Christina Lake Regional Project
2020/2021 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 2020, average daily bitumen production was 82,441 bbl/day with a steam-oil-ratio (SOR) of 2.32. Bitumen production in 2020 was materially impacted by a combination of voluntary price-related production curtailments in response to the decrease in commodity prices and a major planned turnaround at the Phase 1 and 2 facilities in Q3 of 2020. In the first quarter of 2021, average daily bitumen production was 90,842 bbl/day with an SOR of 2.37.

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	4,199,072,000	264,201,224	6%
Development Area	2,273,623,000		12%
Combined Active Well Pattern Area	780,477,000		34%

*Minimum Reservoir thickness of 10m
** As of April 30, 2021
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)	24.0
Pay Porosity range (fraction)	0.30-0.36
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	22.7	32.3%	75.8%	3,898,000	3,673,000	56%	58%	60%	61%
Phase 2*	2,690,534	24.1	32.7%	78.4%	16,613,000	14,342,000	63%	65%	73%	75%
V	650,137	25.9	31.6%	73.7%	3,926,000	3,479,000	33%	~50%	37%	50-60%
G**	215,631	17.6	31.4%	73.0%	876,000	843,000	40%	50-60%	41%	50-60%
H**	66,813	19.1	32.6%	71.5%	298,000	228,000	46%	50-60%	61%	60-70%
J	781,677	21.1	32.7%	74.1%	3,999,000	3,653,000	22%	~50%	24%	50-60%
K**	672,726	21.2	32.6%	74.0%	3,447,000	3,224,000	41%	50-60%	44%	50-60%
M	978,051	29.6	31.8%	79.0%	7,152,000	6,686,000	52%	60-70%	56%	60-70%
N	970,951	24.3	32.7%	79.8%	6,152,000	5,687,000	43%	50-60%	47%	60-70%
T	756,229	21.0	31.4%	81.5%	4,071,000	3,236,000	29%	50-60%	37%	60-70%
U	454,179	25.2	30.8%	80.3%	2,834,000	2,649,000	38%	50-60%	40%	60-70%
AP South	246,047	25.0	33.0%	78.3%	1,590,000	1,485,000	41%	60-70%	44%	60-70%
AF	498,601	19.9	32.4%	81.4%	2,609,000	2,110,000	40%	50-60%	50%	60-70%
AG	414,226	21.5	32.7%	76.7%	2,235,000	2,095,000	34%	50-60%	37%	50-60%
AN	776,936	26.3	32.6%	80.1%	5,339,000	4,804,000	50%	60-70%	56%	60-70%
P	1,269,292	20.2	31.6%	74.3%	6,030,000	4,955,000	31%	50-60%	38%	60-70%
AQ	856,937	20.1	33.1%	79.5%	4,532,000	4,184,000	29%	60-70%	31%	70-80%
AT	962,439	29.3	31.0%	77.0%	6,723,000	6,093,000	21%	60-70%	23%	70-80%
L	946,741	23.4	33.0%	72.5%	5,286,000	4,571,000	19%	50-60%	21%	60-70%
DB	1,211,412	21.8	33.1%	68.0%	5,950,000	4,867,000	13%	50-60%	16%	60-70%
DC	1,035,394	24.4	32.0%	72.4%	5,860,000	5,022,000	8%	60-70%	10%	70-80%
DD	1,367,931	25.7	32.6%	70.3%	8,066,000	6,394,000	7%	50-60%	9%	60-70%
AH	1,206,401	21.1	32.2%	79.4%	6,543,000	5,043,000	0%	50-60%	0%	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. 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 and 3 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 of wells that have been suspended over the reporting period. At CLRP there are currently no well patterns that have been abandoned.

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

Pattern	Well	UWI	Well License Number	License Status
A	A3P	03/01-13-077-06W4/0	0351525	Suspended
	A4P	04/01-13-077-06W4/0	0351526	Suspended
	A6P	02/08-13-077-06W4/0	0351528	Suspended
AN	AN2N	07/02-13-077-06W4/0	0483097	Suspended
E+F1	F1P	06/16-16-077-05W4/0	0374858	Suspended
F	F6N	WO/05-21-077-05W4/0	0453088	Suspended
D6+D7	V7N	05/07-16-077-05W4/0	0460579	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
1929454	Amendment application for subsurface modifications to pattern AH	09-Sep-2020
1929953	Amendment application for subsurface modifications to pattern AT	29-Oct-2020
1932420	Amendment application for subsurface modifications to pattern DG	24-Mar-2021
1932205	Amendment application for the addition of clauses associated with the CLRP Sulphur Management Plan	31-Mar-2021

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:

- Commissioning of MVC Evaporator and Drum Boilers.

- Commissioning of brine disposal pipeline for process wastewater stream segregation.
- Commissioning of a 2nd produced gas recycle compressor.
- Modified blanket gas distribution in Phase 2B sales oil tanks resulting in a reduction in diluent flashing and pressure excursions in these tanks.
- Catalytic viscosity reduction pilot project commenced.
- Optimization of air scouring equipment and procedures to prolong the operating life of water treatment vessel media.
- Upgraded H_2S analyzers to improve reliability.
- On-going thermal imaging of steam generation equipment to provide information on condition of tubes.

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

- Continued improvement in the implementation of Advanced Process Control trial for Phase 2B (free water knockout) FWKO and Treater interface control.
- Initiated study to develop a virtual BTU analyzer for combustion tuning.
- Improved automated process controls on boilers to mitigate process upsets.
- Initiated automated HP steam pipeline pressure control through field injection to mitigate upsets.

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

- Investigating options for data analytics and Advanced Process Control.
- Modifying sampling conditioning in physical BTU analyzer to improve reliability.
- Continued optimization of the chemical treatment program.
- Trialing different disposal filter configurations to reduce operating costs and labour associated with maintaining disposal system.
- Designing and implementing a produced gas filtration system to improve fuel gas mixed drum performance and reliability.
- Post-commissioning optimization of new steam generators and water treatment equipment.

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, 2020 to April 30, 2021, MEG Energy has no unaddressed non-compliant events. During that period, the AER completed 18 inspections of the CLRP with only one inspection found to be unsatisfactory. All required corrective actions have been implemented.

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.

