HANGINGSTONE SAGD PROJECT

AER *DIRECTIVE 054* PERFORMANCE REPORT

SCHEME APPROVAL NO. 8788, AS AMENDED

EPEA APPROVAL NO. 1604, AS AMENDED

JUNE 2021

DISCLAIMER

*Some of the statements contained in the presentation are "forward-looking statements" within the meaning of applicable Canadian securities laws. All statements in this presentation, other than statements of historical facts, that address estimated future performance, events or circumstances are forward-looking statements and are based upon internal assumptions, plans, intentions, expectations and beliefs. Although Greenfire Acquisition Corporation ("**Greenfire**" or the "**Corporation**") believes the expectations expressed in such forward-looking statements are based on reasonable assumptions, such statements involve risks and uncertainties and should not be in any way construed as guarantees of future performance.*

Actual results or developments may differ materially from those in the forward-looking statements. Factors that could cause actual results to differ materially from those in the forward-looking statements include operational risks in exploration, development, exploitation and production, delays or changes in plans with respect to development or capital expenditures, uncertainty of estimates and projections, including costs and expenses, commodity price and exchange rate fluctuations, environmental risks, competition for scarce resources, recovery rates, regulatory approvals, interest rate changes, and the lack of availability of necessary capital (i.e. capital which may not be available to Greenfire on terms acceptable to Greenfire or at all). Greenfire is subject to the specific risks inherent in the oil and gas business as well as general economic and business conditions.

Greenfire cautions the reader not to place undue reliance on its forward-looking statements, which speak only as of the date of this presentation.

TABLE OF CONTENTS

GREENFIRE
ACQUISITION CORP.

SECTION 1.0 – BACKGROUND

HANGINGSTONE SAGD PROJECT

Scheme Approval No. 8788, as amended

EPEA Approval No. 1604, as amended

June 2021

1.1 BACKGROUND

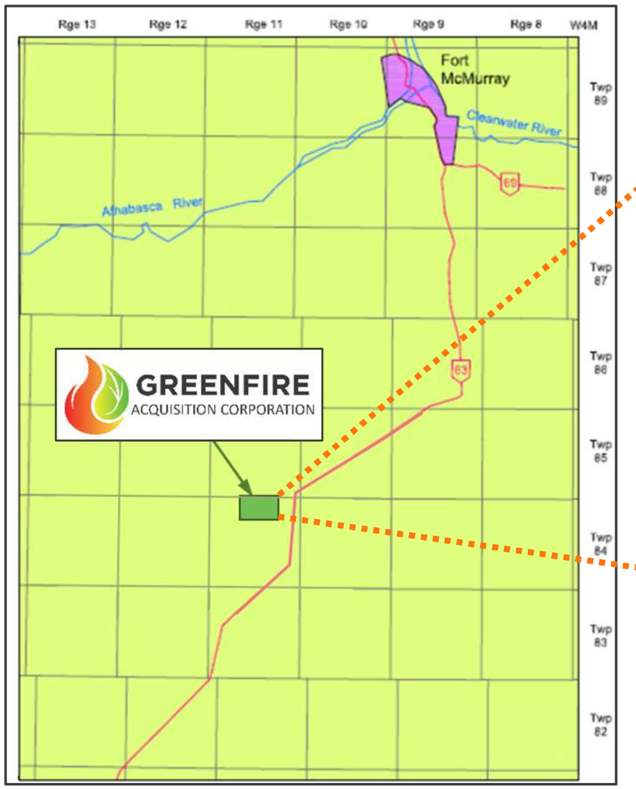
- Hangingstone Project (the "**Project**") has been in operation since 1999, with and approved production capacity of 1,760 m^3/day
- Alberta Energy Regulator ("**AER**") Approvals:
  - EPEA Approval No. 1604-03-01
  - Scheme Approval No. 8788Q
- Project Operational History
  - Operated from 1999 to May 2016
  - Suspension from May 2016 to September 2018
  - Operated from September 2018 to April 2020
  - Suspension from May 2020 to December 2020
  - Recommission and re-start activities commenced December 2020

