Christina Lake Regional Project
2021 Directive 54 Performance Report

Alberta Energy Regulator
Commercial Scheme Approval No. 10773

SUBMITTED TO:

Alberta Energy Regulator

SUBMITTED BY

MEG Energy Corp.

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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 2021, average daily bitumen production was 93,733 bbl/day with a steam-oil-ratio (SOR) of 2.43.

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	287,509,083	7%
Development Area	2,273,623,000		13%
Combined Active Well Pattern Area	817,851,000		35%

*Minimum Reservoir thickness of 10 m
** As of December 31, 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 horizonal permeability (Darcies)	5.0
Average vertical permeability (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.

On November 1, 2021, MEG received approval for fieldwide elevated cross-pattern injector wells drilled through existing patterns. The first cross pattern injector (AP14I) was completed on December 15, 2021 and began operating in January 2022. Performance information will be provided as part of the 2022 annual performance report.

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

Pattern	Area (m^2)	Net Pay Thickness (m)	Average Porosity	Average Oil Saturation	Permeability (D)	OBIP (m^3)	SBIP (m^3)	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%	3-6	3,898,000	3,673,000	57%	58%	60%	61%
Phase 2*	2,690,534	24.1	32.7%	78.4%	2-5	16,613,000	14,342,000	64%	65%	74%	75%
V	650,137	25.9	31.6%	73.7%	2-5	3,926,000	3,479,000	34%	~50%	38%	50-60%
G**	215,631	17.6	31.4%	73.0%	2-5	876,000	843,000	42%	50-60%	44%	50-60%
H**	66,813	19.1	32.6%	71.5%	2-5	298,000	228,000	49%	50-60%	64%	60-70%
J	781,677	21.1	32.7%	74.1%	3-6	3,999,000	3,653,000	23%	~50%	25%	50-60%
K**	672,726	21.2	32.6%	74.0%	3-6	3,447,000	3,224,000	42%	~50%	45%	50-60%
M	978,051	29.6	31.8%	79.0%	2-5	7,152,000	6,686,000	55%	60-70%	58%	60-70%
N	970,951	24.3	32.7%	79.8%	2-5	6,152,000	5,687,000	46%	50-60%	50%	60-70%
T	756,229	21	31.4%	81.5%	3-6	4,071,000	3,236,000	31%	~50%	39%	60-70%
U	454,179	25.2	30.8%	80.3%	3-6	2,834,000	2,649,000	41%	~50%	43%	50-60%
AP South	246,047	25	33.0%	78.3%	3-6	1,590,000	1,485,000	46%	60-70%	49%	60-70%
AF	498,601	19.9	32.4%	81.4%	2-5	2,609,000	2,110,000	42%	~50%	52%	60-70%
AG	414,226	21.5	32.7%	76.7%	2-5	2,235,000	2,095,000	38%	~50%	40%	50-60%
AN	776,936	26.3	32.6%	80.1%	3-6	5,339,000	4,804,000	52%	60-70%	58%	60-70%
P	1,269,292	20.2	31.6%	74.3%	2-5	6,030,000	4,955,000	34%	~50%	42%	60-70%
AQ	856,937	20.1	33.1%	79.5%	3-6	4,532,000	4,184,000	35%	50-60%	37%	60-70%
AT	1,228,181	27.5	31.2%	77.1%	2-5	8,120,000	7,233,000	23%	50-60%	25%	60-70%
L	946,741	23.4	33.0%	72.5%	3-6	5,286,000	4,571,000	24%	50-60%	27%	60-70%
DB	1,211,412	21.8	33.1%	68.0%	3-6	5,950,000	4,867,000	17%	50-60%	21%	60-70%
DC	1,035,394	24.4	32.0%	72.4%	3-6	5,860,000	5,022,000	14%	60-70%	16%	70-80%
DD	1,367,931	25.7	32.6%	70.3%	3-6	8,066,000	6,394,000	12%	~50%	15%	60-70%
AH	1,206,401	21.1	32.2%	79.4%	2-5	6,543,000	5,043,000	5%	50-60%	7%	70-80%
DE	979,190	20.5	33.0%	68.9%	3-6	4,545,000	3,662,000	2%	60-70%	3%	70-80%

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.
Resource values presented are based on MEG volumetric calculations and are not in accordance with National Instrument 51-101 guidelines

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. MEG uses natural gas (primarily methane) in it's NCG injection process.

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 shown positive results. Reservoir pressure targets have been successfully maintained by NCG co-injection. There is some indication of NCG leak off to bottom water zones in areas with bottom water connectivity. 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. Approximately 75 -

80% of co-injection NCG is recovered. 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. No negative impacts to well integrity due to co-injection have been observed.

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.

The CPF modifications in calendar year 2021 were:

1. Produced Gas Compressor

   Installation of a gas driven compressor to increase the plant produced gas reinjection capacity by 200 e^3Sm^3/d – completed in February 2021.

2. Drum Boiler

   Installation of two (2) drum boilers giving a total of 5200 t/d of steam capacity – completed in June 2021.

3. MVC – Mechanical Vapour Compressor

   Installation of a mechanical vapour compressor system to treat Once Through Steam Generator (OTSG) blowdown to produce the boiler feedwater (BFW) for the two drum boilers – completed in June 2021.

There have been no modifications to the CPF over the reporting period that have required an AER approval.

Figure 12 represents the annual actual operational bitumen treatment throughput relative to design rates. Figure 13 represents the annual actual operational steam generation throughput relative to design rates. 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, 9 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 of wells that have been suspended over the reporting period. At CLRP, there are currently no well patterns that have been abandoned. Note that AF3N will be re-activated following a successful workover in 2022.

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

Well Ref Number	API/UWI	Licence #	Licence Status
A5P	105/08-13-077-06W4/00	0351527	Suspended
A6P	102/08-13-077-06W4/00	0351528	Suspended
AF3N	113/09-19-077-05W4/00	0483792	Suspended
B1P	112/06-21-077-05W4/00	0374882	Suspended
B5P	105/08-21-077-05W4/00	0374886	Suspended
B7P	103/01-21-077-05W4/00	0445254	Suspended
B8N	113/08-21-077-05W4/00	0445273	Suspended
B8P	108/08-21-077-05W4/00	0445255	Suspended
B9N	112/07-21-077-05W4/00	0445274	Suspended
BB6I	102/01-21-077-05W4/00	0374826	Suspended
BB6P	100/01-21-077-05W4/00	0374887	Suspended
D5N	115/07-21-077-05W4/00	0449235	Suspended
D7P	102/06-16-077-05W4/00	0431416	Suspended
E2P	106/09-16-077-05W4/00	0374946	Suspended
F5N	120/05-21-077-05W4/00	0453087	Suspended
V6N	114/02-20-077-05W4/00	0460578	Suspended
V7N	105/07-16-077-05W4/00	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
1932420	Amendment application for subsurface modifications to pattern DG	24-Mar-2021
1932205	Amendment application to Sulphur Management Plan	31-Mar-2021
1933584	Amendment application to Sulphur Management Plan	02-Sep-2021
1934040	Amendment application for subsurface optimization (cross-pattern injection wells)	01-Nov-2021
1934610	Amendment application for CPF Sulphur Removal Unit expansion	08-Dec-2021
1934614	Amendment application for subsurface modifications to pattern MC	15-Dec-2021

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

- Commissioning and start-up of MVC Evaporator and Drum Boilers.
- Commissioning and start-up of brine disposal pipeline for process wastewater stream segregation.
- Commissioning and start-up of a 2nd produced gas recycle compressor.
- Completed the modification of blanket gas distribution in Phase 2B sales oil tanks resulting in a reduction in diluent flashing and pressure excursions in these tanks.
- On-going catalytic viscosity reduction pilot project.
- 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 opportunities to improve that were addressed at the CLRP over the reporting period include:

- On-going study to develop a virtual BTU analyzer for combustion tuning.
- Implemented automated HP steam pipeline pressure control through field injection to optimize steam usage and mitigate upsets.