Table 6. Reportable flaring and venting events over the reporting period

AER ID	Date	Est. Volume (e3m3)	Est. Duration (hrs)	H_2S Conc (ppm)	Reason	Details
30658686	2020-06-04	36.8	122	600	Maintenance	Flaring related to ramp down for the Phase 1 and 2 extended Turnaround
30664160	2020-06-09	69.9	504	425	Maintenance	Flaring associated with Phase 1 LP flare due to Turnaround activities
30699619	2020-07-01	56.8	744	425	Maintenance	Flaring associated with Phase 1 LP flare due to Turnaround activities
30728709	2020-08-26	55.9	12	585	Emergency	Power trip in the sub-station. Brought units down. Produced gas sent to flare
30728103	2020-08-22	24.1	528	425	Maintenance	Flaring associated with Phase 1 LP flare due to turnaround activities
30758782	2020-09-26	37.7	5	600	Emergency	Phase 1&2 main gas XV switch failed resulting in Phase 1 & 2 OTSG's and P2 GTG tripping. With boilers down gas had to be sent to flare.
30790725	2020-10-10	137.1	5	600	Emergency	Duct burners tripped on temperature during WECC testing
30797737	2020-10-19	47.4	9	700	Emergency	O2 analyzer failed causing Phase 2B OTSG-A to trip. Gas had to be sent to flare until the boiler was returned to service.
30998086	2020-12-09	4.0	5	3	Maintenance	Produced gas compressor outage. Small volume of purge gas sent to flare
31071860	2021-01-16	30	42	0	Maintenance	Residual propane from storage bullet was sent to the AP Pad flare stack
31074459	2021-01-22	34	5	575	Emergency	eMVAPEX recovery package tripped due to false emulsion transmitter. Access gas directed back to the CPF 2B flare stack.
31086655	2021-02-03	20	4	550	Emergency	eMVAPEX recovery package tripped due to gas pressure swing from switching wells in test. Access gas directed back to the CPF 2B flare stack.
31090429	2021-02-06	29.0	5	569	Emergency	eMVAPEX recovery package tripped. Access gas directed back to the CPF 2B flare stack.
31090595	2021-02-08	24	5	565	Emergency	eMVAPEX solvent header pressure started to swing from the wells causing 2 compressors to trip. Access gas directed back to the CPF 2B flare stack.
31095558	2021-02-08	8	6	450	Emergency	Phase 2 VRU tripped due to low lube oil flow to first stage. initially caused flaring that was reported to AER (#31091837) and venting from the Phase 1 and 2 tank farm.
31091837	2021-02-09	7	6	50	Emergency	Phase 2 VRU tripped causing flaring to the Phase 1 HP flare stack. VRU successfully repaired ending the flaring event.
31099016	2021-02-18	57	17	557	Emergency	Boiler feedwater pump tripped causing the Phase 1 & 2 steam generators and Phase 2 GTG to go down
31184357	2021-03-06	6	6	300	Emergency	eMVAPEX compressors tripped due to 2B-PV-52101 passing. Access gas directed to CPF.
31189253	2021-03-31	34	4	500	Emergency	eMVAPEX compressors tripped twice during the night. Access gas directed to CPF.
31189278	2021-03-31	193	7	350	Emergency	Phase 2B Steam generators and GTG all tripped on inlet separator level. Access gas directed to the flare.
31186447	2021-04-07	1	6	1500	Maintenance	Planned flaring event for eMVAPEX outage. System was purged with N2

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
20201549	2020-07-05	02-16-077-05W4	Produced Water/Utility Water	2.5	N/A	Facility	Fluid released from a vacuum truck due to using two hoses at the same time resulting in one hose losing suction and releasing fluids on to the ground.	Designed modified partial doors that would allow access into tanks while providing external seal Develop Spill Prevention Incident Alert to only use one vacuum truck hose at a time to minimize risk of suction loss.
20201898	2020-08-17	02-16-077-05W4	Blowdown	90	Unknown	Facility	Hole on the bottom of the 24” blowdown line caused fluid to escape from the line to the ditch and the Phase 2 Stormwater pond.	Leak occurred on a dead leg section of the pipe due to location of valve. Dead leg was removed and integrity inspections completed.
20202716	2020-11-20	02-16-077-05W4	Boiler Feed Water	8	0.5	Facility	Boiler feed water pump developed a packing leak. Sump was not able to keep up and water spilled into the trench.	Maintenance and repairs completed on the high pressure boiler feed pumps. Spill prevention and reporting communication requirements were rolled out.
20202770	2020-11-27	13-03-077-05W4	Boiler Feed Water	0.87	N/A	Facility	Water truck developed a hole in the tank and leaked out boiler feedwater on the road.	Truck taken out of service and inspected. All other trucks in the fleet inspected. Tank wall thickness inspections implemented as part of the contractor’s future maintenance program.
20210051	2021-01-06	02-16-077-05W4	Lime Sludge	10	1.2	Facility	Lime sludge hose coupling failed on the top of the 2B HLS causing the hose to fail. Lime sludge was released to the ground below.	Replaced HLS hoses to include stainless steel fittings. PM updated for regular change out and job plans updated to formalize inspections.
20210078	2021-01-07	15-12-077-05W4	Emulsion	0.02	N/A	Pipeline	Drain valve leaking emulsion to the frozen ground below (off lease).	Continue with winterization and freeze reporting program, and pipeline inspection program. Review completed to remove emulsion bypass pipelines.

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
2021-02-19	Well	Oil	443357	N/A	N/A	100/08-32-074-16 W4/0	Failed to seek AER approval during abandonment operations on Feb 14, 2021, which resulted in the execution of a non-routine abandonment.	MEG has ensured that abandonment programs are clearly written that any deviation from the program requires MEG approval and that the AER will be notified immediately should operational issues occur that would prevent the abandonment from being executed in accordance with Directive 020.

Table 9. Contraventions over the reporting period

AER ID	Type	Date	Location	Details	Corrective Action
368308	Uptime Requirement Not Met	2020-05-25	02-16-077-05W4	Monthly 90% CEMS availability limit exceeded due to accumulated downtime hours resulting from data integrity issues on the Phase 2B Cogen GM32 NOx analyzer.	Analyzer vendor brought to site to investigate and determine root cause of the NOx data changes after the daily check cycle.
368054	Limit Exceedance	2020-06-18	02-16-077-05W4	Monthly 90% CEMS availability limit exceeded due to accumulated downtime hours resulting from an extended outage on the Phase 2B Cogen GM32 NOx analyzer.	Work completed included replacing CPU, filter cleaning, gaskets replaced, replacement of the carbon sachet desiccant, the main beam splitter, the 4Q divider, lamp, and swivel arm.
369881	Limit Exceedance	2020-07-31	02-16-077-05W4	Monthly 90% CEMS availability limit exceeded due to accumulated downtime hours resulting from an extended outage on the Phase 2B Cogen GM32 NOx analyzer.	Phase 2B Cogen GM32 NOx analyzer sent to Germany for repair. Spare analyzer configured and installed. Spectrometer was changed out and unit re-commissioned November 8, 2020. No issues since repair complete.
369882	Limit Exceedance	2020-08-05	02-16-077-05W4	Monthly 90% CEMS availability limit exceeded due to accumulated downtime hours resulting from an extended outage on the Phase 2B Cogen GM32 NOx analyzer.	Phase 2B Cogen GM32 NOx analyzer sent to Germany for repair. Spare analyzer configured and installed. Spectrometer was changed out and unit re-commissioned November 8, 2020. No issues since repair.
369778	Late Report	2020-07-31	02-16-077-05W4	Due to waiting on approval for data backfill from AER for missing CEMS data hours, MEG was not able to submit CEMS data by the month end deadline.	Remained in communication with the AER answering follow up data requests in a timely fashion to expedite the approval of the Method 4 backfill. Method 4 was approved and required monthly reports submitted
505054	Non-Compliance with Manual #5.6.100.1 – Pipeline license P22055 Line #33 (AER inspection finding)	2020-09-23	16-09-077-05-W4	During an AER inspection, it was identified in both 2018 & 2019 Cathodic Protection Surveys that segment 33 required a mag anode be installed @ 8-4-77-5-W4 location. This was a non-compliance with CSA Z662 [9.9.2].	Corrective Action letter submitted to AER on October 22, 2020. Cause identified and repaired (blown fuse and wiring). System has been re-energized in accordance with code NACE SP0169.

