Christina Lake Regional Project
2022 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. 216466-01-05.

In 2022, average daily bitumen production was 95,349 bbl/day with a steam-oil-ratio (SOR) of 2.36.

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
- 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	4,228,792,000	322,247,000	8%
Development Area	2,246,449,000		14%
Combined Active Well Pattern Area	871,088,000		37%

*Minimum Reservoir thickness of 10m

** As of Dec 31, 2022

Resource values presented are based on MEG Volumetric calculations and are not in accordance with Natiuonal Instrument 51-101 guidelines

Table 2. Typical Reservoir Parameters within the Development Area

Development area Reservoir Parameters	
Average Pay Height (m)	24
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

Well pattern specific information including 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. AP14I was drilled approximately 10 m above the existing injectors to directly heat/mobilize the thickest section of bypassed pay (AP4P to AN6N), producing the oil out of the underlying production wells. To date, MEG has seen a 4% increase in the recovery factor with production increasing from 500 to 2,000 bbl/day. The forecasted cSOR in 2023 is 2.3 and existing wells below AP14I are showing increased mid-well temperatures, indicating growing connection with AP14I steam chamber.

As a result of the positive performance to date, MEG will be evaluating other workover options to enhance production of mid-well pay and other opportunities to improve depletion in upper pay using cross pattern injectors.

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	Permeability (D)	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%	3-6	3,898,000	3,673,000	57%	57%	61%	61%
Phase 2*	2,690,534	24.1	32.7%	78.4%	2-5	16,613,000	14,342,000	64%	65%	75%	75%
V	650,137	25.9	31.6%	73.7%	2-5	3,926,000	3,479,000	35%	~50%	39%	50-60%
G**	215,631	17.6	31.4%	73.0%	2-5	876,000	843,000	45%	50-60%	46%	50-60%
H**	66,813	19.1	32.6%	71.5%	2-5	298,000	228,000	53%	60-70%	69%	70-80%
J	781,677	21.1	32.7%	74.1%	3-6	3,999,000	3,653,000	24%	~50%	26%	50-60%
K**	672,726	21.2	32.6%	74.0%	3-6	3,447,000	3,224,000	43%	~50%	46%	50-60%
M	978,051	34.7	31.9%	78.4%	2-5	8,486,000	8,061,000	49%	60-70%	51%	60-70%
N	970,951	26.5	32.8%	79.6%	2-5	6,721,000	6,262,000	44%	60-70%	47%	60-70%
T	756,229	21.0	31.4%	81.5%	3-6	4,071,000	3,236,000	33%	~50%	42%	50-60%
U	454,179	25.2	30.8%	80.3%	3-6	2,834,000	2,649,000	44%	50-60%	47%	50-60%
AP South	246,047	25.0	33.0%	78.3%	3-6	1,590,000	1,485,000	59%	60-70%	63%	70-80%
AF	498,601	19.9	32.4%	81.4%	2-5	2,609,000	2,110,000	43%	50-60%	54%	60-70%
AG	414,226	21.5	32.7%	76.7%	2-5	2,235,000	2,095,000	42%	50-60%	45%	50-60%
AN	776,936	26.3	32.6%	80.1%	3-6	5,339,000	4,804,000	55%	60-70%	61%	60-70%
P	1,269,292	20.2	31.6%	74.3%	2-5	6,030,000	4,955,000	38%	50-60%	47%	60-70%
AQ	856,937	20.1	33.1%	79.5%	3-6	4,532,000	4,184,000	40%	60-70%	44%	60-70%
AT	1,228,181	29.6	31.3%	78.1%	2-5	8,901,000	7,996,000	28%	60-70%	31%	70-80%
L	946,741	23.4	33.0%	72.5%	3-6	5,286,000	4,571,000	32%	50-60%	37%	60-70%
DB	1,211,412	21.8	33.1%	68.0%	3-6	5,950,000	4,867,000	23%	50-60%	28%	50-60%
DC	1,035,394	24.4	32.0%	72.4%	3-6	5,860,000	5,022,000	22%	60-70%	25%	70-80%
DD	1,367,931	25.7	32.6%	70.3%	3-6	8,066,000	6,394,000	16%	50-60%	20%	60-70%
AH	1,206,401	21.1	32.2%	79.4%	2-5	6,543,000	5,043,000	19%	50-60%	24%	60-70%
DE	979,190	20.5	33.0%	68.9%	3-6	4,545,000	3,662,000	10%	60-70%	12%	70-80%
DG	1,079,821	21.7	32.6%	75.6%	3-6	5,780,000	4,736,000	5%	60-70%	6%	70-80%

*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 Natiuonal 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. 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.

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. 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. NCG co-injection results in increased produced gas rates as 75-80% of the injected gas is produced back from the reservoir and recovered. Consequently, additional gas sweetening units and re-compression packages are 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

Figure 10 is a map of the development area that includes constructed and planned surface infrastructure. Figure 11 is a map of the development area that shows all current source and disposal wells.

The CLRP modifications in calendar year 2022 were:

1. Disposal Well E – An additional disposal well was commissioned on the existing 10-29 well pad.
2. DG Pad Startup – 18 SAGD well pairs were put into service.
3. Phase 2B Emulsion Pump Modifications – Installed new impellers and a control valve in the Phase 2B inlet separation area. This allows for a higher emulsion transfer capacity.

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. Bitumen production performance over the original design is primarily due to facility modifications.

Figure 13 represents the annual actual operational steam generation throughput relative to design rates. Steam performance over original design is primarily due to increased reliability, re-rating of fired equipment, and installation of additional steam generators.

4 HISTORICAL AND UPCOMING ACTIVITY

4.9 Suspension and Abandonment

In the 12-month reporting period, 5 SAGD production wells, 13 SAGD injection wells and 4 infill production wells were suspended. Additionally, there were 22 wells abandoned to meet the AER mandatory spend for the liability reduction program. No SAGD well patterns were abandoned, and no SAGD 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. Table 5 presents a list of wells that have been abandoned over the reporting period.

Table 4. List of Wells with Licence Status Changed to Suspended

Well Ref Number	API/UWI	Licence #	Licence Status
E2I	102/09-16-077-05W4/00	374804	Suspended
C1I	100/08-17-077-05W4/00	374815	Suspended
F3P	114/05-21-077-05W4/00	374860	Suspended
F4P	115/05-21-077-05W4/00	374861	Suspended
F5P	116/05-21-077-05W4/00	374862	Suspended
C1P	103/08-17-077-05W4/00	374876	Suspended
F1I	105/16-16-077-05W4/00	374956	Suspended
F3I	111/05-21-077-05W4/00	374958	Suspended
F4I	110/05-21-077-05W4/00	374959	Suspended
F5I	109/05-21-077-05W4/00	374960	Suspended
D6I	100/05-16-077-05W4/00	431441	Suspended
D7I	103/06-16-077-05W4/00	431442	Suspended
V6I	104/02-20-077-05W4/00	439148	Suspended
B7I	105/01-21-077-05W4/00	445313	Suspended
B8I	115/08-21-077-05W4/00	445314	Suspended
D3N	116/07-21-077-05W4/00	449271	Suspended
AP2P	104/05-12-077-06W4/02	452921	Suspended
F3N	118/05-21-077-05W4/00	453085	Suspended
F4N	119/05-21-077-05W4/00	453086	Suspended
DE1I	104/06-12-077-05W4/02	490962	Suspended
DE2I	105/06-12-077-05W4/02	490963	Suspended
AQ11N	102/05-13-077-06W4/00	494103	Suspended

Table 5. List of Wells with Licence Status Changed to Abandoned

Well Ref Number	API/ UWI	Licence #	Licence Status
1-22-78-6	100/01-22-078-06W4/00	126046	Abandoned
9-21-78-6	100/09-21-078-06W4/00	165312	Abandoned
2-2-78-6	100/02-02-078-06W4/00	157038	Abandoned
9-16-78-6	100/09-16-078-06W4/00	165269	Abandoned
11-2-77-4	100/11-02-077-04W4/00	130805	Abandoned
10-27-77-6	100/10-27-077-06W4/00	279286	Abandoned
3-5-77-5	100/03-05-077-05W4/00	300053	Abandoned
12-5-77-4	100/12-05-077-04W4/00	326594	Abandoned
16-14-77-5	100/16-14-077-05W4/00	390884	Abandoned
14-14-77-5	100/14-14-077-05W4/00	431210	Abandoned
8-18-77-5	100/08-18-077-05W4/00	444412	Abandoned
8-17-77-5	113/08-17-077-05W4/00	461591	Abandoned
7-33-76-5	100/07-33-076-05W4/00	461618	Abandoned
12-19-77-5	103/12-19-077-05W4/00	461687	Abandoned
8-20-77-5	110/08-20-077-05W4/00	461688	Abandoned
3-30-77-5	100/03-30-077-05W4/00	462966	Abandoned
14-6-77-4	100/14-06-077-04W4/00	487031	Abandoned
3-1-77-5	100/03-01-077-05W4/02	119761	Abandoned
6-34-76-5	100/06-34-076-05W4/00	119763	Abandoned
11-21-77-5	100/11-21-077-05W4/02	138531	Abandoned
6-35-76-5	100/06-35-076-05W4/02	229821	Abandoned
11-33-76-4	1AC/11-33-076-04W4/00	443751	Abandoned

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 6 lists the regulatory approvals received for the CLRP over the reporting period.