Some opportunities to improve 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 CLRP 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 January 1, 2021, to December 31, 2021, 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, contraventions, and corresponding efforts provided in Tables 6 through 9, respectively. There were no voluntary self disclosures over this reporting period. 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 (e^3m^3)	Est. Duration (hrs)	H_2S Conc (ppm)	Reason	Details
31071860	2021-01-14	30	42	0	Planned Maintenance	Planned Flaring event. Residual propane in the storage was sent to the AP Pad flare stack.
31074459	2021-01-22	34	5	575	Emergency	Flaring due to eMVAPEX compressor package tripping on emulsion flow meter malfunction.
31086655	2021-02-03	20	4	550	Emergency	Flaring due to eMVAPEX recovery package compressors tripping due to a gas pressure swing from swapping wells in test.
31090429	2021-02-06	29	5	569	Emergency	Flaring over the 4-hr limit due to both eMVAPEX compressors tripping causing excess gas to come back to CPF.
31090595	2021-02-08	24	5	567	Emergency	Flaring due to swing in eMVAPEX solvent header pressure causing the compressors to trip on 1st stage pressure high.
31095558	2021-02-08	8	6	450	Emergency	Phase 2 VRU tripped due to low lube oil flow to first stage. This initially caused flaring that was reported (31091837) and then venting from the Phase 1 and 2 tank farm. After phase 2 Skim Tank PSV lifted to control the pressure, intermittent venting of gas from 7 tanks occurred.
31091837	2021-02-09	7	6	50	Emergency	Phase 2 VRU tripped due to oil supply issues causing tanks to breathe to the Phase 1 LP Flare.
31099016	2021-02-17	57	17	557	Emergency	Phase 2 LP BFW pumps tripped on high vibrations resulting in tripping the Phase 2 OTSG, Phase 2 GT/HRSG and both Produced Gas Compressors, causing excess flaring.
31184357	2021-03-27	6	6	300	Emergency	Flaring over the 4-hr limit due to both eMVAPEX compressors tripping causing excess gas to come back to CPF.
31189253	2021-03-30	34	4	500	Emergency	eMVAPEX compressors tripped twice causing flaring at the 2B plant. eMVAPEX Recovery package tripped due to "Rod Load" on compressor "A" which took down "B" compressor as well.
31189278	2021-03-31	193	7	350	Emergency	Flaring due to cascading operations from Phase 2B Inlet separator reaching high level. Make up valves in the fuel gas system unable to maintain pressure drop caused the Phase 2B GTG, all 4 Phase 2B OTSG's, Phase 1 OTSG and Plant 8 to trip, sending gas to flare.
31186447	2021-04-07	1	6	1500	Planned Maintenance	Planned flaring for the eMVAPEX outage. N_2 was used to purge the equipment during maintenance.
31234904	2021-05-26	54	8	600	Emergency	Flaring event due to DCS analog card failure which caused Phase 2B process and steam plants to experience trips.
31250887	2021-06-09	13	6	450	Emergency	Produced Gas compressors A & B tripped causing flaring on Phase 2B HP Flare.
31254481	2021-06-09 to 06-14	65	128	700	Emergency	Phase 2 VRU tripped due to liquid carryover. Flare due to a significant amount of work to restore the VRU to service.
31257943	2021-06-09 to 06-14	21	130	700	Unplanned Maintenance	Initial flaring event reported from notification above (31254481) cascaded to venting from the Phase 1 and 2 tanks.

31261129	2021-06-22	56	9	600	Emergency	Flaring due to the loss of 2 phases on the high voltage line that feeds the east well pads resulting in loss of the ESP's, steam and instrument air.
31297804	2021-08-01	15	24	700	Planned Maintenance	Planned Flaring due to VRU outage need to upgrade the scrubber drain pumps to the unit.
31311070	2021-08-05	2	9	200	Emergency	Lightning strike caused the loss of the majority of the pads and reduced emulsion flow to the plant. This caused the need to send gas to flare until conditions stabilized.
31311021	2021-08-05	32	14	450	Emergency	Lightning strike caused the loss of the majority of the pads and reduced emulsion flow to the plant. This caused the need to send gas to Phase 2B flare stack until conditions stabilized
31341301	2021-09-01	32	5	325	Emergency	OTSG A tripped on low O_2 causing a high-pressure flare exceedance.
31382344	2021-10-08	10	5	450	Emergency	MVC tripped while performing PM on VFD cooling HVAC unit. Trip of MVC resulted in ramping back drum boiler load due to limited BFW tank capacity and flaring of produced gas.
31456508	2021-12-02	59	68	700	Planned Maintenance	Planned VRU maintenance outage. Tank gas had to be sent to the flare stack for the duration of the outage.

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
20200304	2021-01-06	02-16-077-05W4	Lime sludge	10	0.8	Facility	The hose on the top of the Phase 2B Hot Lime Softener (HLS) failed at the camlock fitting and started spilling lime sludge down the side of the vessel on to the ground below.	A review of the hose with the vendor to ensure the material and components are compatible with the HLS products and determined that the hose material used has adequate strength to hold itself when full of fluid. Developed a PM to have the hoses on the Phase 1, 2 and P2B HLS's switched out every 90 days. Applicable job plans updated to formalize inspection of the in-service hoses as part of the regular operator rounds.
20200312	2021-01-06	15-12-077-05-W4	Emulsion	0.04	N/A	Pipeline	During an annual pipeline inspection, it was discovered approximately 40L of emulsion leaked from drain valve to the frozen ground below. (Off-lease - reportable)	Continue with winterization and freeze reporting program. Pipeline inspections will continue to be a priority. Remove the emulsion bypass flowlines from service.
20200521	2021-09-10	02-16-077-05W4	Hydrochloric Acid	0.05	N/A	Facility	While off-loading hydrochloric acid approximately 50 L leaked out of the PSV on to the ground below the truck.	A meeting was held with the transport company to review loading-offloading procedures and requirements.
20200832	2021-09-24	02-16-077-05W4	Regen Waste Water	4.2	N/A	Facility	Neutralization pump experienced an internal failure of the containment shell in the pump resulting 4.2 m^3 of wastewater being released to the floor and trenches of Phase 2B Water Treatment Building.	A new pump was installed. An investigation was conducted and there was no early sign of a leak during rounds. This pump design is a robust design to prevent leak detection. The reliability of the pumps will continue to be reviewed.
20201549	2021-12-05	02-12-077-06W4	Emulsion	817	37	Facility	Service rig was preparing infill well AN5N for future re-entry and well control was lost during well servicing. Release volume breakdown was 65 m^3 bitumen, 117 m^3 produced water/ condensed steam, 635 m^3 kill fluid (BFW and produced water supplied from the CPF).	Minimum volumes to be applied to wells have been increased to ensure adequate volumes are used for each well. Updated the well kill matrix to include clear instructions for injection volumes and trickle control rates. Updated well servicing program to include additional pertinent well information and well kill procedures specific to the well. Provided enhanced thermal well control training to staff.

Table 8. Contraventions over the reporting period

AER ID	Type	Date	Location	Details	Corrective Action
381260	Unauthorized release	2021-07-14	02-16-077-05W4	The Phase 1 OTSG blowdown outlet piping diffuser corroded and multiple holes and leak points were identified on the diffuser located above the concrete apron that drains into the process pond. Un-authorized release of facility wastewater to the run off pond.	Sandbags were placed to help prevent backflow of fluids on to the apron. Proactive inspections are part of the plan of the Corrosion Management System. The repair of this location has been completed.
381885	Incomplete Report	2021-07-29	02-16-077-05W4	Passive Station #1 was discovered to have a damaged SO_2 sampler at the time of monthly collection. The required analysis was not able to be completed on the sampler. This contributed to a reporting deficiency and contravention of the EPEA approval in the monthly air report.	Passive stations have signage and gates around them to protect the sample stations from damage as much as possible. A cause for the damage could not be determined.
384549	AAAQO Limit Exceedance	2021-10-13	02-16-077-05W4	Third Party air monitoring was on site collecting H_2S monitoring data related to the MVC vent. A 1-hr H_2S limit exceedance of 10.6 ppb was observed with the air monitoring equipment at the north boundary of the CPF (AAAQO hourly limit is 10.0 ppb).	Engineering is currently planning on tying in the MVC vent to the VRU to eliminate the vent source.
386756	NOx 1-hr Limit exceedance	2021-12-20	02-16-077-05W4	Phase 2B Drumboiler Stack A 1-hr NOx limit exceedance in the 23:00 hour. The 1-hr average = 8.73 kg/hr. Approval Limit is 8.2 kg/hr. There appeared to a be a possible issue with plugging of the fuel gas regulator.	Audible alarm setup for panel operator for both AER & federal NOx limits. Completed boiler tuning. Fuel gas regulator plugging short term mitigation is to drain the drip leg on the fuel gas train on a frequent basis, reducing the fouling on the regulators. Long term project is to add a separation vessel to Plant 8 to eliminate liquids issue. Will come online in Q1 2023. Increase visibility for panel operators by having NOx on main panel – in progress.