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 updated and communicated
Spills	• Ongoing spill mitigation and communication protocols in place. Focused spill campaigns in place for 2021 based on spill data trends to target highest risk/occurrence spills. • 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 • 2020-2021 specific corrective actions identified in VSD table
Contraventions	• When required, corrective actions or mitigations are identified and implemented • 2020-2021 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 optimized andfully operational. An expansion to the sulphur removal plant is expected to be commissioned by January 2023 with construction expected to commence as early as Q1 2022. 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**

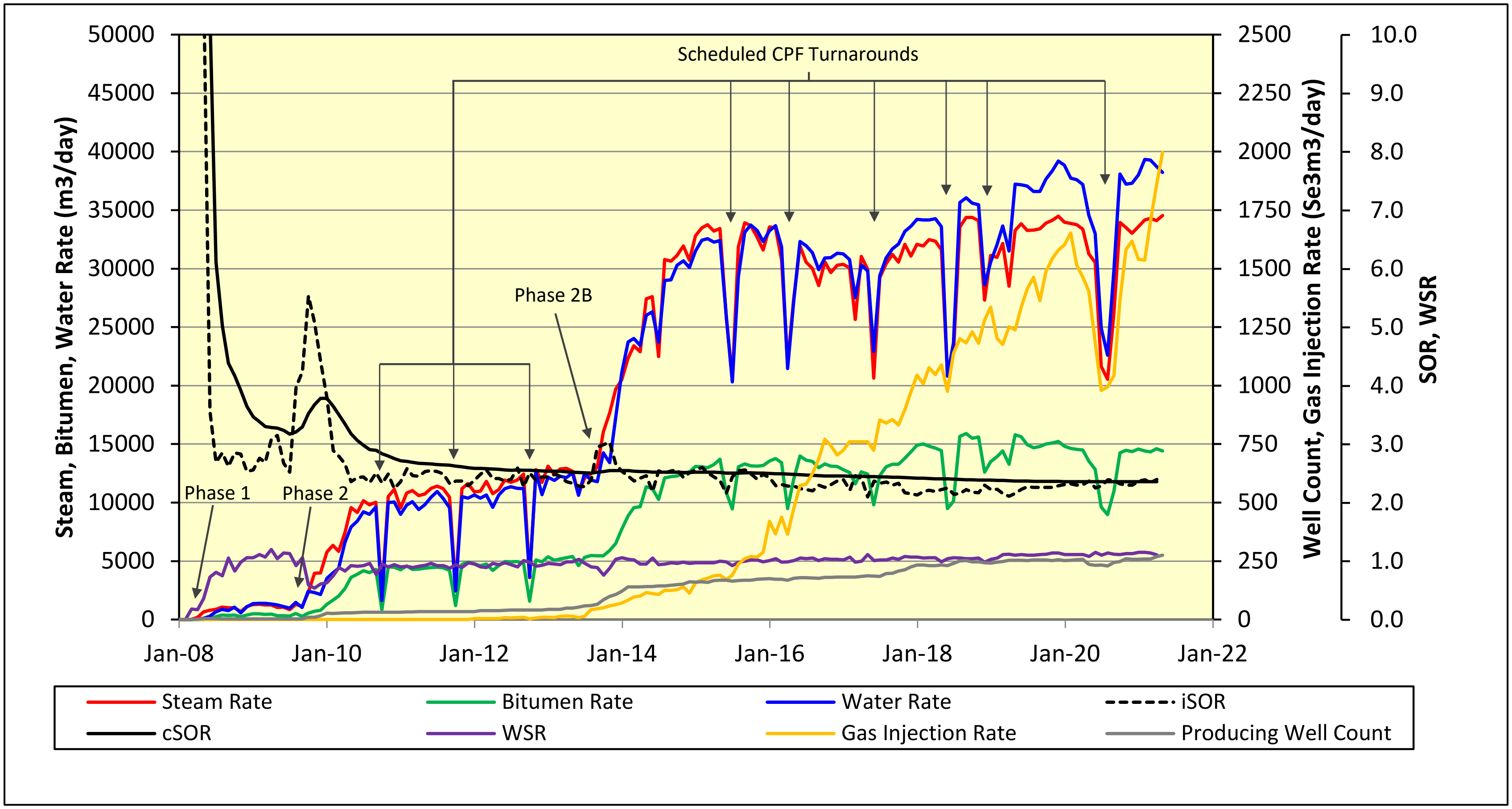


Figure 2 **Drilled and approved drainage pattern areas**

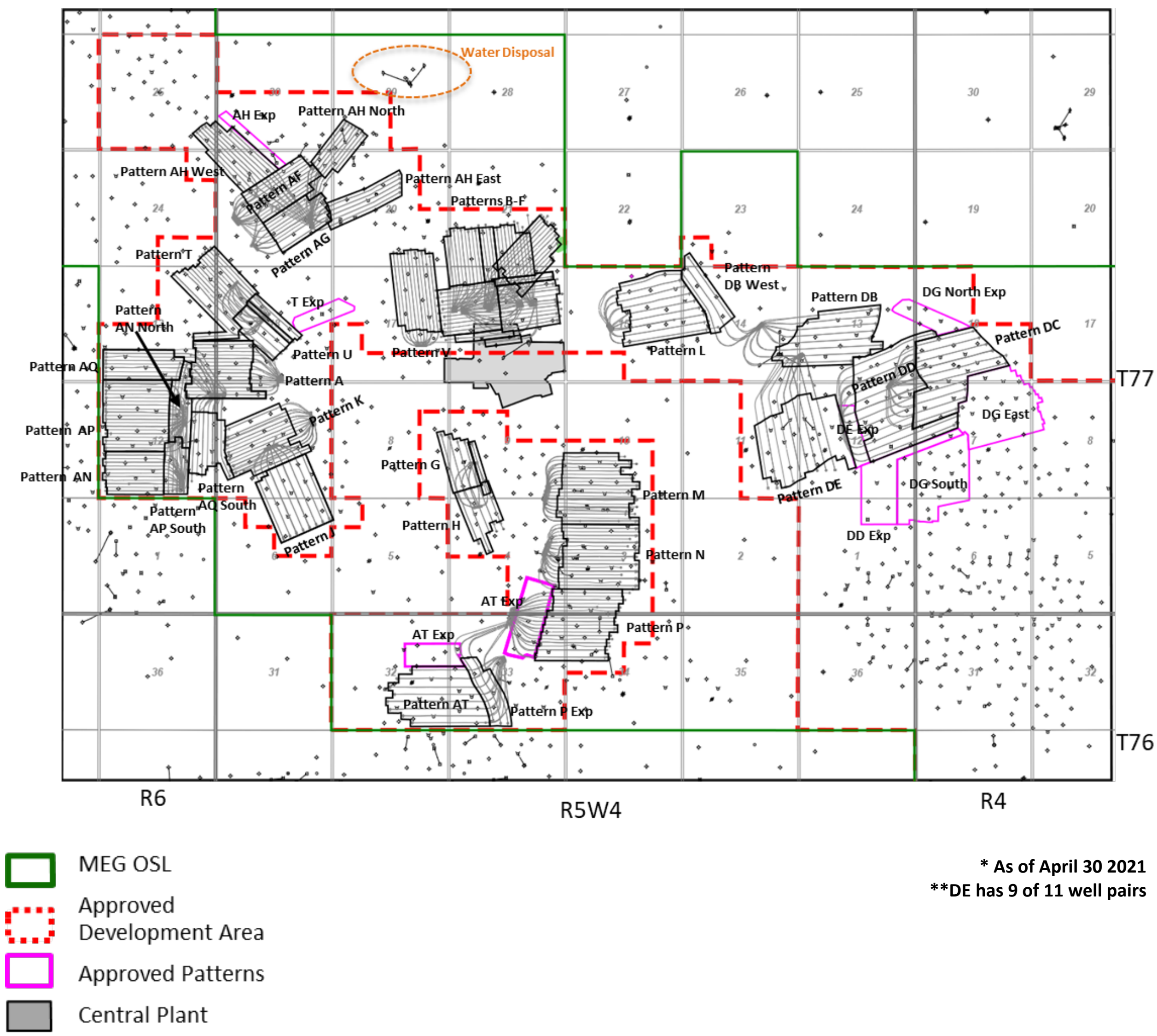
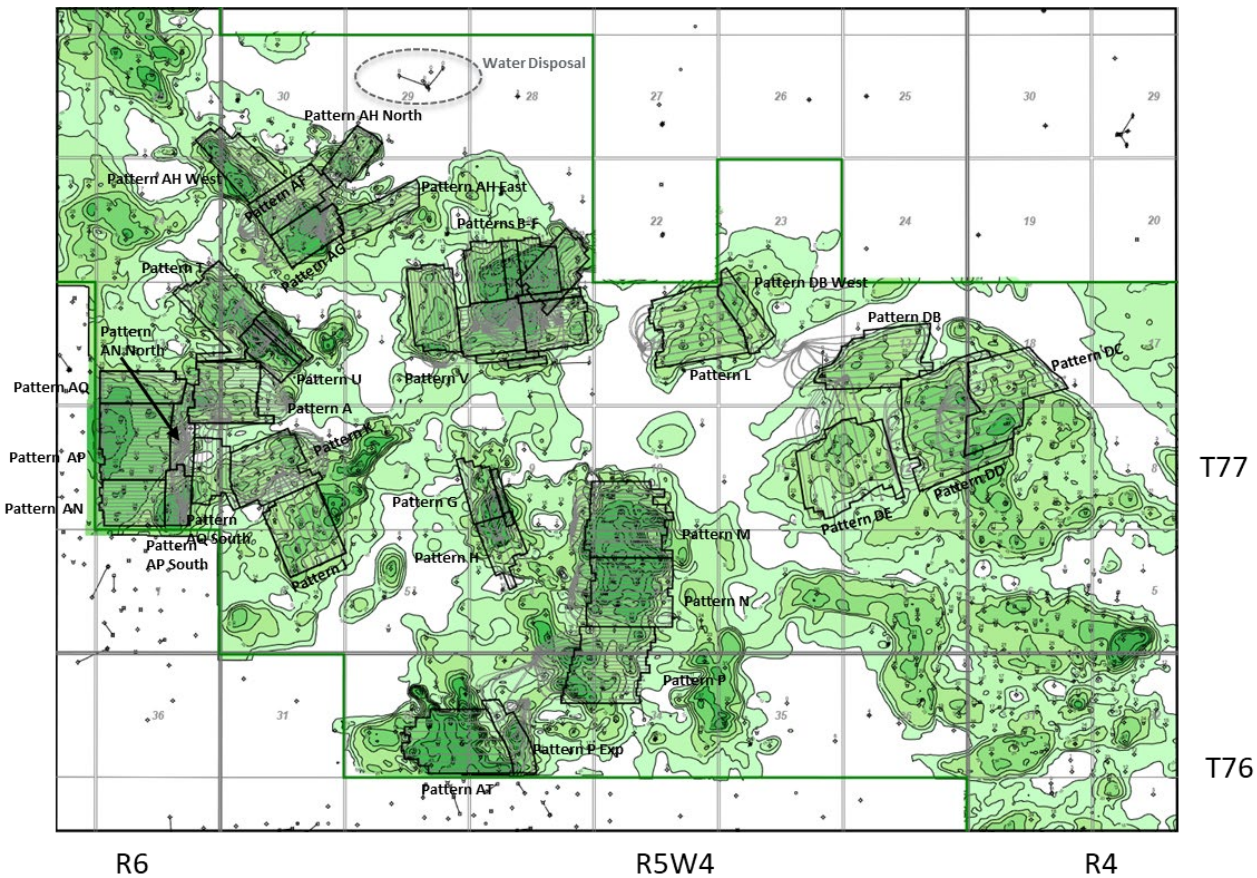