Table 6. List of Regulatory Approvals Over the Reporting Period

Application Number	Description	Approval Date
1938573	Amendment application for modifications to the subsurface drainage patterns, MC North and MC South.	2022-07-07
1939182	Amendment application for the addition of a Gas Cap Injection Well on Well Pad MC.	2022-09-30

1938428	Amendment application for subsurface addition of pattern MD.	2022-10-18

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:

- Completed catalytic viscosity reduction pilot project. Pilot equipment disconnected from CPF.
- Installed produced water oil-in-water analyzers in Phase 2B.
- Installed produced water turbidity analyzer in Phase 2B.
- Completed Phase 2B turnaround.

Some opportunities to improve that were addressed at the CLRP over the reporting period include:

- Modified sampling conditioning in physical BTU analyzer to improve reliability.
- Phase 2 vapour recovery unit reliability improvement in the second half of the year.
- Optimization of mechanical vapour compressor and drum boiler expansion.
- Completion of Phase 2 water treatment plant building sump upgrades.

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.
- Continued optimization of the chemical treatment program.
- Design and implement a treated produced gas filtration system to improve fuel gas mixed drum performance and reliability.
- Continuous improvement of Phase 1 and 2 tank blanket and vapour recovery system.
- Completion of Phase 1 disposal pump building sump upgrades.
- Implementation of thermal expansion overpressure mitigation strategy.

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. 216466-01-05. For the 2022 calendar year, MEG has no unaddressed non-compliances.

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, voluntary self disclosures and corresponding efforts provided in Tables 7 through 11, respectively. All the information provided below has been previously communicated to the AER.

Table 7. Voluntary Self Disclosures Over the Reporting Period

Date	Licence/ 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
2022-02-02	Facility	Salt Water	F 37114	Pipeline	No pipeline licence	07-16-77-05W4M	Un-licensed pipeline. The pipeline was deemed as B31.3 facility piping in the past but a section of the pipeline that is CSA requires a pipeline licence.	MEG re-licensed the pipeline. New D56 licence is P63028 line no. 1.

Table 8. 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
31576906	2022-02-13	13	6	550	Emergency	Phase 2 OTSG tripped resulting in produced gas being directed to flare.
31589785	2022-02-23	34	9	600	Emergency	Plant emergency shutdown caused by a faulty wire.
31589788	2022-02-23	8	9	350	Emergency	Venting - Phase 2HP flare went out resulting in gas venting intermittently until flare was operational.
31701478	2022-03-30	2	6	0	Emergency	Excessive purge gas directed to the flare header.
31763327	2022-05-14	284	326	700	Emergency	Due to a failure of the 2nd stage compressor on the Phase 2 VRU, operations sent gas from tank farm vapor header to the LP flare beyond the 4-hr limit.
31779874	2022-05-14	10	38	450	Emergency	Venting - Reported as intermittent tank pressure relieving device venting that exceeded 4 hours.
31783134	2022-06-02	757	892	500	Planned Maintenance	Intermittent flaring occurred during ramp up from MEG's Phase 2B Turnaround activities.
31796186	2022-06-06	343	162	500	Planned Maintenance	There was sudden breaker failure on the initial startup event which shut down power and production to the facility.
31802178	2022-06-17	203	16	500	Emergency	Boiler feedwater pump shut down resulted 2B OTSGs, 2B GTG/HRSG, and drum boiler/evaporator trips.
31817609	2022-07-04	34	9	450	Emergency	P2B HP flaring due to P2B steam plant (steam generators and GTG) tripping.
31829991	2022-07-12	15	5	400	Emergency	Flaring due to Ph2B OTSG and produced gas recycle compressor trip.
31838853	2022-07-20	44	12	345	Emergency	Phase 2B OTSG-A trip which was followed by a planned Phase 2B GT/HRSG outage.
31841029	2022-07-23	9	5	345	Emergency	Flaring due to excess gas production from the field. Field was eventually cut back (wells shut down) to close the flare valve ending the flaring event.

Table 8. Reportable Flaring and Venting Events Over the Reporting Period (Cont.)

AER ID	Date	Est. Volume (e^3m^3)	Est. Duration (hrs)	H_2S Conc (ppm)	Reason	Details
31993340	2022-11-10	12	43	700	Unplanned Maintenance	Unplanned maintenance due to carryover of fluid into PH2 VRU header.
32056188	2022-11-10	59	88	700	Unplanned Maintenance	Venting associated with previously reported Phase 1 flaring (AER Notification 31993340).
32002408	2022-11-20	0.1	4	500	Unplanned Maintenance	High temperature on the Phase 1 Produced Gas Separator tripped the valve to the fuel gas mix drum.
32012292	2022-11-22	169	88	1600	Emergency	Leak in the PH2 VRU discharge header that required the VRU be shut down and the header to be safely isolated to allow for repairs.
32030755	2022-11-22	31	88	700	Unplanned Maintenance	Venting - associated with previously reported Phase 1 and 2 flaring (AER Notification 32012292) that resulted in a VRU outage.
320024953	2022-12-01	50	65	2800	Planned Maintenance	Planned maintenance on the Phase 2 Vapor Recovery Unit (VRU) to perform required upgrades and general maintenance.

Table 9. Reportable Spills Over the Reporting Period

AER ID	Date	Location	Fluid	Est. Volume (m^3)	Est. Duration (hrs)	Facility/ Pipeline	Details	Corrective Action
20220238	2022-01-20	13-04-077-05-W4	Produced Water	0.002	N/A	Pipeline	During the annual pipeline inspection, a dark icicle was observed on the bottom of Pad G above ground emulsion pipeline lateral (Pipeline License No. 46442, Segment #12). Additional inspection identified a small crack/pinhole leak. Pipeline was depressurized and internal review/investigation initiated.	Cause was related to intergranular stress corrosion cracking (IGSCC) with additional detail provided to the AER in the Pipeline Incident Review Letter submitted March 11, 2022.
20220332	2022-02-02	10-29-077-05W4	Produced Water	59	0.75	Pipeline	Incident was related to a corrosion probe failure that was installed on the on-lease pipeline header associated with pipeline license #60589-3. Release occurred on frozen ground and all fluids were recovered.	Ensuring correct installation detail are on the equipment data sheet for installer.
20220845	2022-04-11	02-16-077-05W4	Process Water	5.54	N/A	Facility	The neutralization pump had an internal pump seal leak, resulting in release of fluids through a tattletale drain located at the bottom of the pump casing onto the floor of the building.	MEG purchased a specialty tool that will ensure the integrity of the seals when the pumps are overhauled.

Table 10. Contraventions Over the Reporting Period

AER ID	Type	Date	Location	Details	Corrective Action
388352	Late Report	2022-03-02	02-16-077-05W4	The January electronic CEMS data file was not submitted to the Alberta Environment & Parks website by the February 28, 2022 reporting deadline.	MEG has implemented an automated notification/reminder process for the monthly CEM industry sign-off submission.
401142	90% Monthly Availability limit not achieved – (Cylinder Gas Audit (CGA) test failure)	2022-07-20	02-16-077-05W4	The 90% CEMS monthly availability was not achieved on the Phase 2B OTSG stack GM32 NOx analyzer for the month of July due to a failed CGA test on July 20/2022.	MEG will continue to follow the CEMS Quality Assurance plan including completing the prescribed maintenance PM's on the analyzers and conducting internal gas checks with certified gas in advance of all stack tests.
404028	MEG contravened Section 4.2 of Water Act Approval 00320633-00-01	2022-09-07	07-32-076-05W4	Water was withdrawn from 7-32 WSW2 for dust control purposes without valid weekly water level recordings for that week.	Standard Operating Procedure developed to ensure accountable MEG personnel have the required software uploaded onto a laptop so that operability of the transducers can be confirmed prior to the water withdraws.
408316	Missed sample/Incomplete Report	2022-11-30	02-16-077-05W4	On January 3, 2023, the contract operating company for the WWTP was performing monthly reporting tasks and discovered that the required monthly grab samples for pH, Electrical conductivity, and sodium adsorption ratio (SAR) were not analyzed for the month November.	WWTP operators will start cross referencing the samples halfway through the month with third party laboratory job confirmation emails.
407581	90% Monthly Availability limit not achieved – (CGA Test Failure)	2022-12-07	02-16-077-05W4	90% CEMS monthly availability was not achieved on the Phase 2B OTSG stack GM32 NOx analyzer for July due to failed CGA test on December 7, 2022.	MEG requested that the analyzer vendor come to site to correct the analyzer drift that are contributing to the recent CGA failures.