Table 9. 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.
Contraventions	• When required, corrective actions or mitigations are identified and implemented. • 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 and fully 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. Phase 2B produced water exchangers are planned for commissioning in early 2023. Additional Phase 2B glycol aerial coolers will be installed in Phase 2B to assist in cooling demand associated with higher throughput during the summer months. No other significant plant modifications are anticipated; however, MEG is continuously assessing optimization options aimed at enhancing overall performance.

A fifth disposal well will be added at the 10-29-077-05 W4M disposal well pad to increase the disposal system operation reliability going forward.

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

FIGURES

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

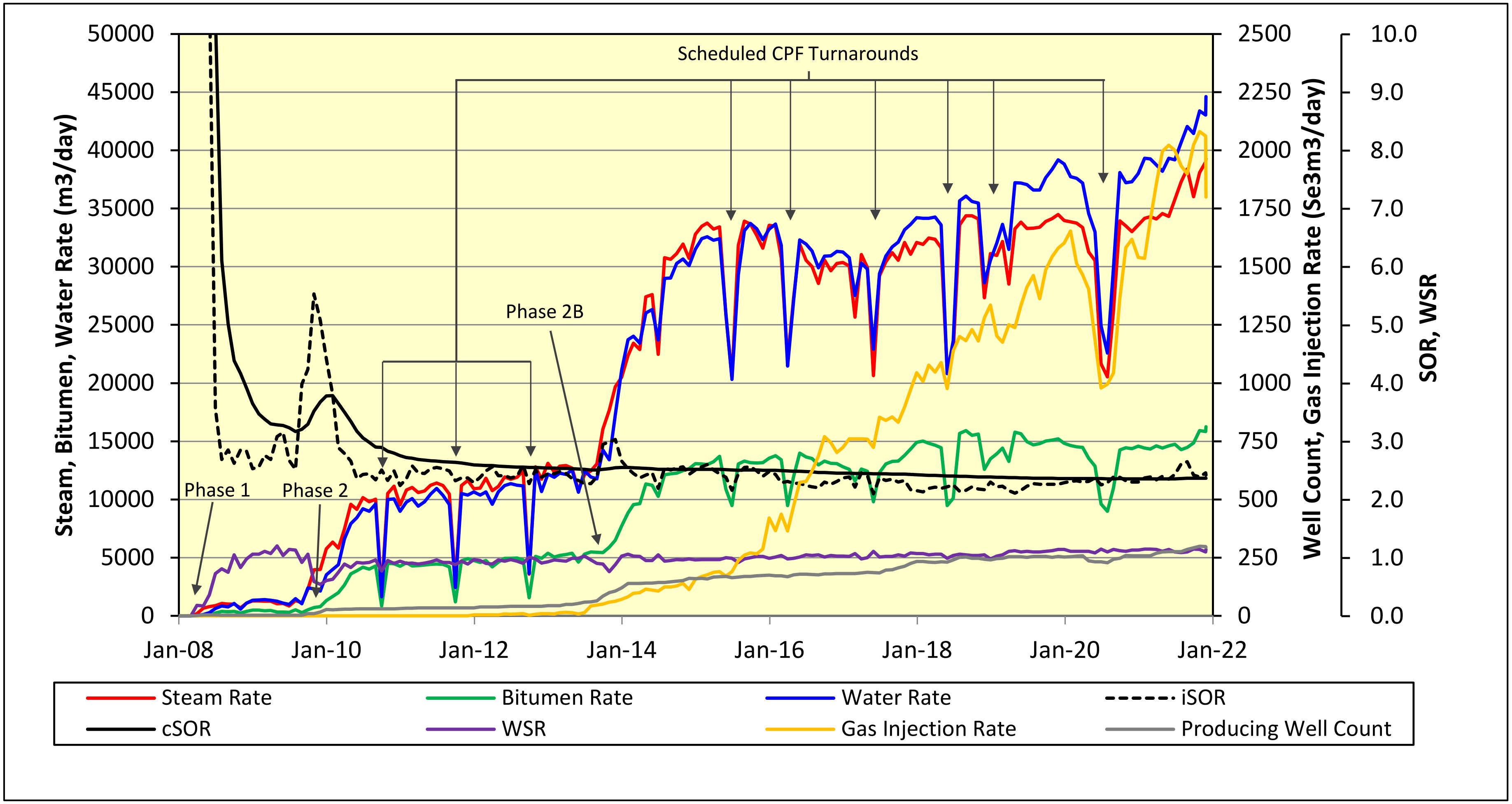
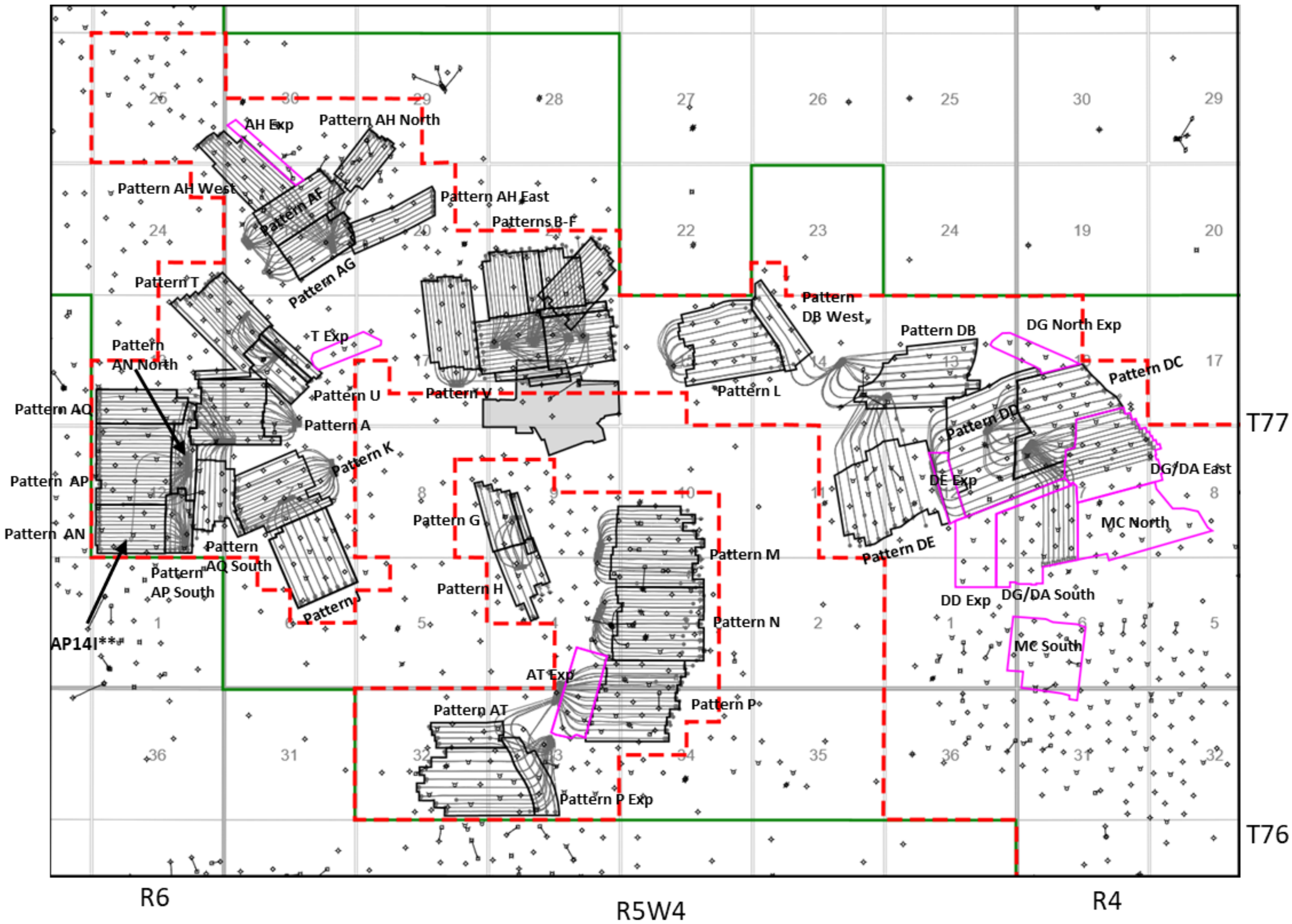