Figure 3 Net pay isopach



SAGD Pay Cutoffs:

- Continuous bitumen pay ≥ 10 m (defined by logs, images 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**

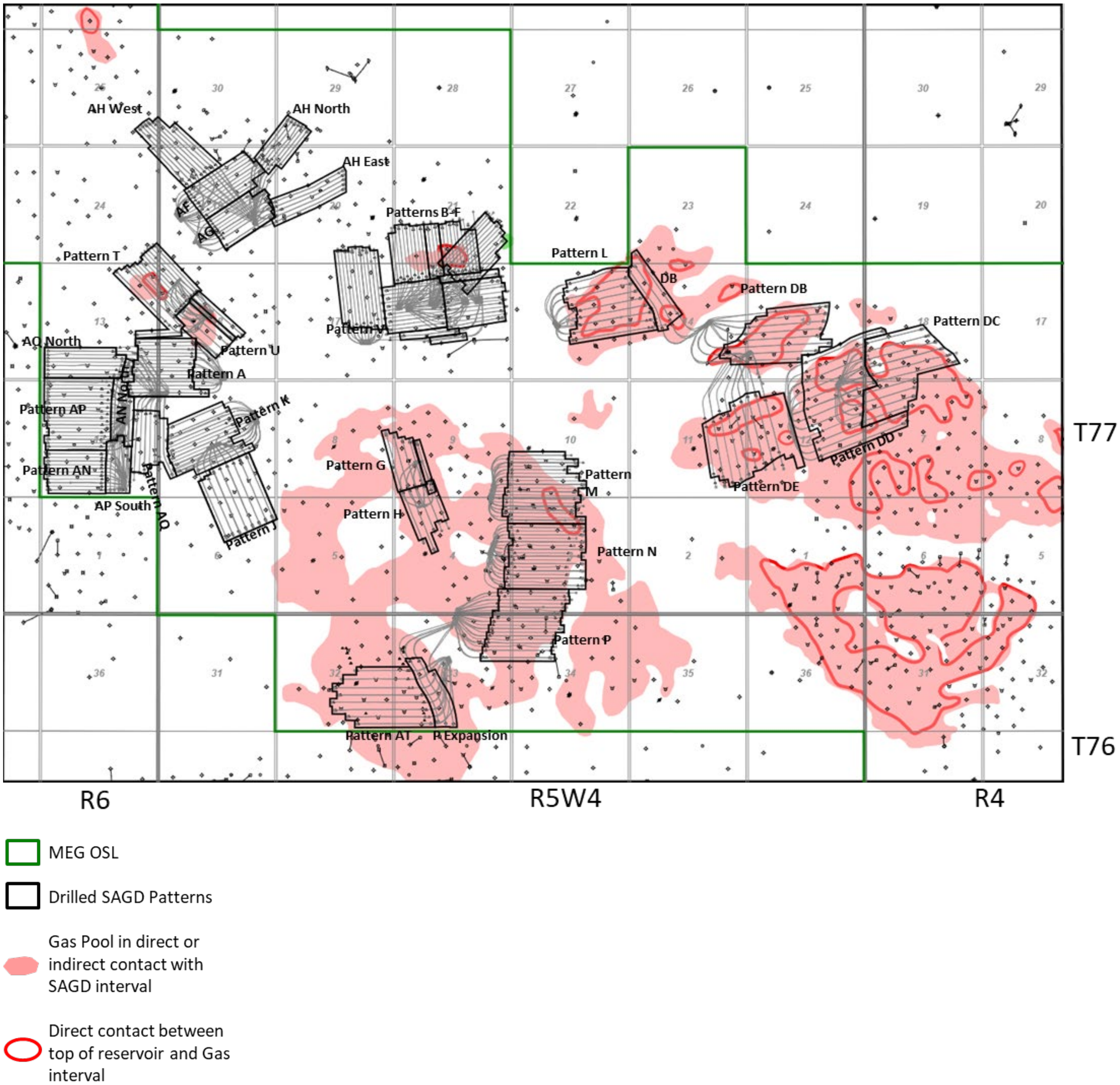
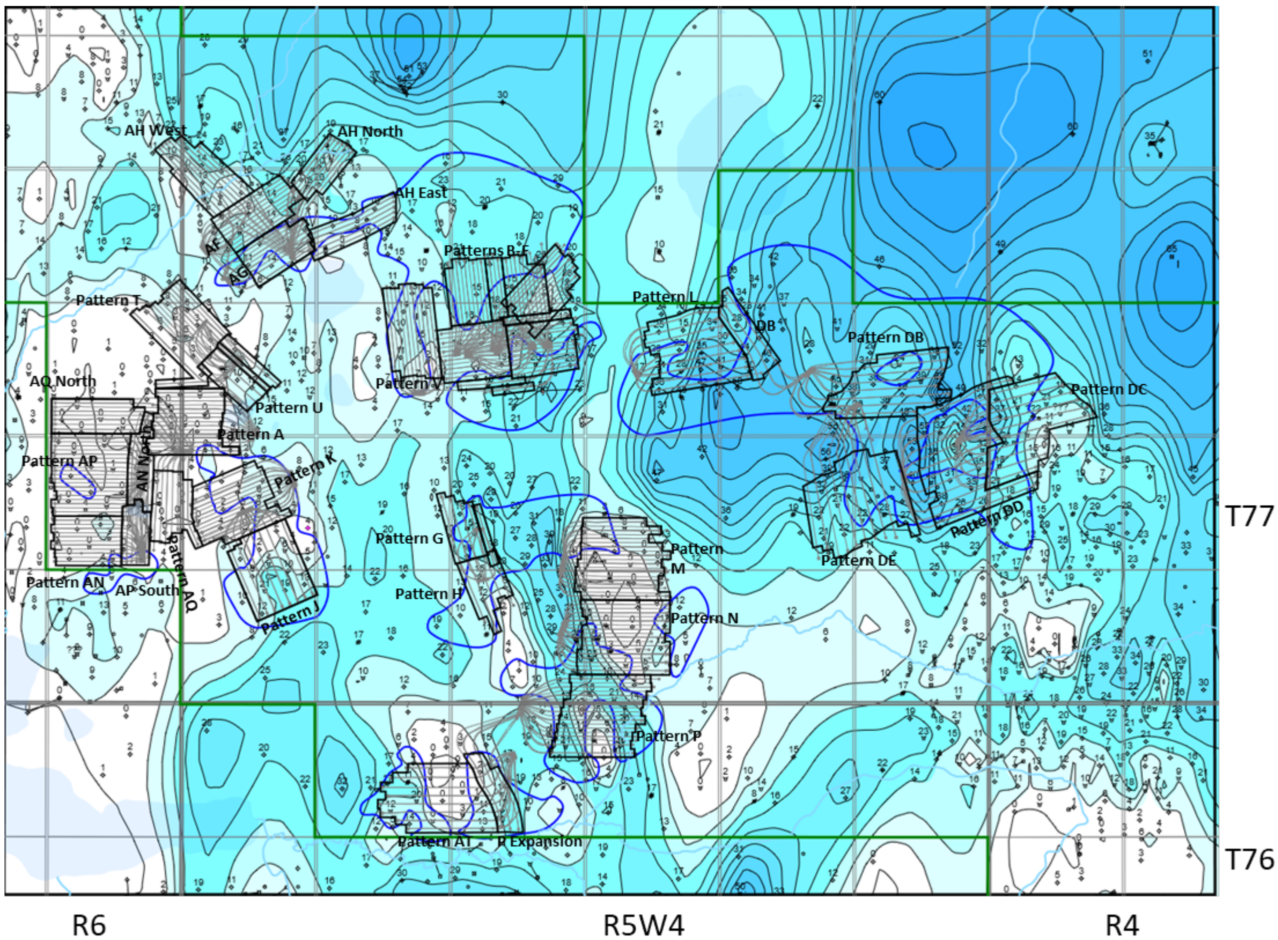