Table 11. 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. • VRU repairs were given immediate priority when required.
Spills	• Ongoing spill mitigation and communication protocols in place. Focused spill campaigns in place for 2022 based on spill data trends to target highest risk/occurrence spills. Spills are categorized as equipment related or human factor to help target improvement initiatives. • All spills are immediately cleaned up. • Incident investigation meeting to assign investigator, identify root cause and implement corrective actions and mitigations.
Voluntary Self Disclosure	• When required corrective actions or mitigations are identified and implemented.
Contraventions	• When required, corrective actions or mitigations are identified and implemented. • 2022 specific corrective actions identified in Table 10.

4.12 Future Plans

MEG is continuously assessing optimization options aimed at enhancing overall performance. Over the next reporting period, the previously approved sulphur removal unit (SRU) expansion is expected to be in operation. The steam distribution systems will be re-rated from 8 MPa to 10 MPa to allow injection of steam in development areas that are further way from the CPF. This modification includes a new high pressure steam separator in the Phase 2 area of the CPF.

Also, in the CPF, produced water and filtered water heat recovery exchangers, as well as produced water and glycol heat exchangers,0 will be installed in the Phase 2B area to allow for higher produced water throughput. Additional Phase 2 and Phase 2B glycol aerial coolers will also be installed to assist in cooling demand associated with higher throughput during the summer months.

Lastly, a new casing gas pipeline, paralleling existing infrastructure, will be put into service in the second half of the year to reduce backpressure between well pads and the CPF.

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

FIGURES

Figure 1 **Annotated Scheme-Level Lifespan Production Plot**

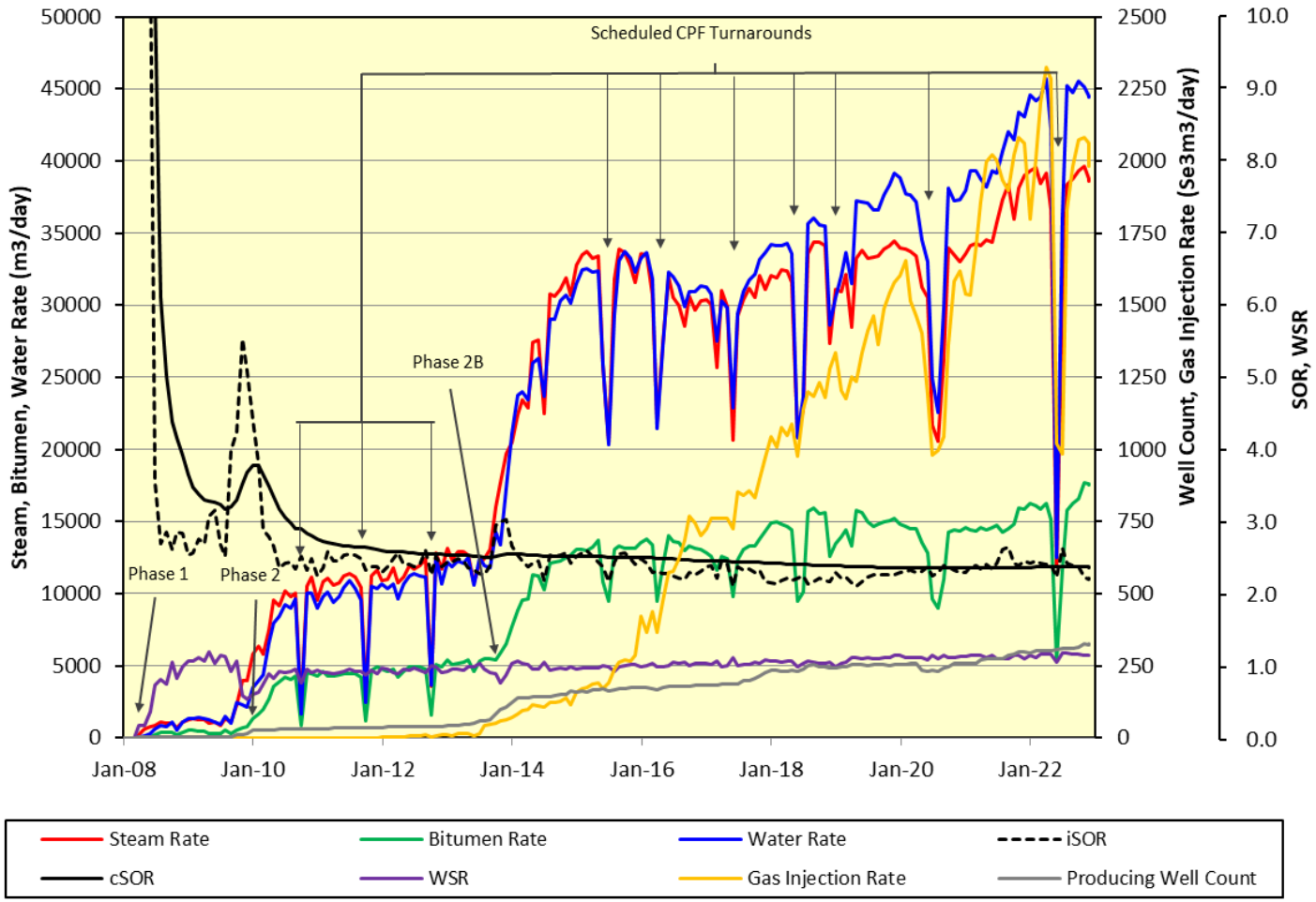
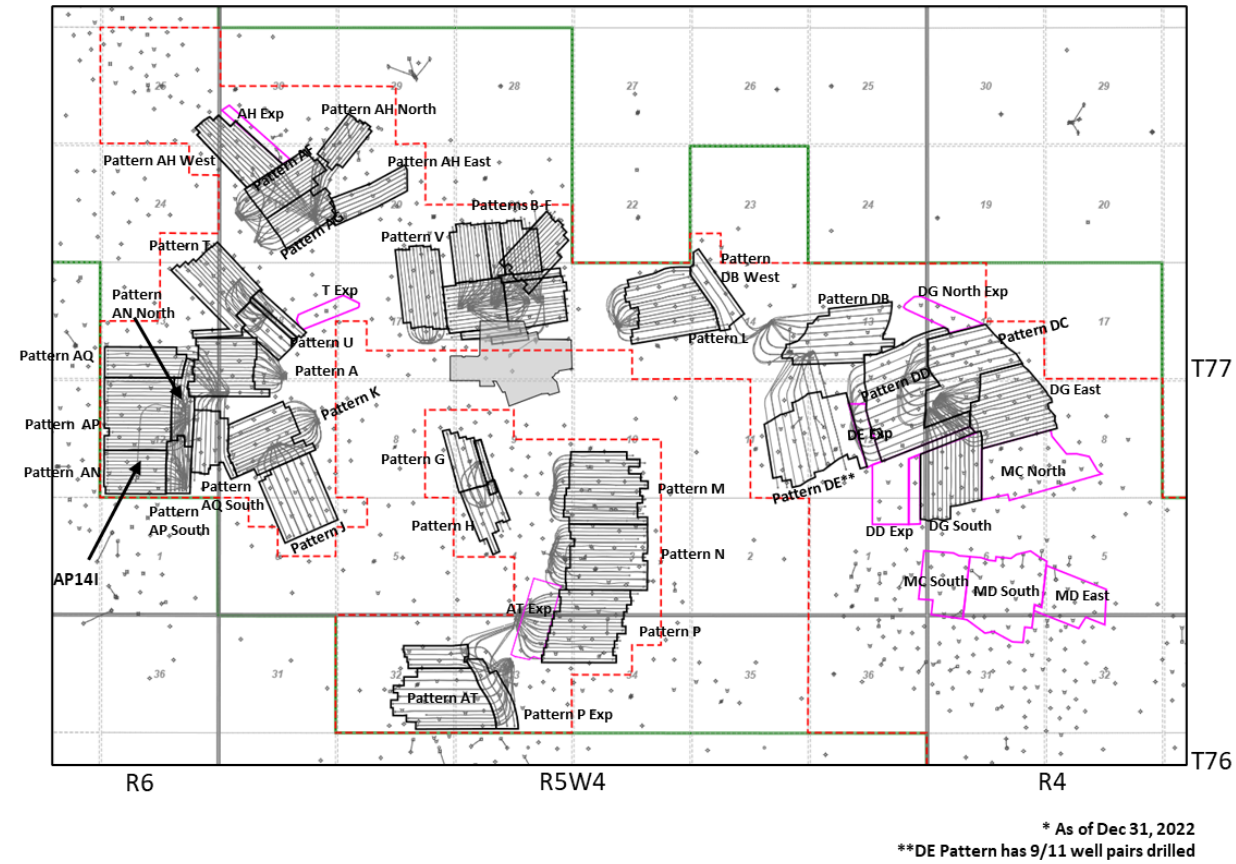