Figure 2 **Drilled and approved drainage pattern areas**



MEG OSL

Approved Development Area

Approved Patterns

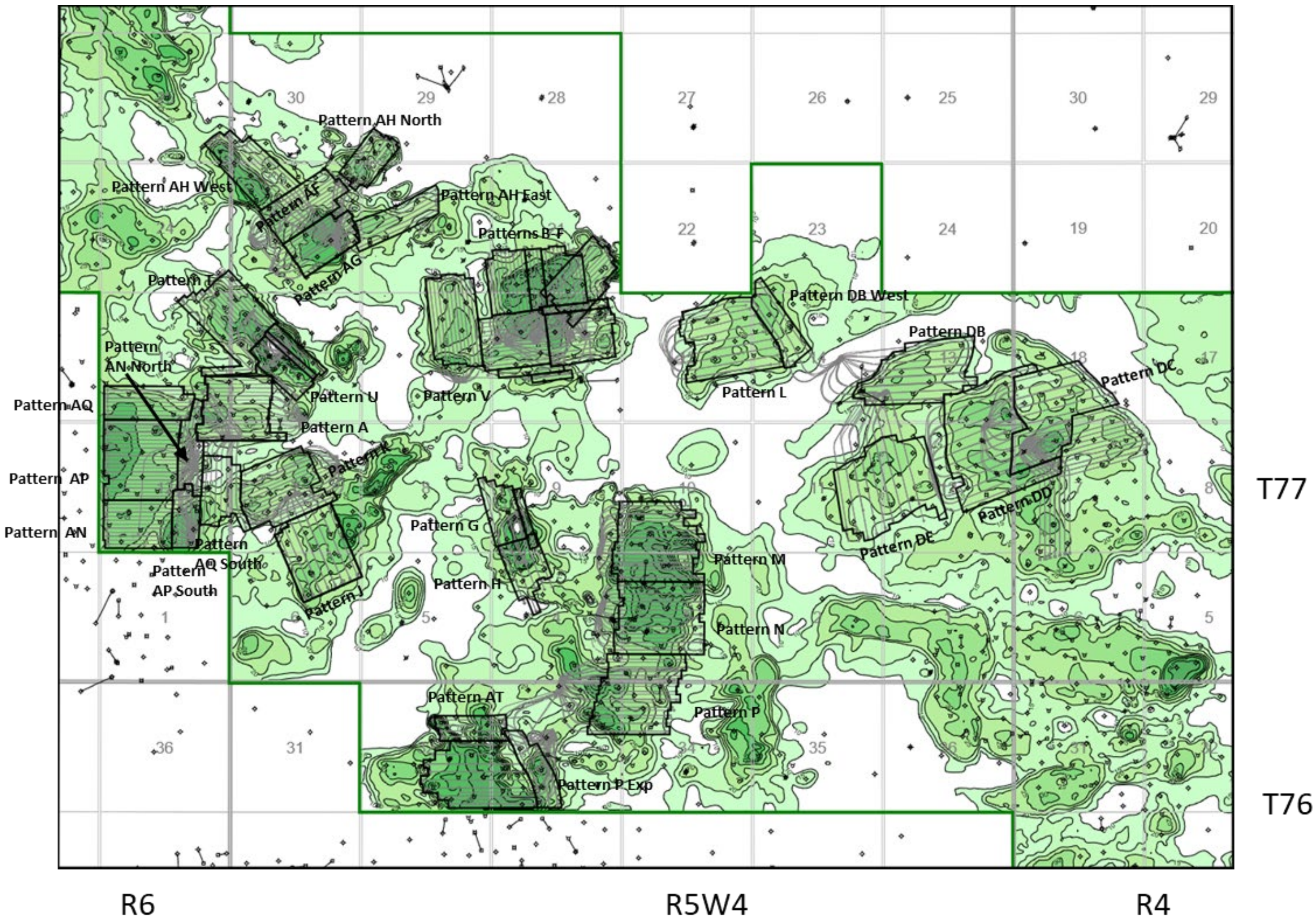
Central Plant

*As of Dec 31, 2021

**AP14I (cross pattern injector) drilled but not operated in 2021

***DE pattern has 9/11 well pairs drilled

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**