Figure 5 **Net basal water isopach in communication with pay**



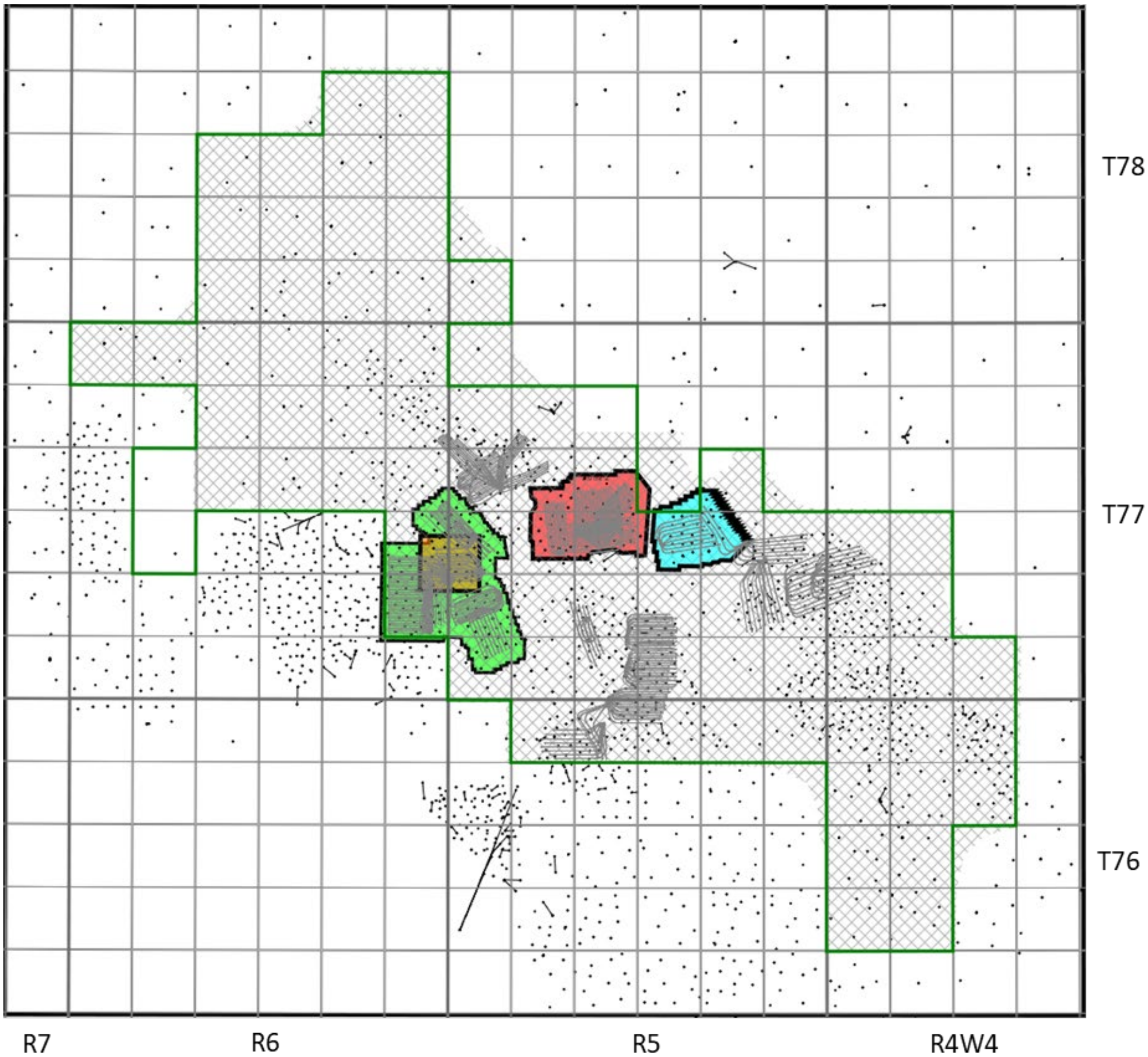
Contour Interval = 5 m

CLRP
Project Area

Drilled SAGD
Patterns

Direct connection
between Reservoir
base and Basal
water

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



CLRP Project Area

3D Seismic

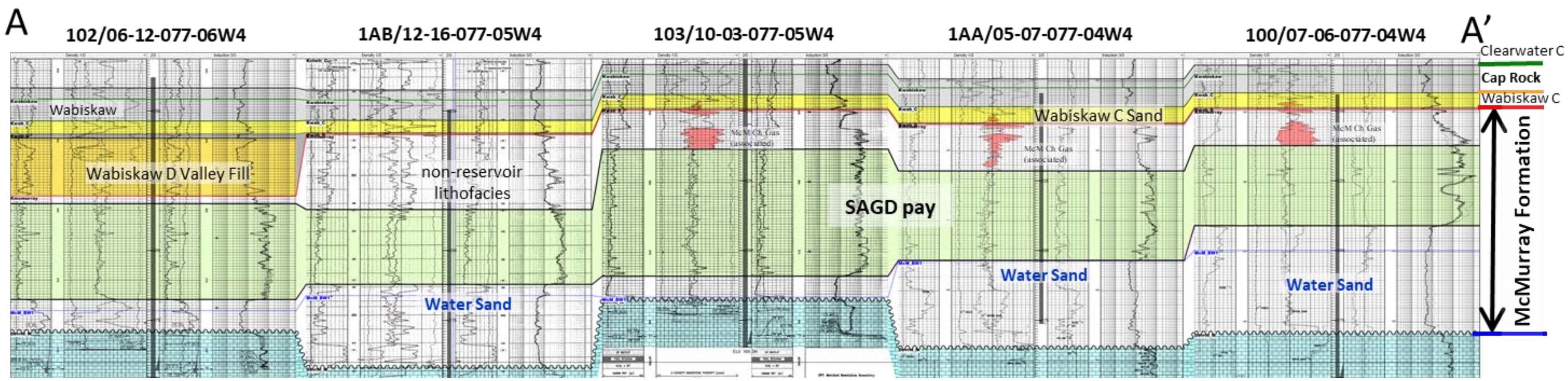
Time Lapse 3D (2014)