Figure 2 **Drilled and Approved Drainage Patterns**



* As of Dec 31, 2022
**DE Pattern has 9/11 well pairs drilled

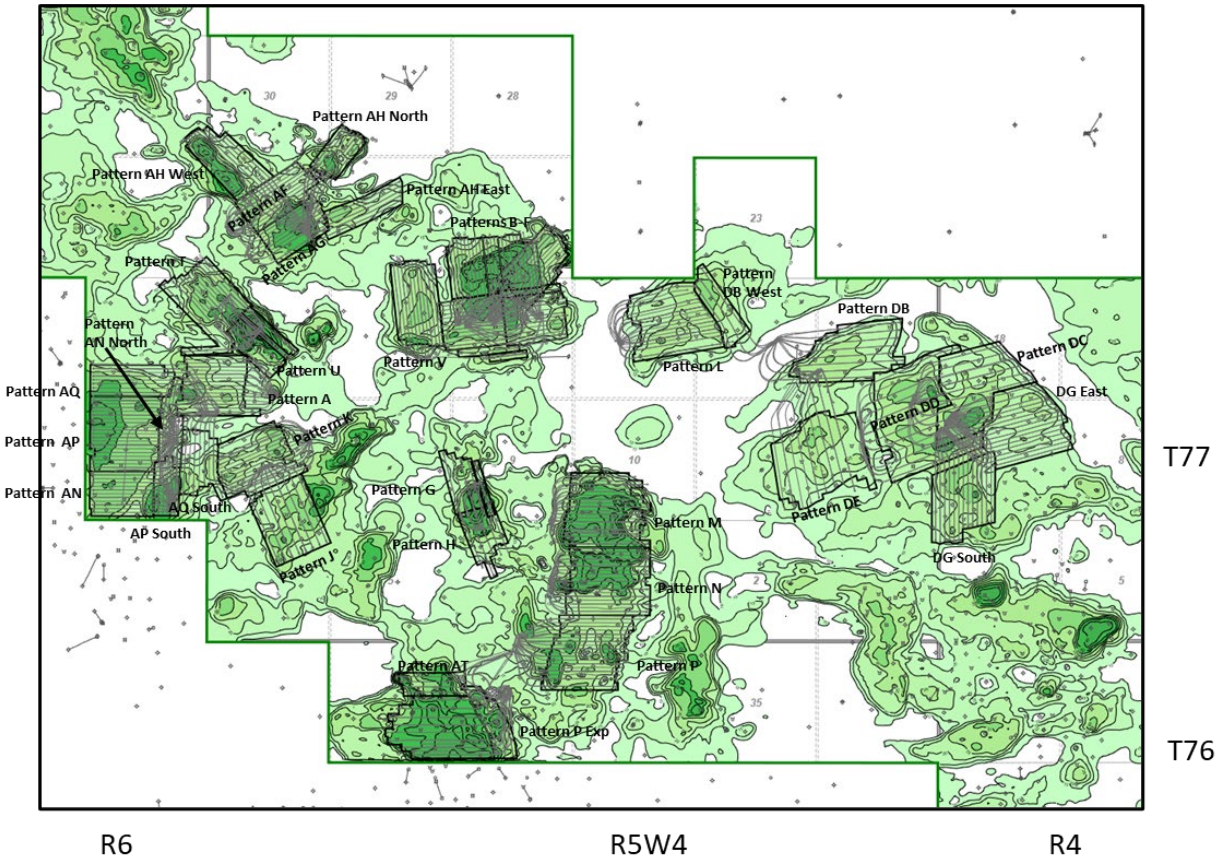
MEG OSL

Approved Development Area

Approved Patterns

Central Plant

Figure 3 **Net Pay Isopach**



SAGD Pay Cutoffs:

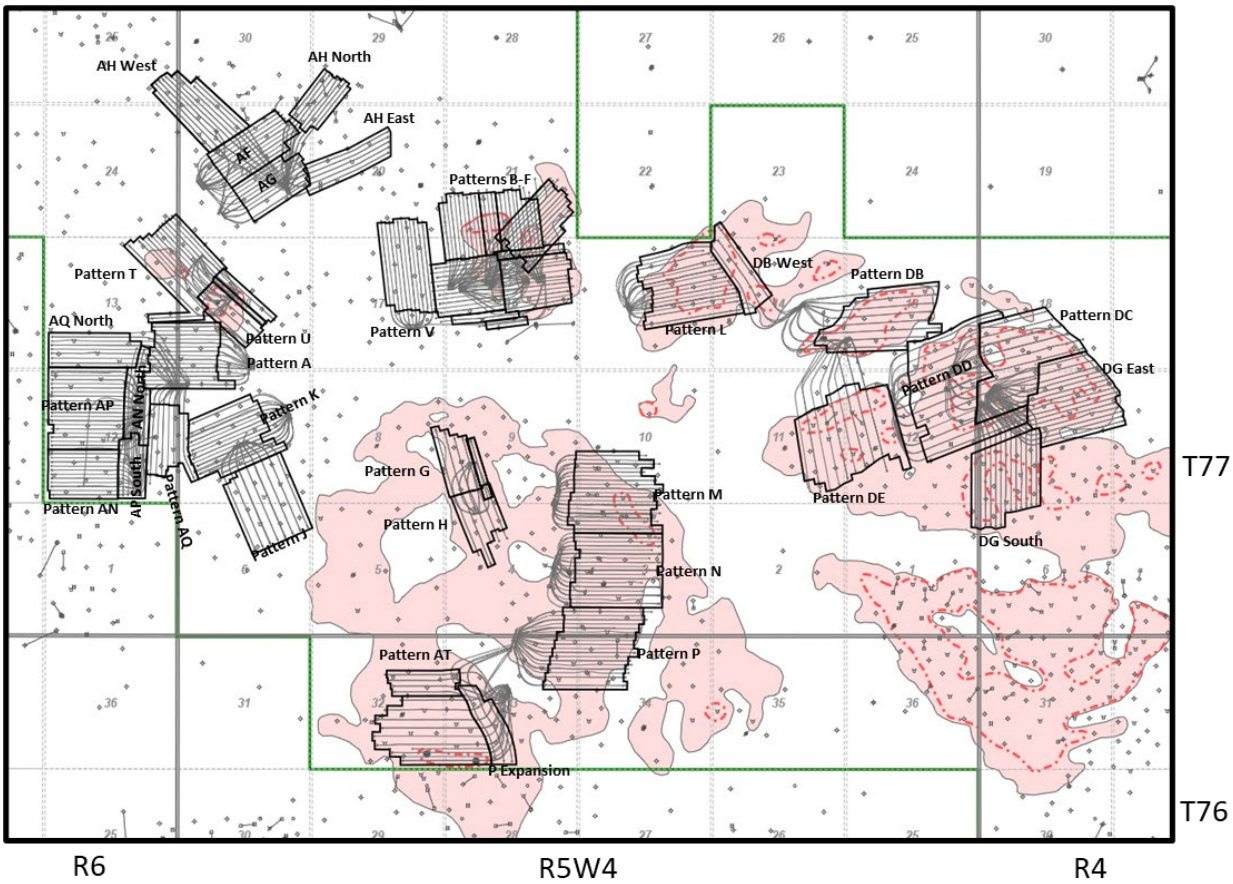
- Continuous bitumen pay ≥ 10 m (defined by logs, images and core)
- So ≥ 50% (~6 wt% bulk mass oil);
- Porosity (density) ≥ 25%;