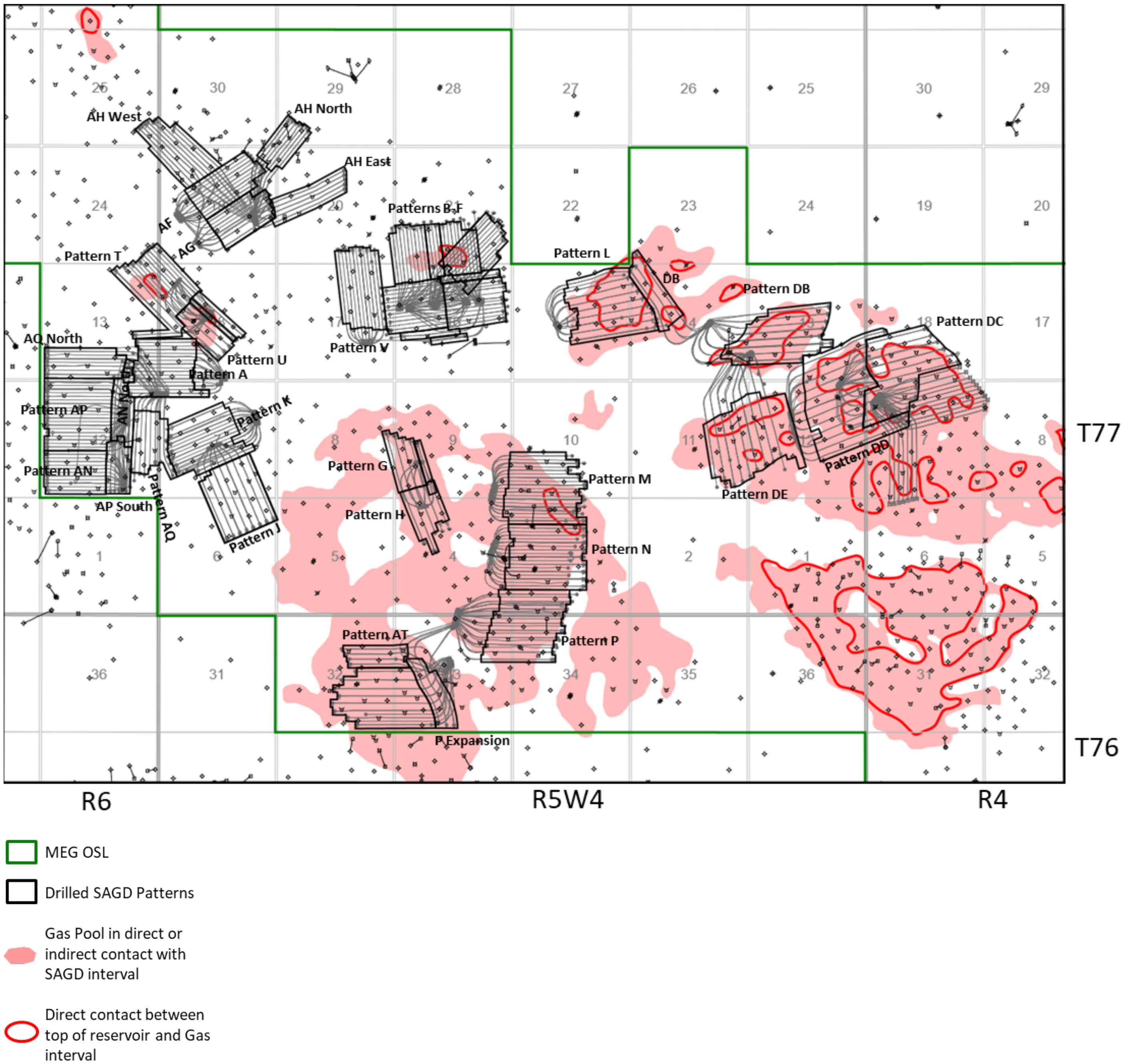


Figure 5 **Net basal water isopach in communication with pay**

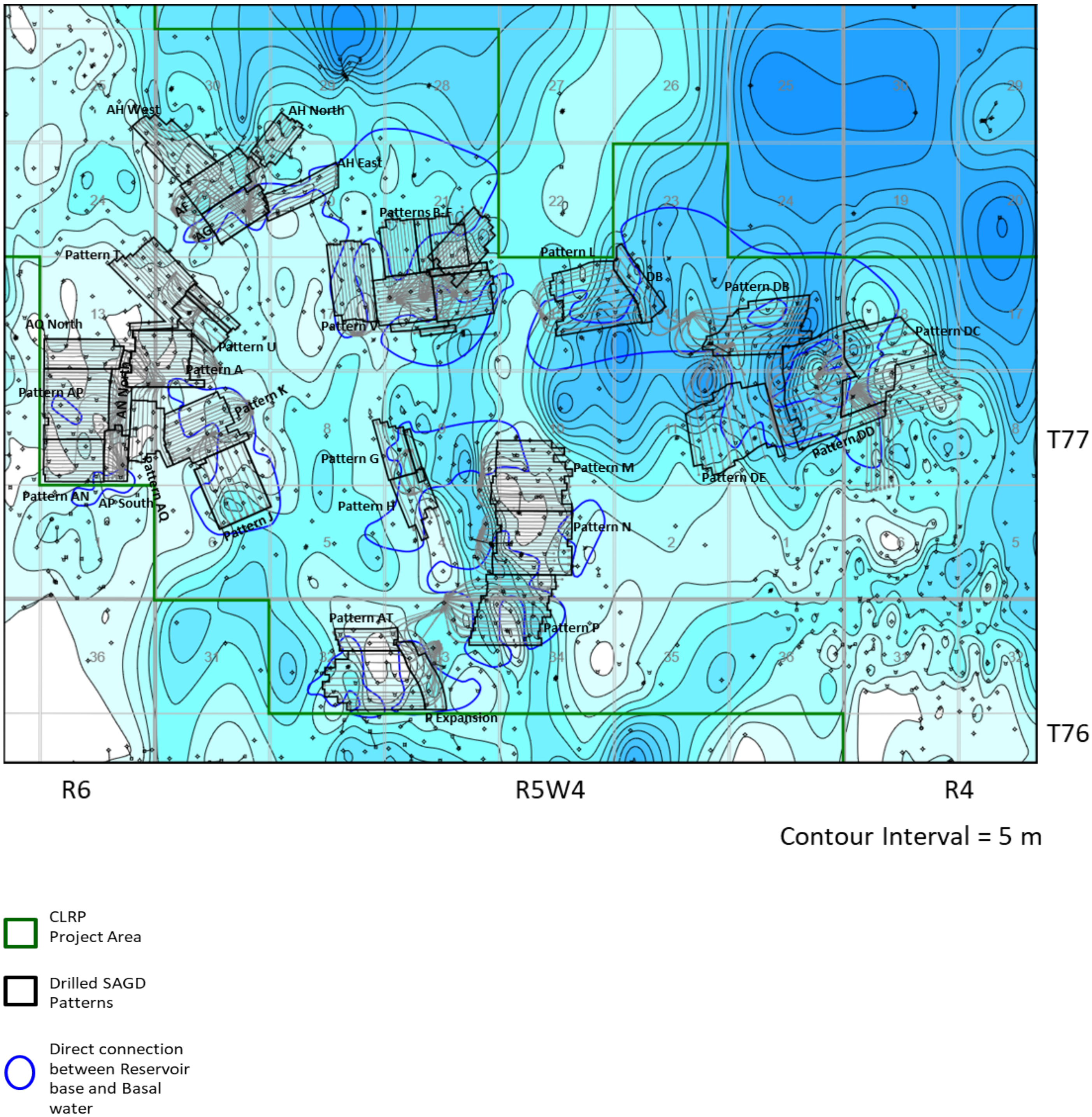


Figure 6 **Seismic acquisition in the project area**

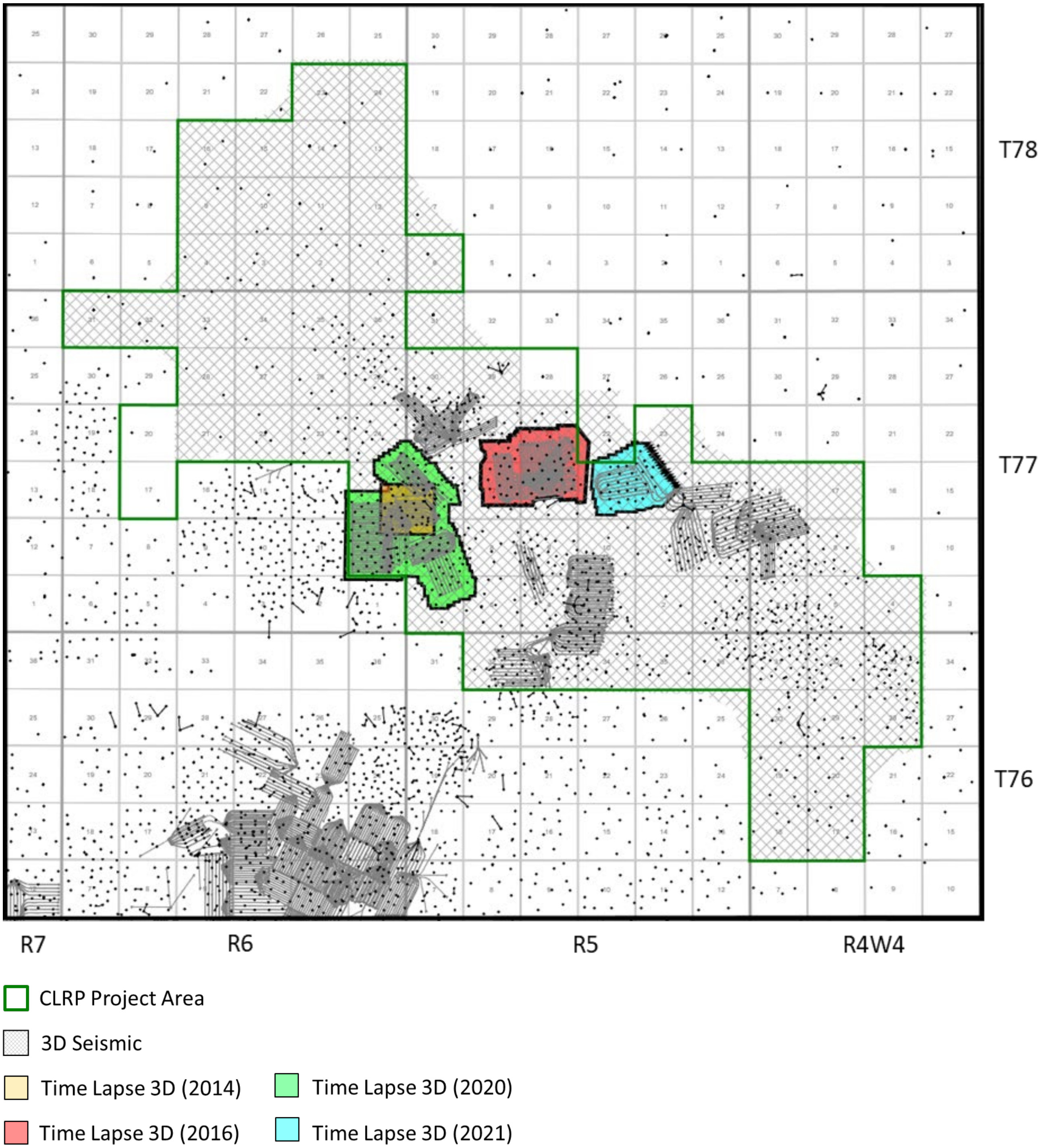
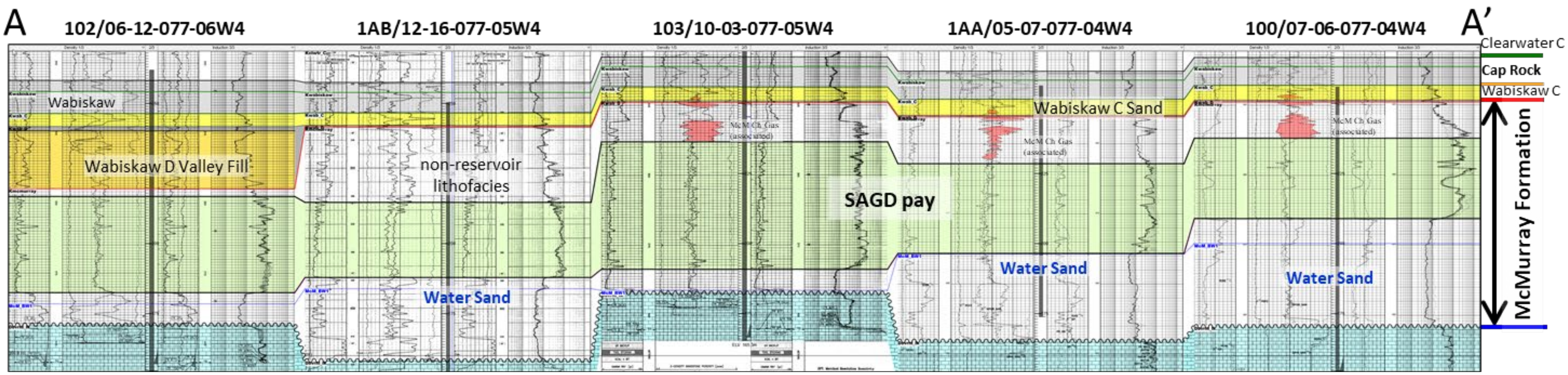