Time Lapse 3D (2016)

Time Lapse 3D (2020)

Time Lapse 3D (2021)

Figure 7 Representative cross section within the active development area



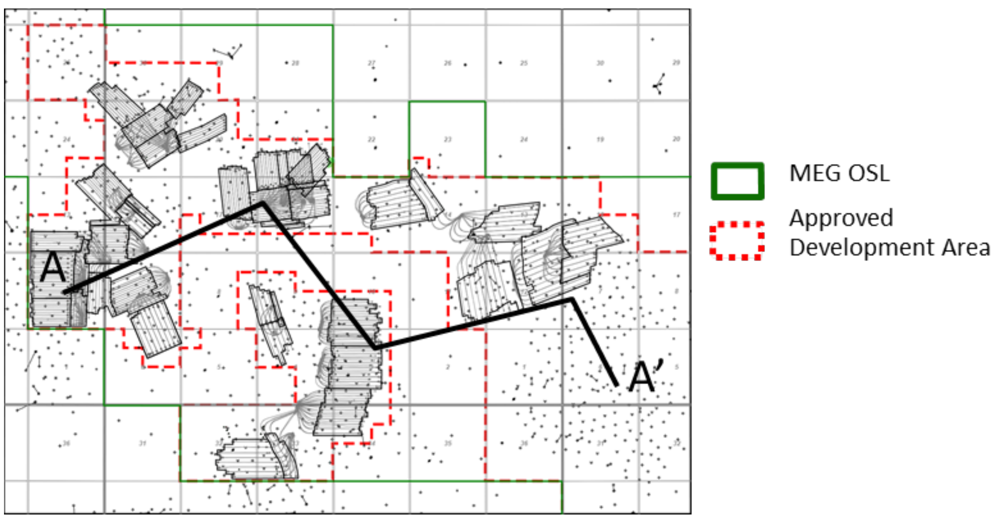


Figure 8 **Injection wells by type**

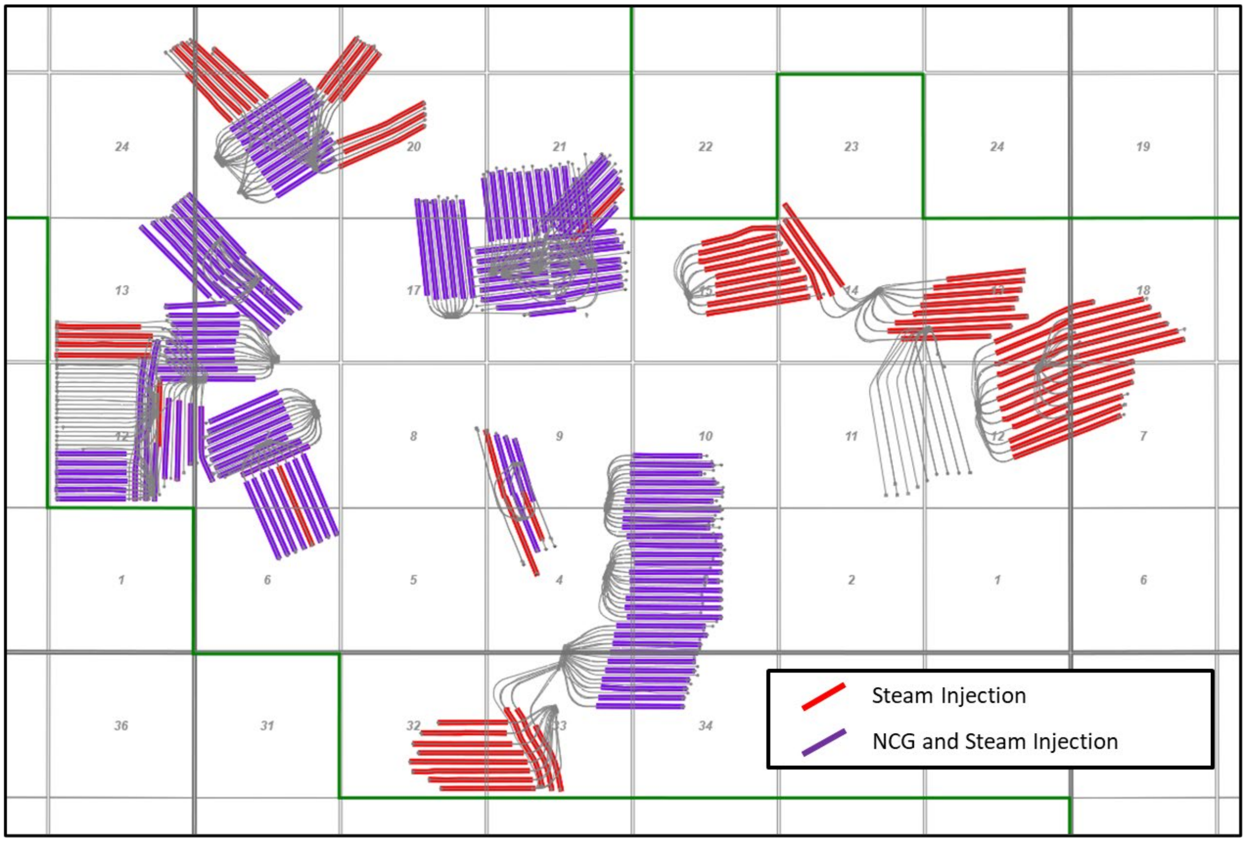


Figure 9 **iSOR, NCG injection concentration, and cSOR performance for MEG's Phase 1, Phase 2, and Phase 2B well patterns**