Min contour = 10 m
Contour interval = 5 m

CLRP Project Area

SAGD Patterns

Figure 4 Associated Gas in Communication with Pay



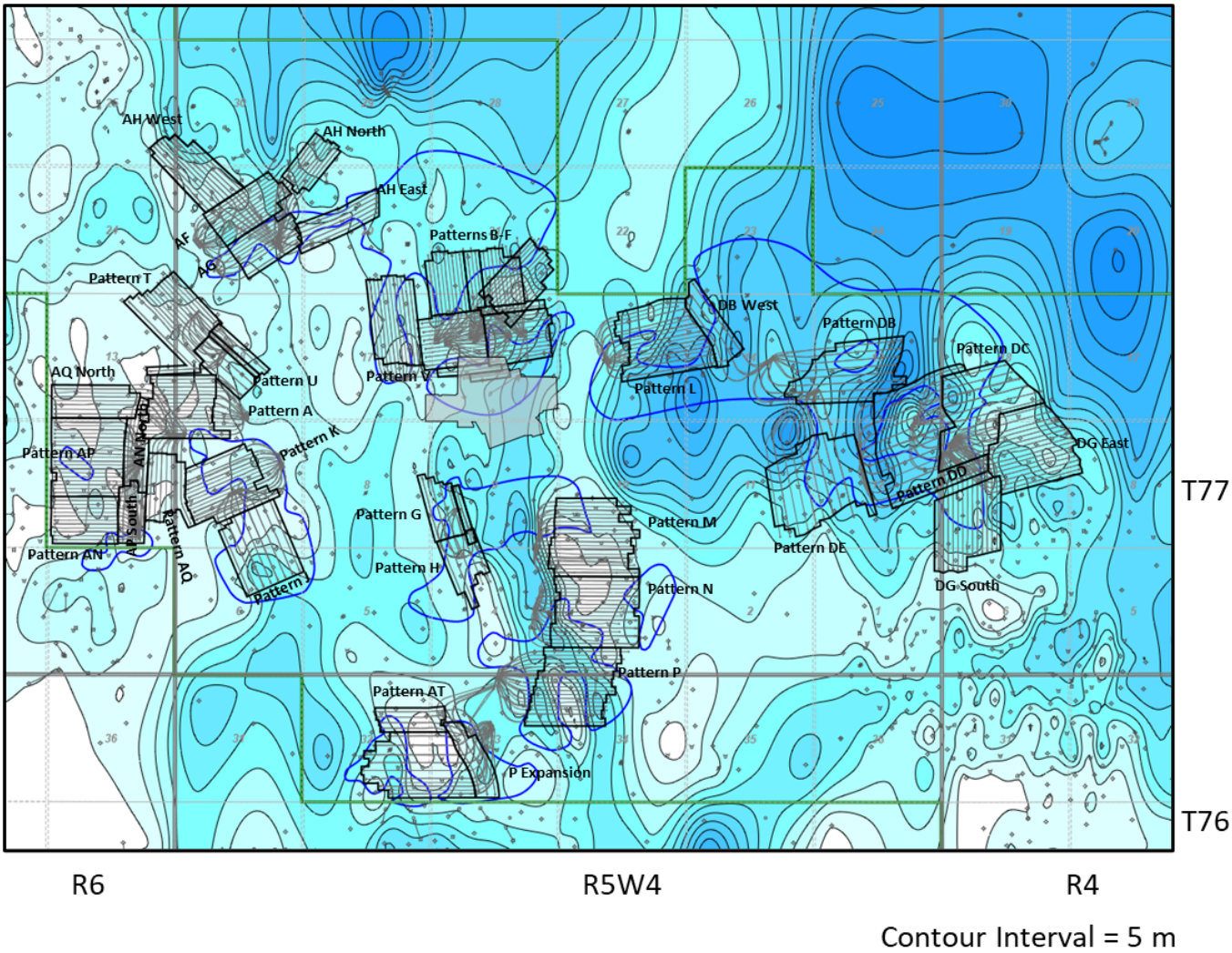
MEG OSL

Drilled SAGD Patterns

Gas Pool in direct or indirect contact with SAGD interval

Direct contact between top of reservoir and Gas interval

Figure 5 **Net Basal Water Isopach**



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**