Figure 7 **Representative cross section within the active development area**



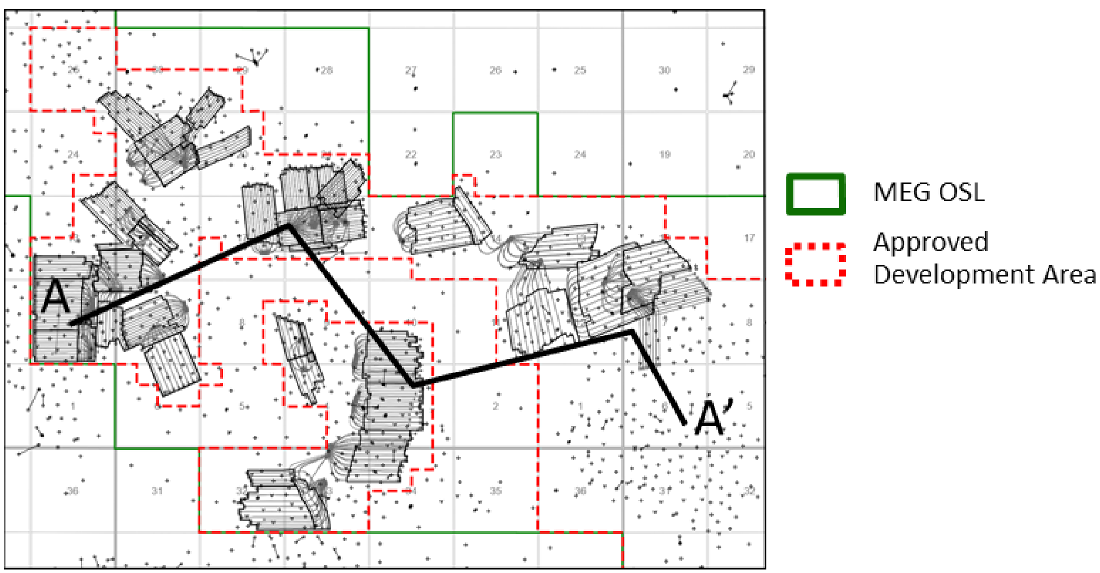


Figure 8 Injection wells by type as of December 31, 2021

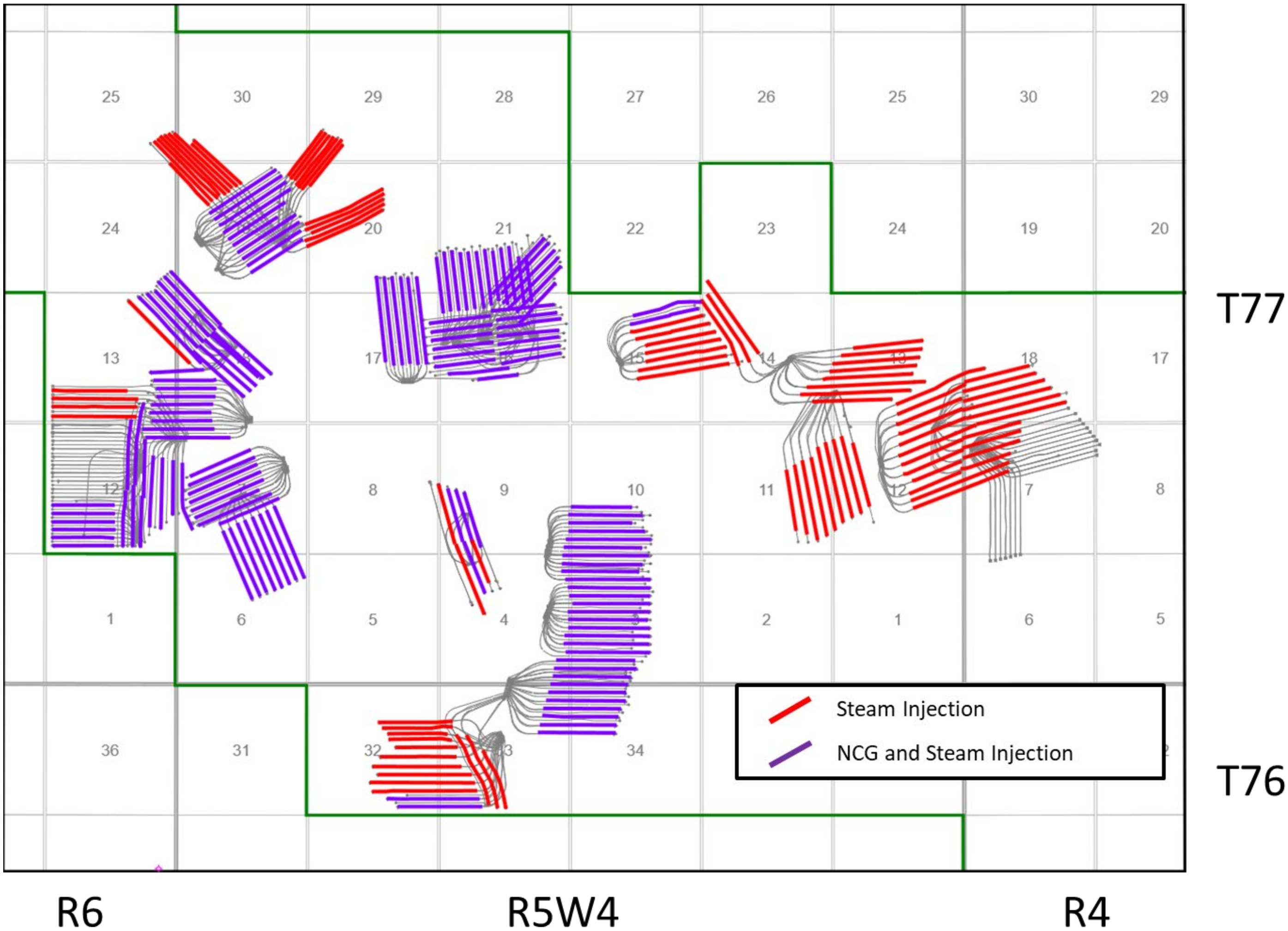


Figure 9 **iSOR, NCG injection concentration, and cSOR performance for MEG's Phase 1, Phase 2, and Phase 2B well patterns**