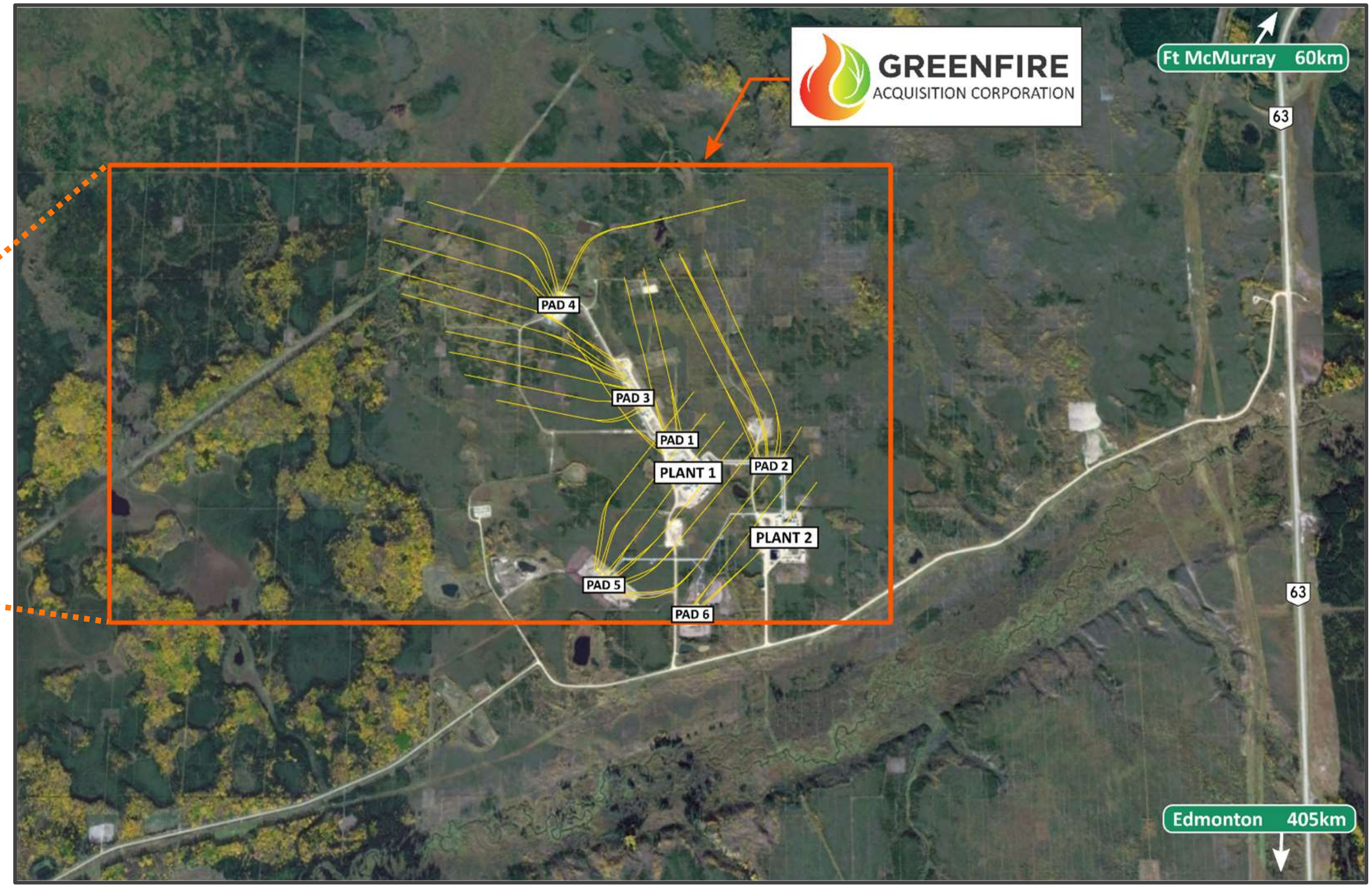
NOTE:

- *On March 17, 2021, the AER transferred the Project from the previous operator to the Greenfire Acquisition Corporation.*
- *The subject report includes information from September 2019 to December 2020. This period covers from the end of the last Directive 054 report to the end of the 2020 calendar year and is noted as the "reporting period" throughout.*