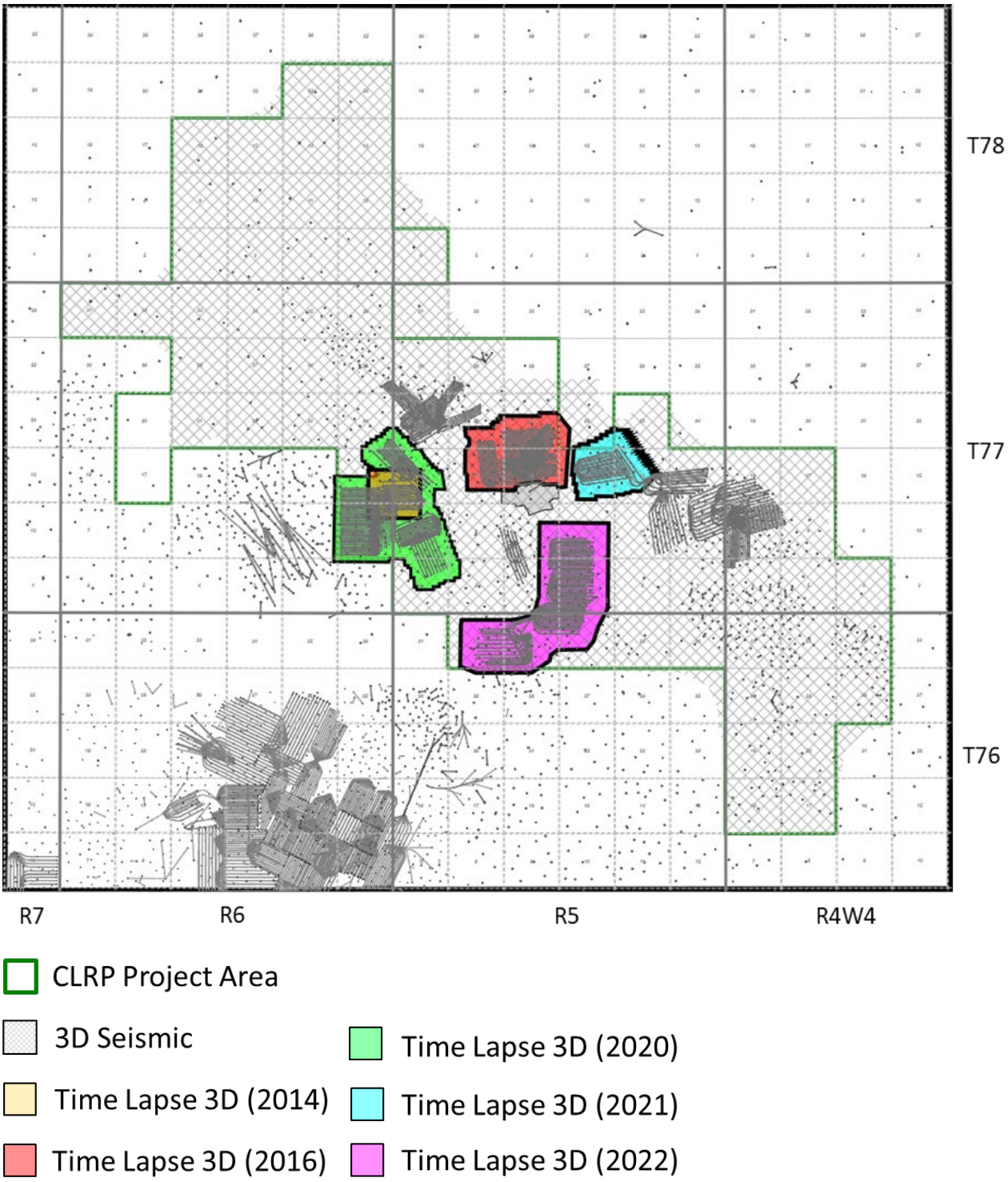


Figure 7 **Representative Cross Section within the Active Development Area**

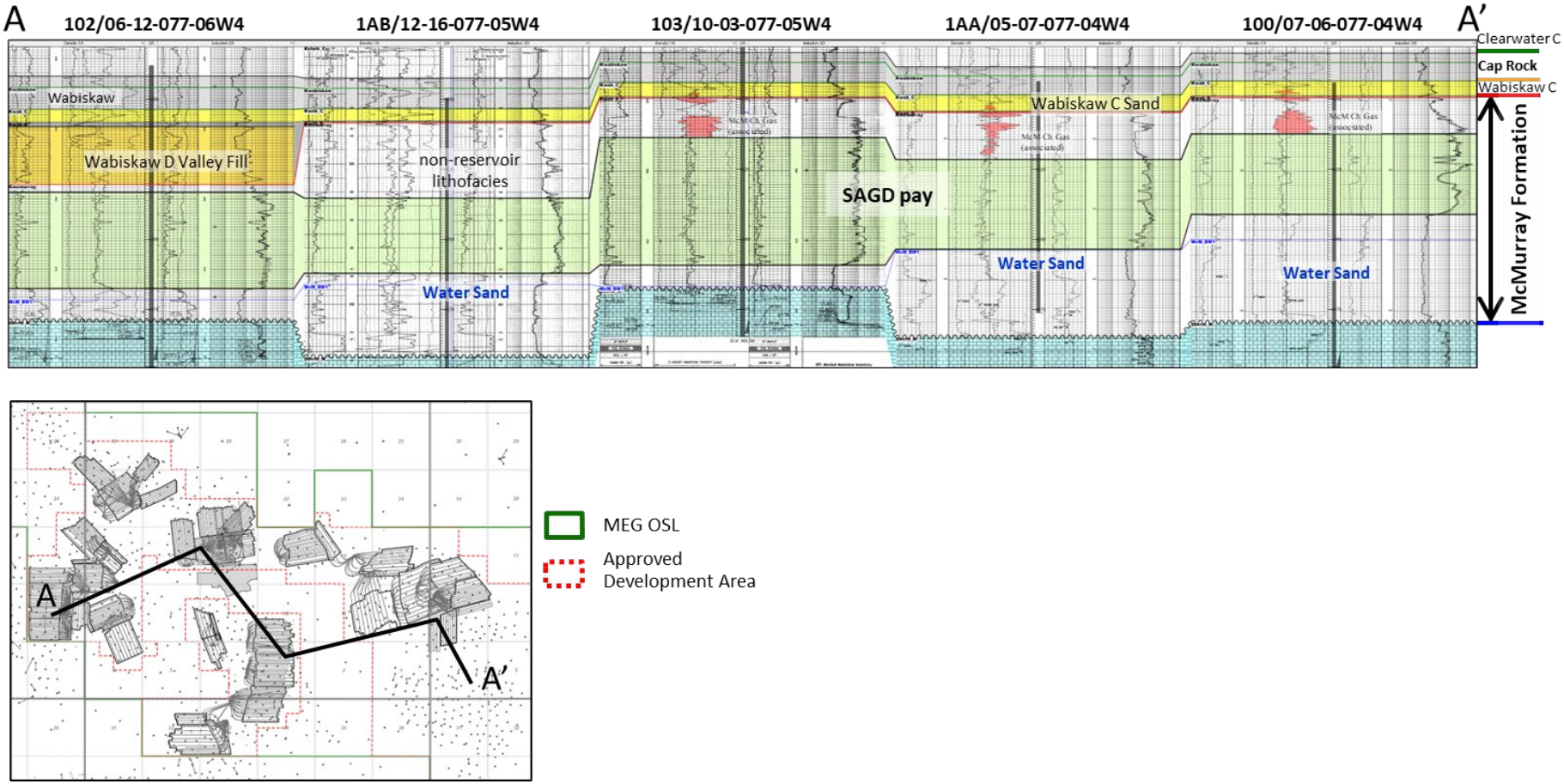


Figure 8 **Injection Wells by Type as of December 31, 2022**

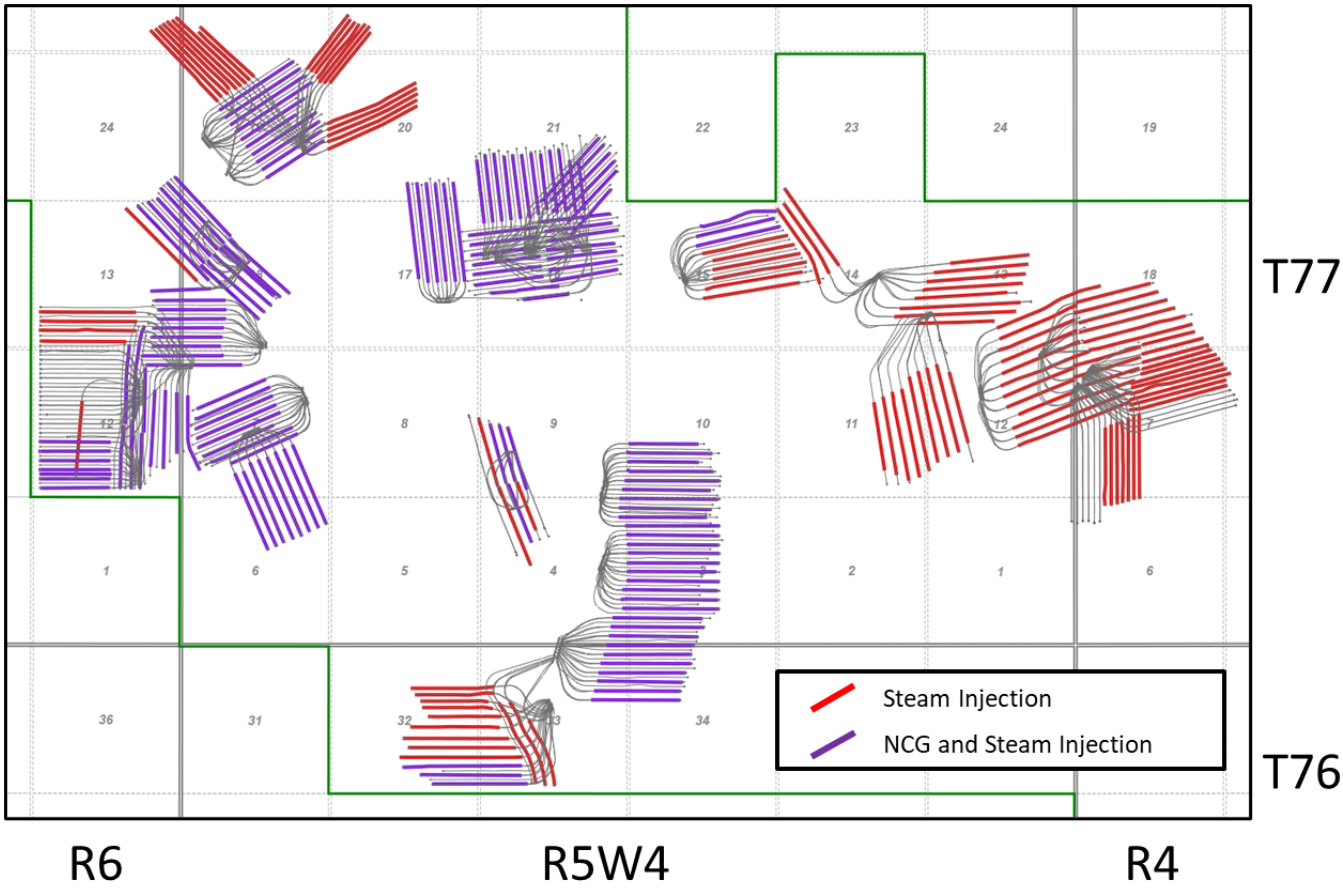


Figure 9 **iSOR, NCG Injection Concentration, and cSOR Performance for Phase 1, Phase 2, and Phase 2B Well Patterns**