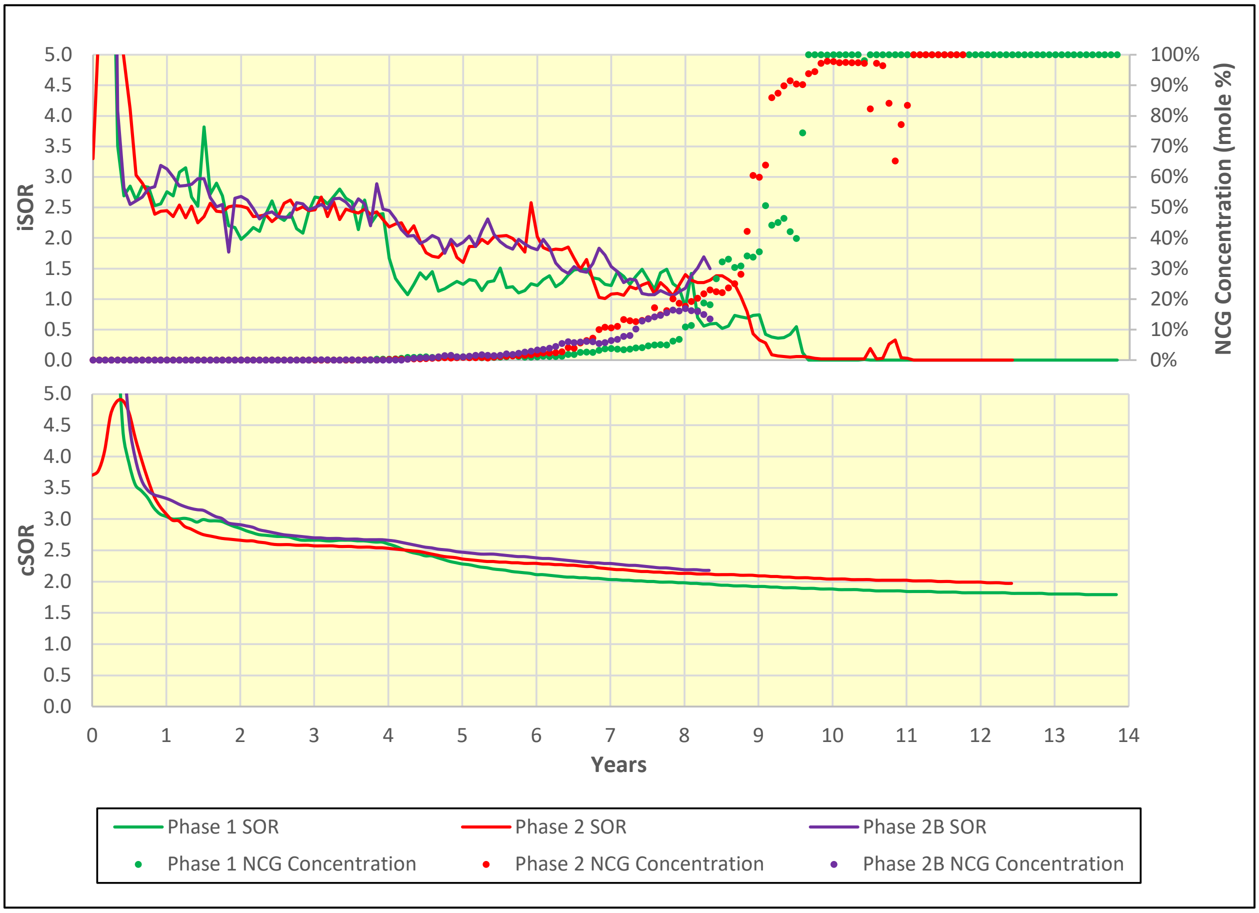


Figure 10 Constructed and planned surface infrastructure within the development area