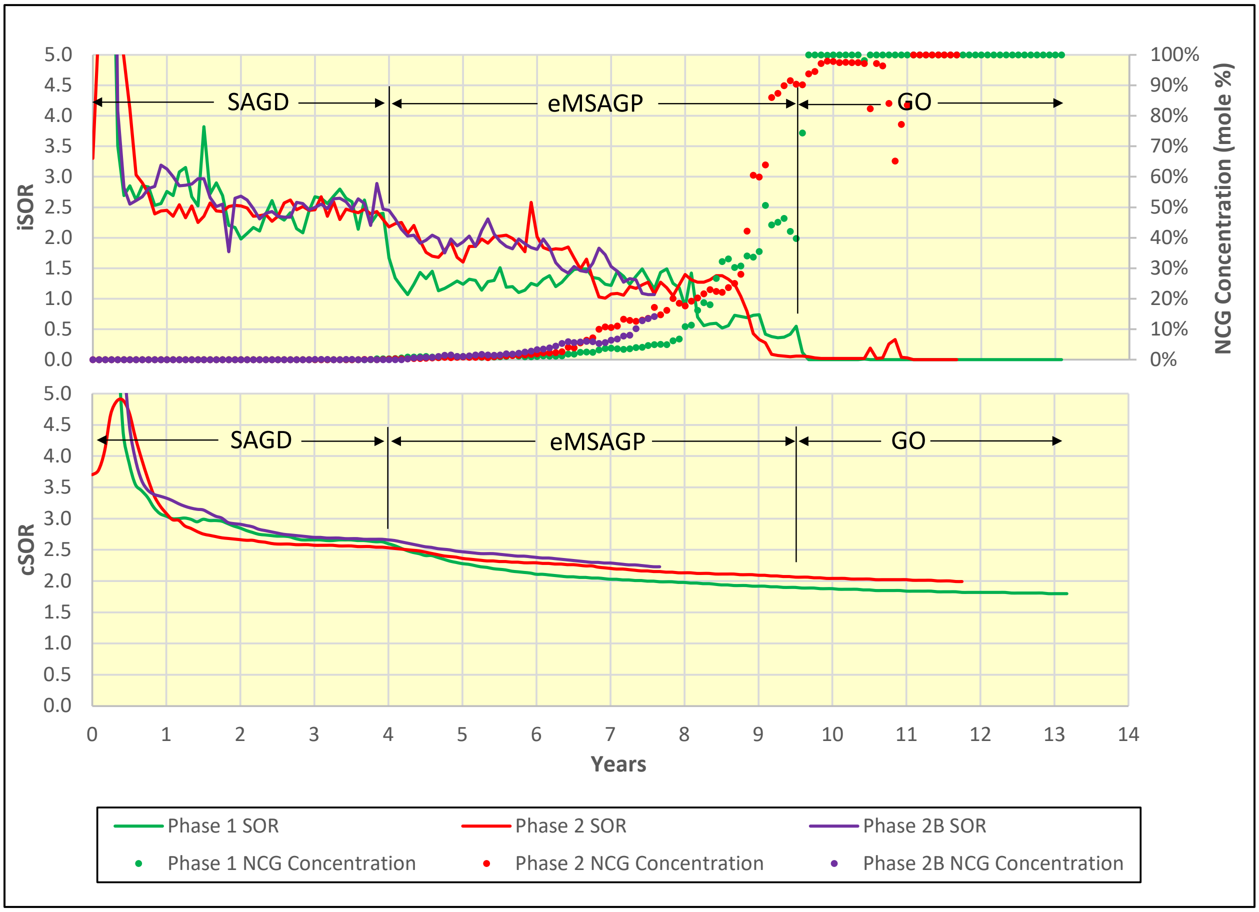


Figure 10 **Constructed and planned surface infrastructure within the development area**