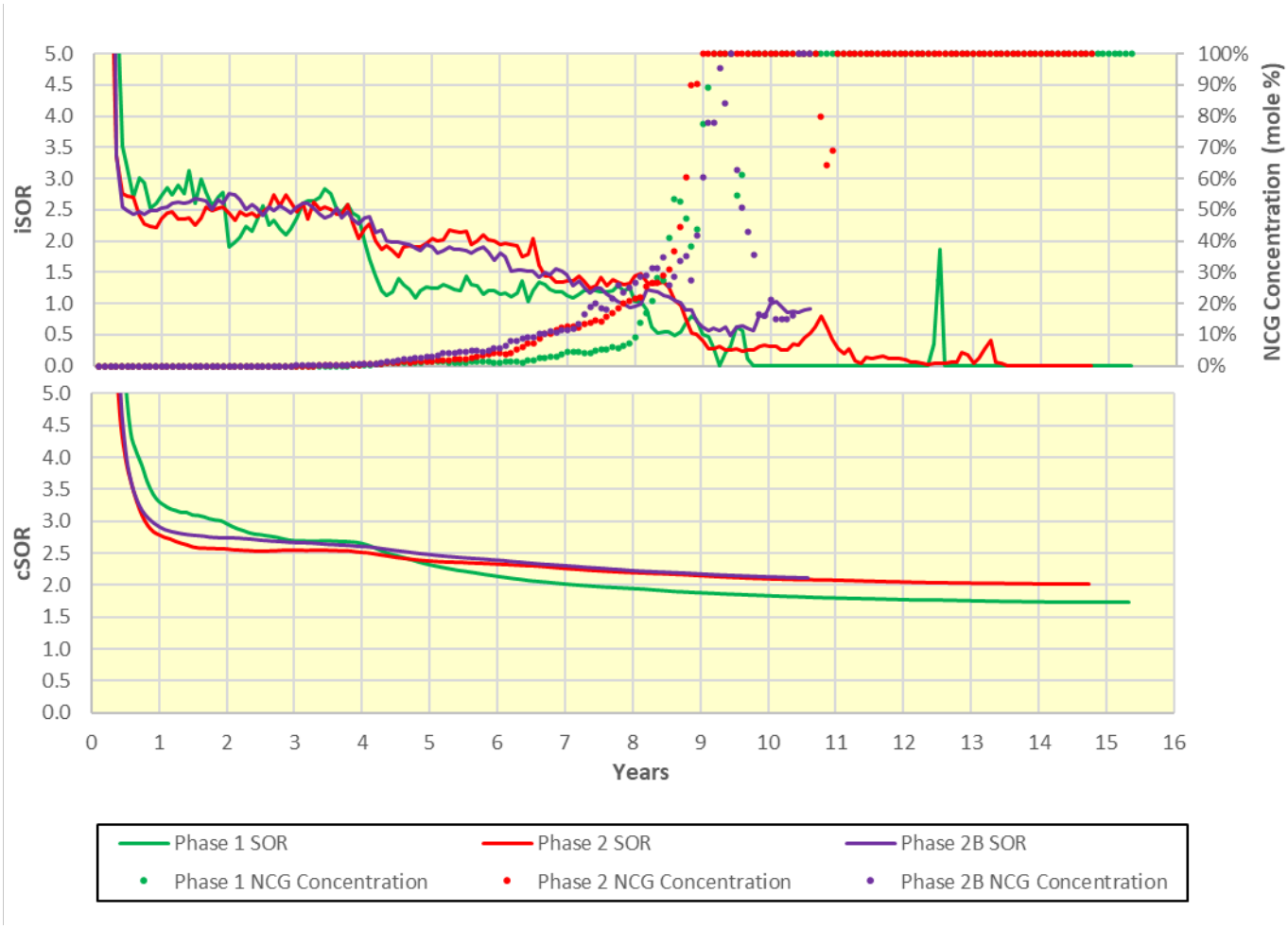


Figure 10 Constructed and Planned Surface Infrastructure within the Development Area