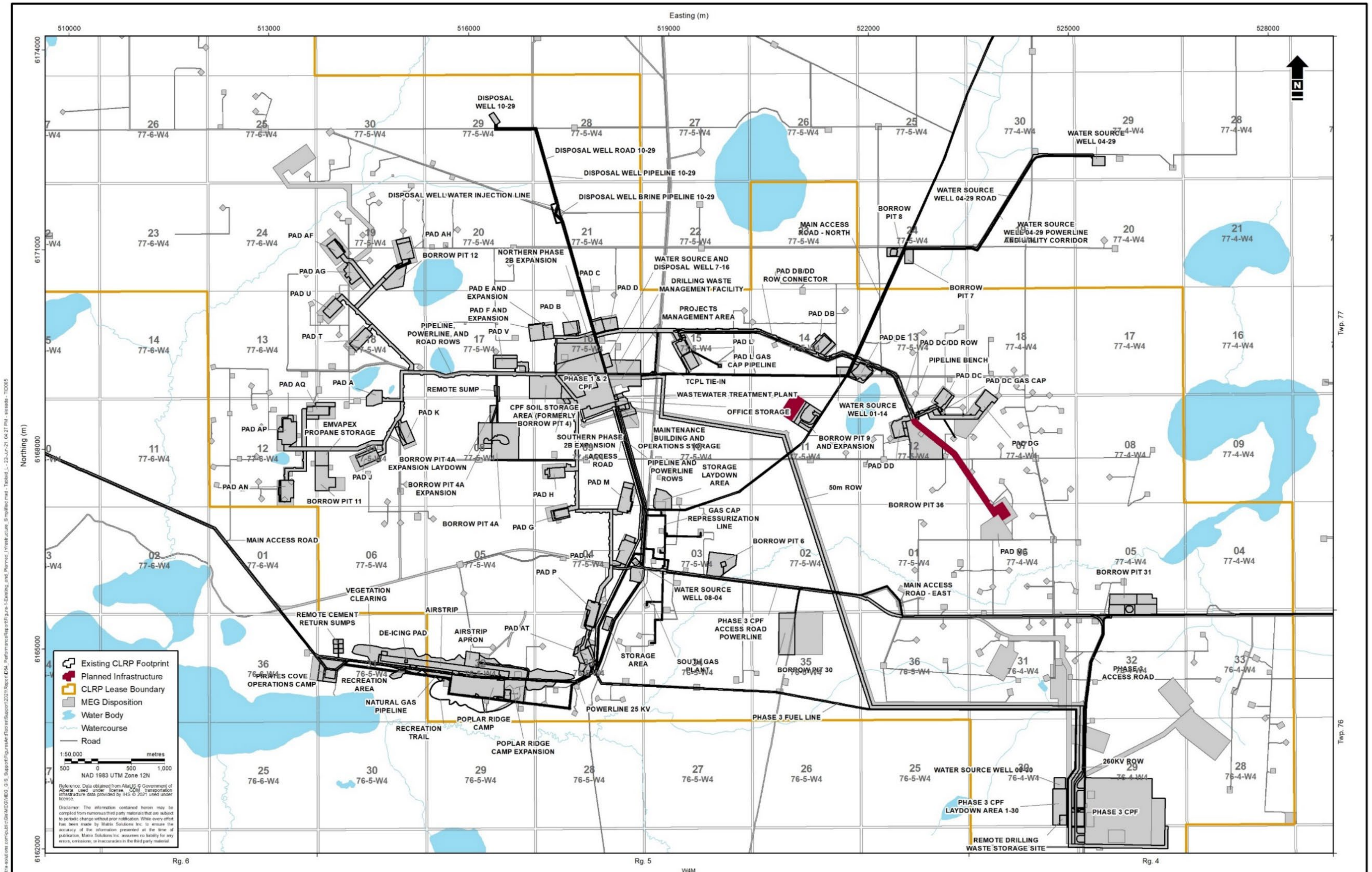


Figure 11 **Source and disposal wells within the development area**

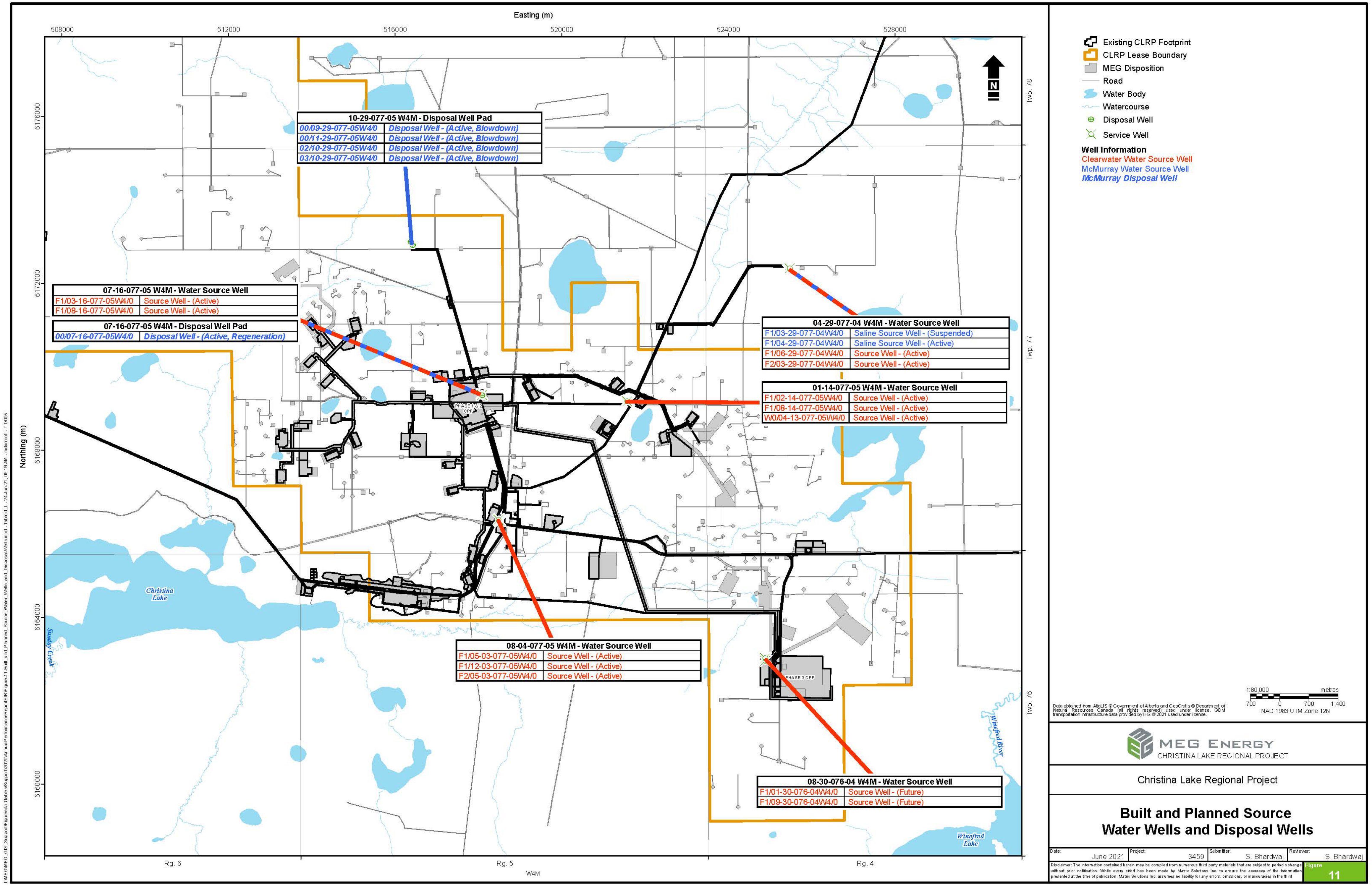


Figure 12 Facility Performance: Actual vs. Design Bitumen Treatment Throughputs

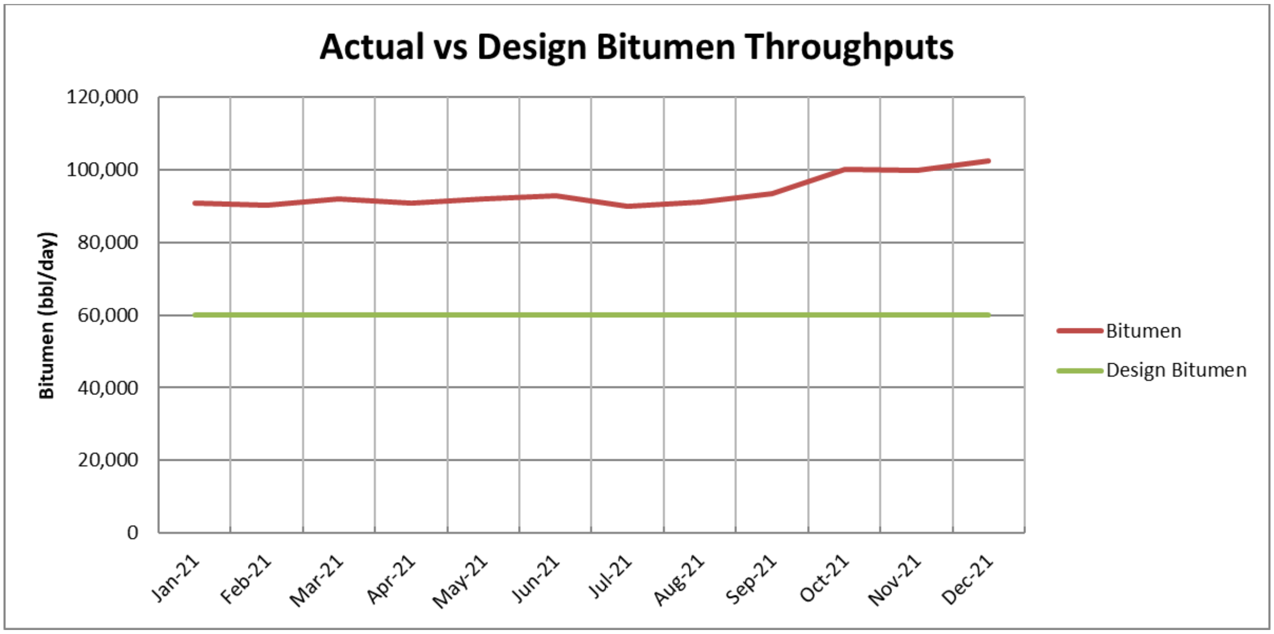


Figure 13 **Facility Performance: Actual vs. Design Steam Generation Throughputs**

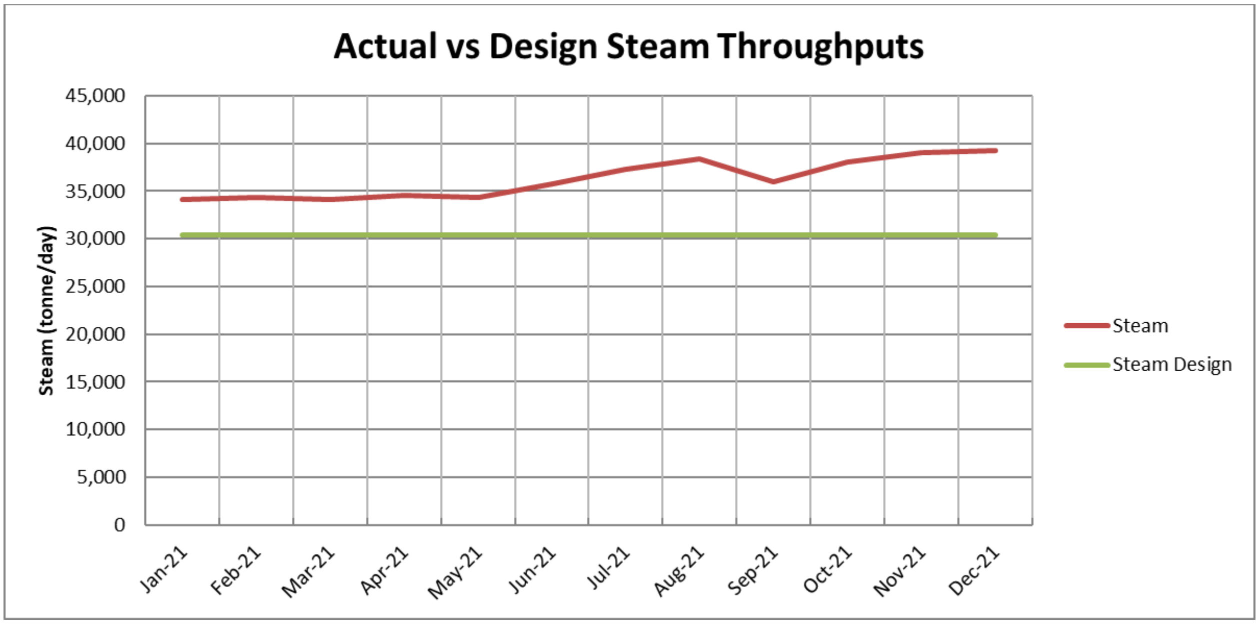


Figure 14 Future planned development areas