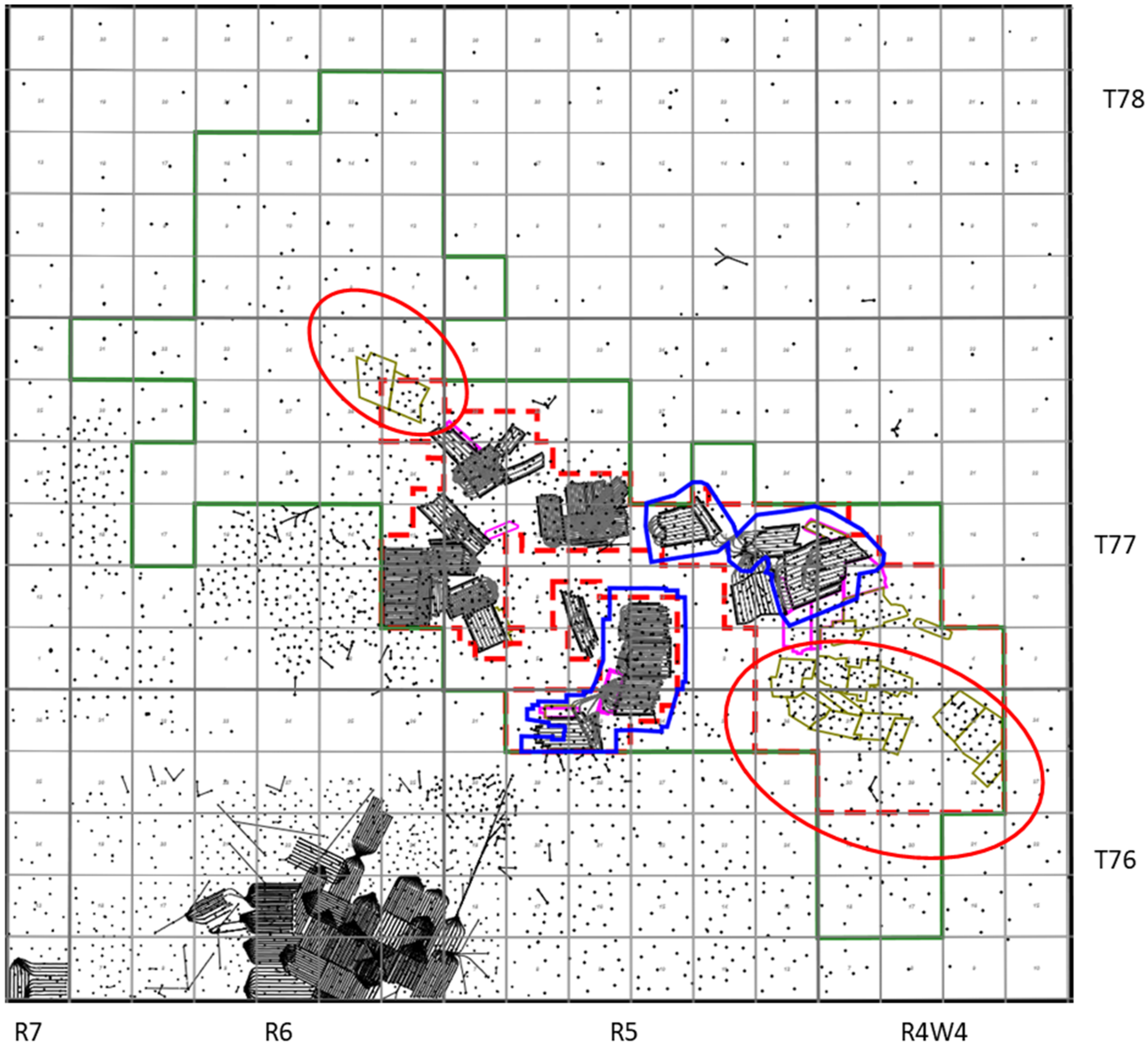


Figure 14 Future planned development areas



CLRP Project Area
Approved Development Area
Active Patterns
Approved SAGD Patterns
Planned Pattern Additions
Central Plant
Future Core hole focus areas
Potential Future 4D Seismic