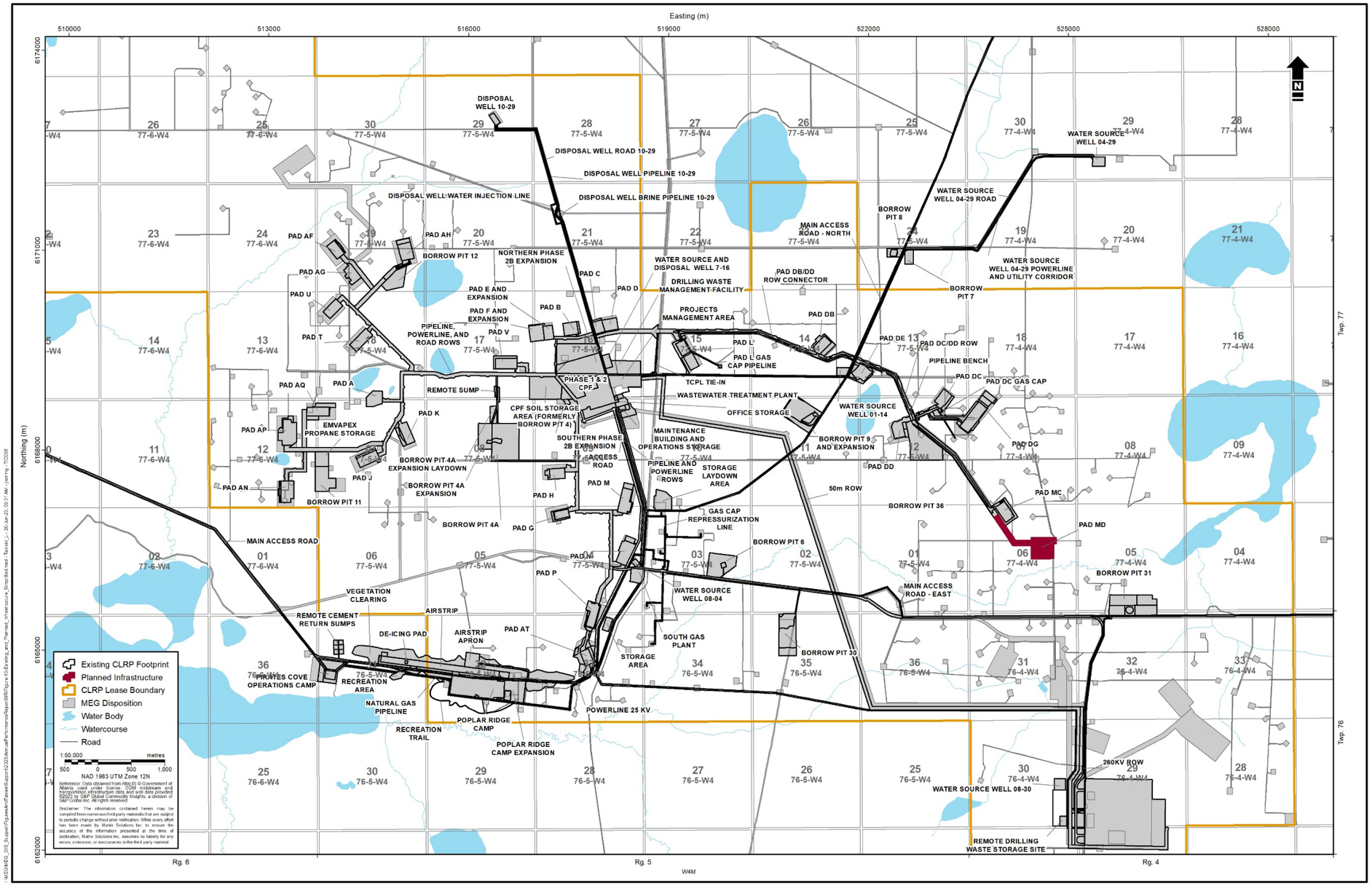


Figure 11 Source and Disposal Wells within the Development Area

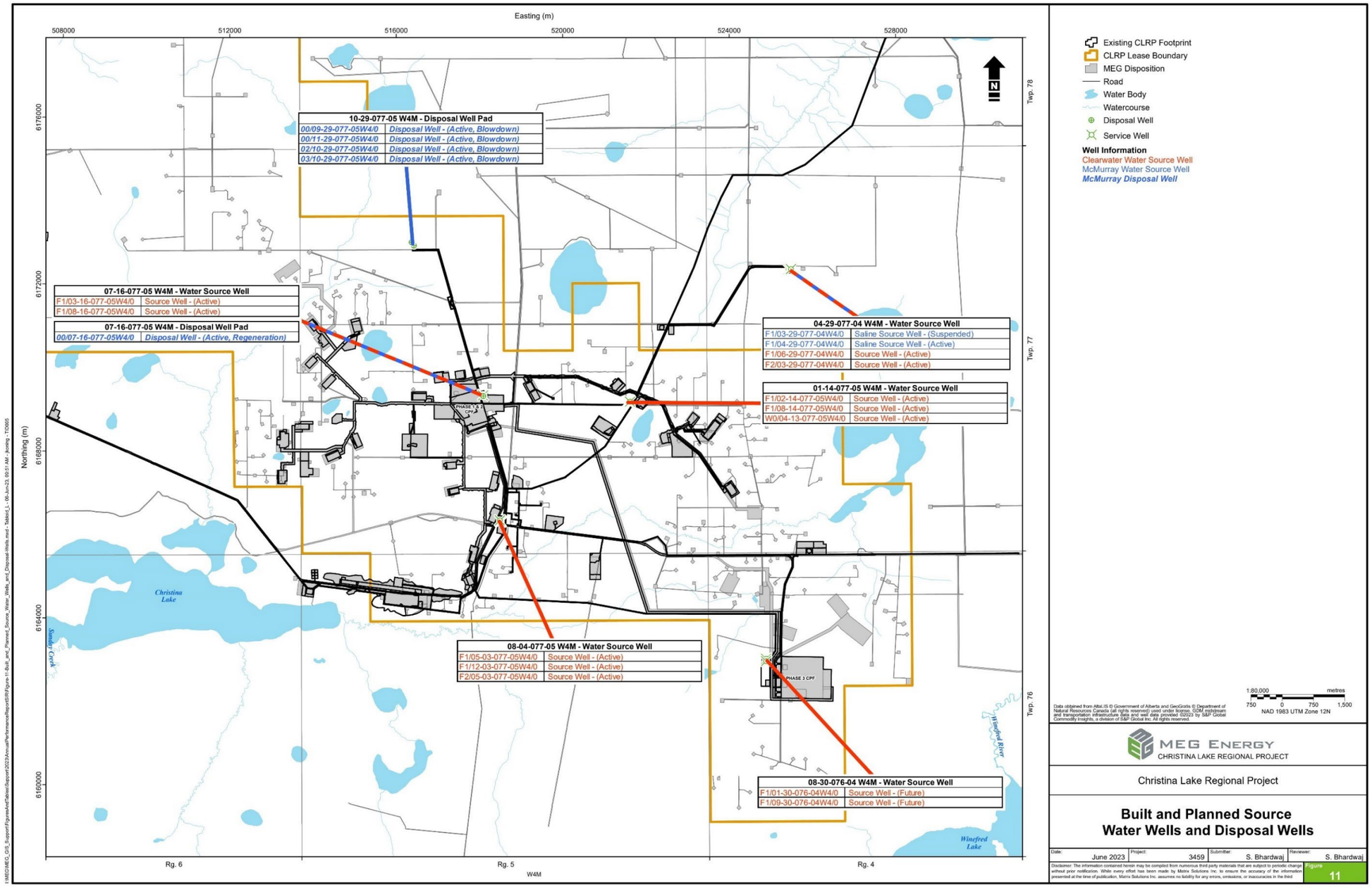


Figure 12 **Facility Performance: Actual vs. Design Bitumen Treatment Throughputs**

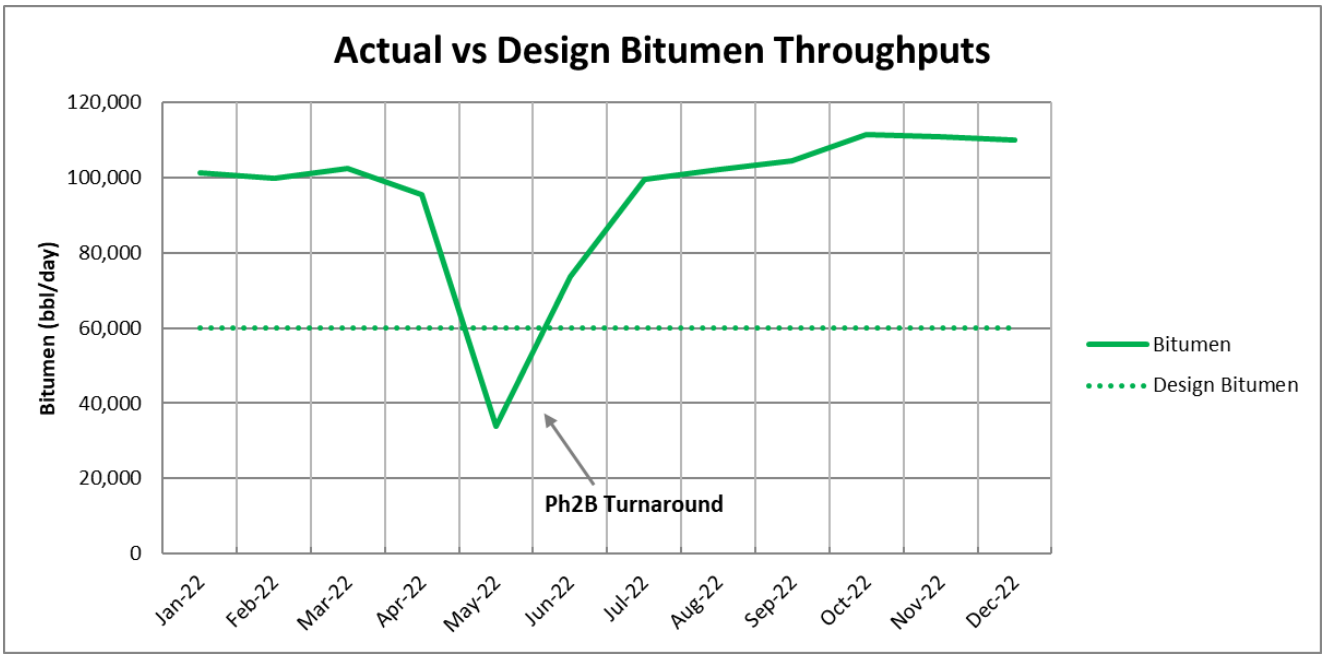


Figure 13 **Facility Performance: Actual vs. Design Steam Generation Throughputs**

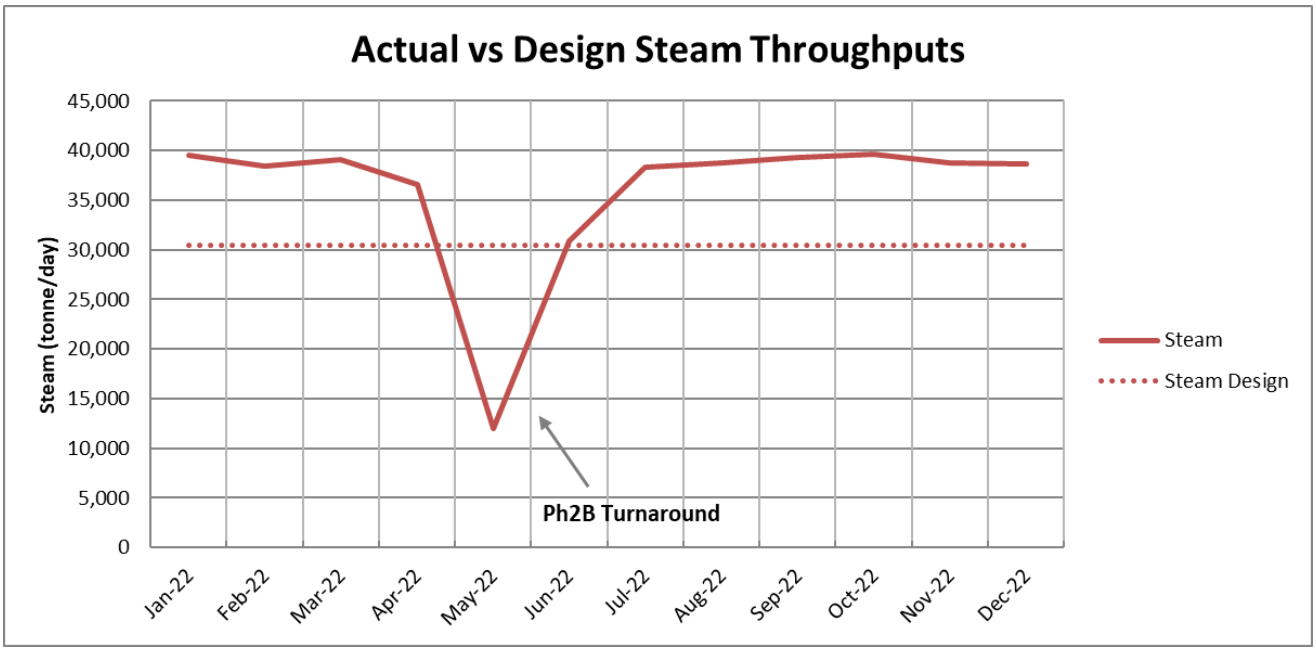


Figure 14 Future Planned Development Areas