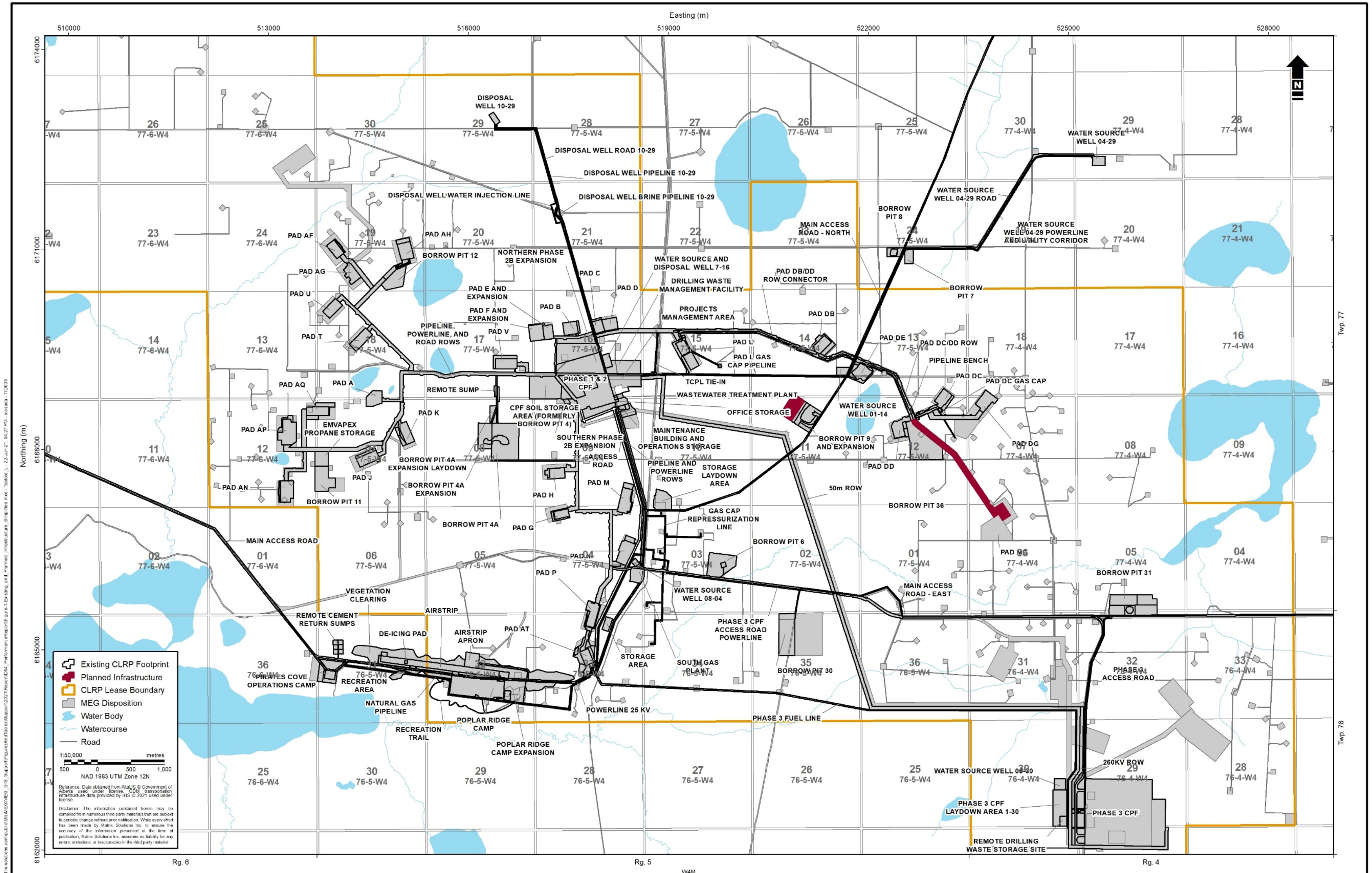


Figure 11 **Source and disposal wells within the development area**

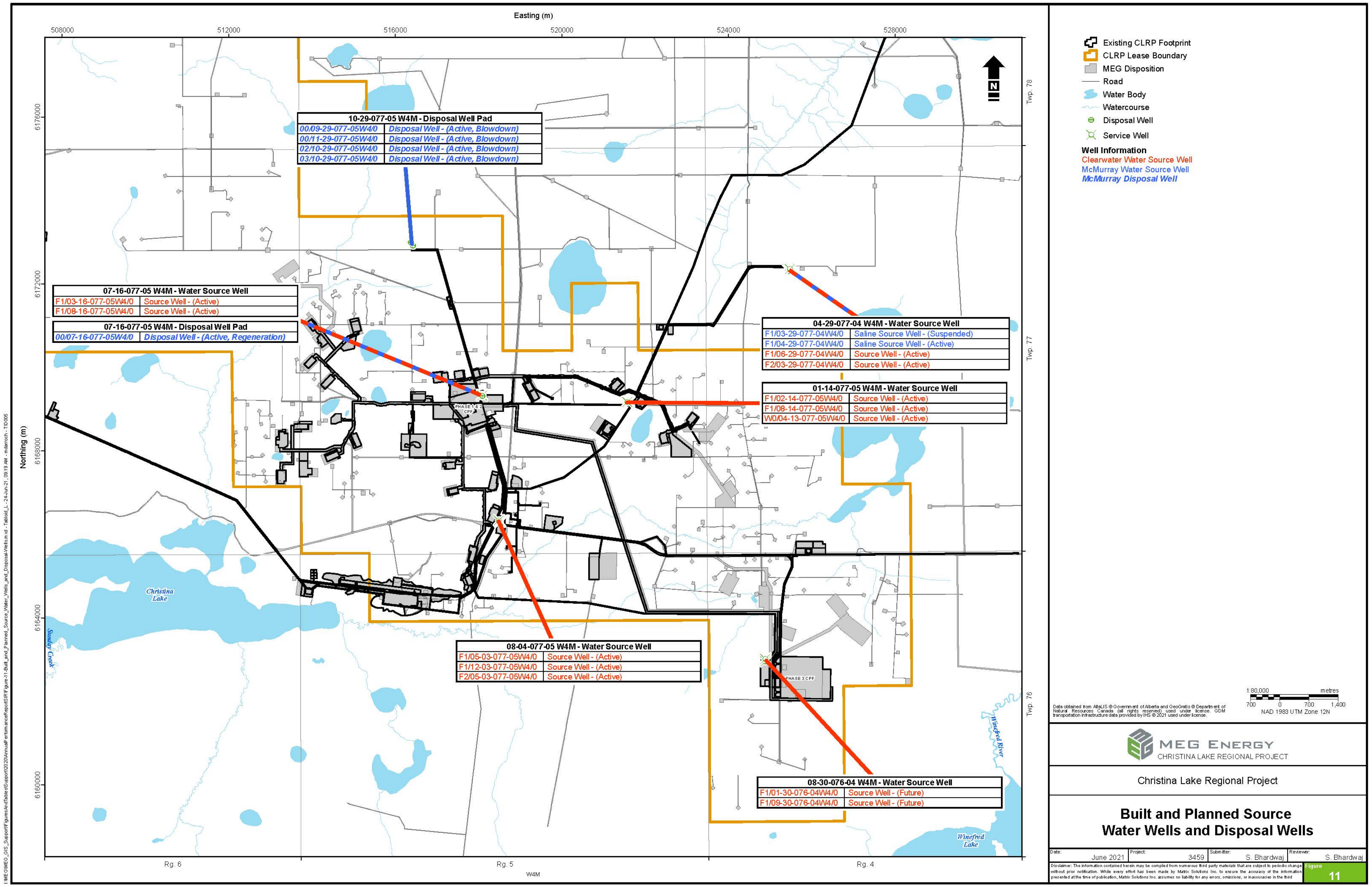


Figure 12 Facility Performance: Bitumen Treatment

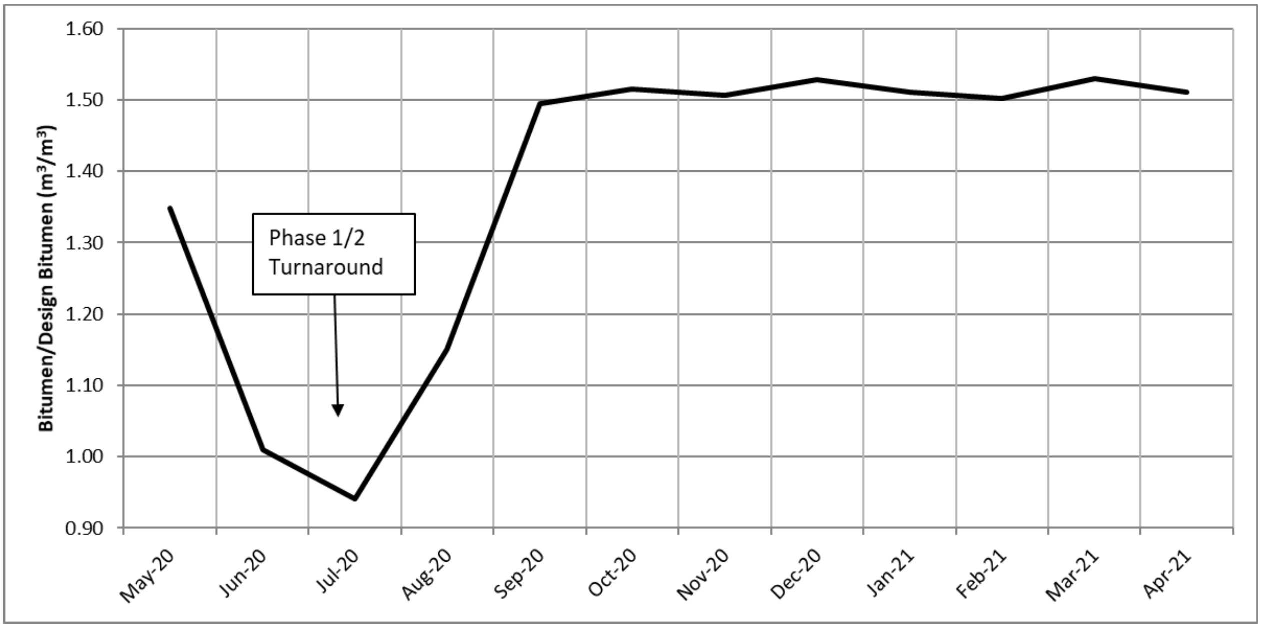


Figure 13 Facility Performance: Steam Generation

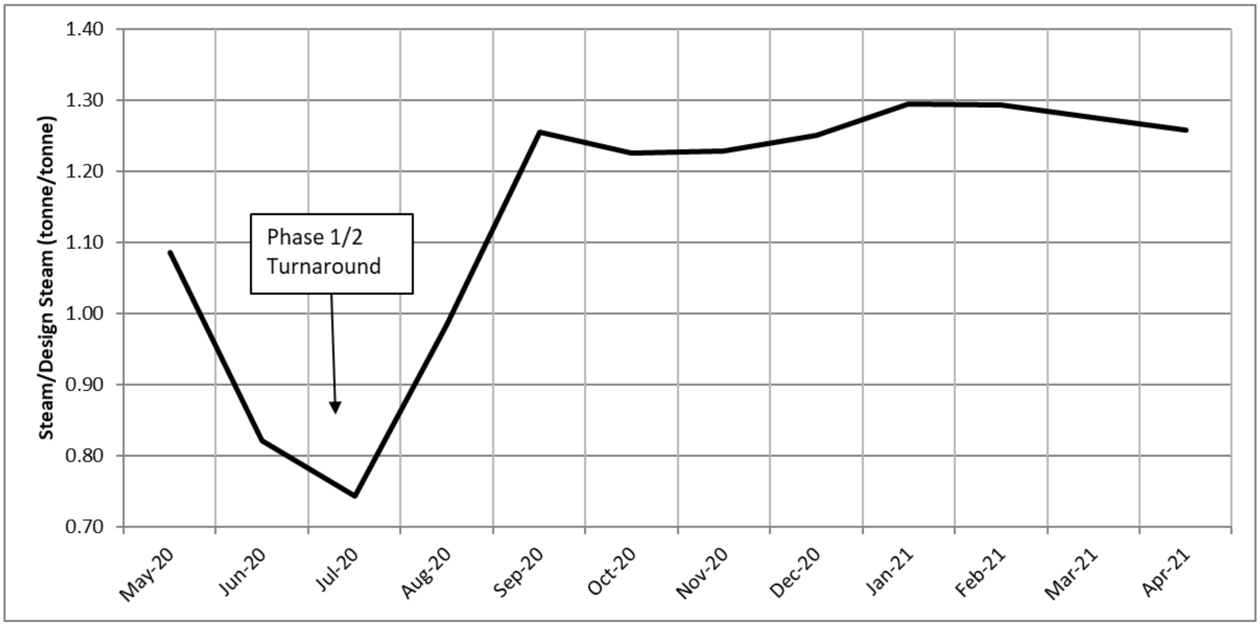


Figure 14 **Future planned development areas**