1.2 LOCATION

- The Project is located approximately 60km south of Fort McMurray, Alberta





SECTION 2.0 – SUBSURFACE

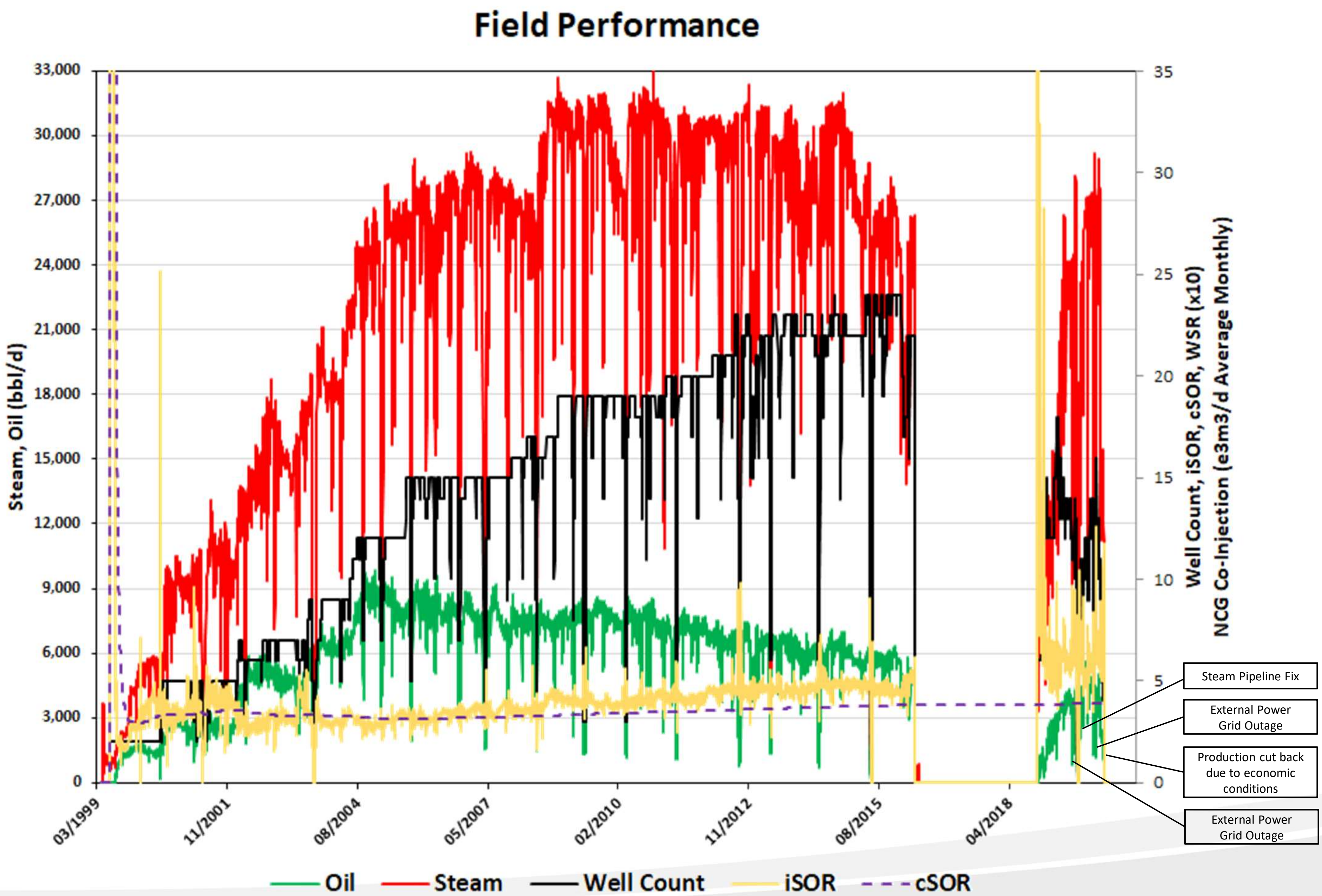
HANGINGSTONE SAGD PROJECT

Scheme Approval No. 8788, as amended

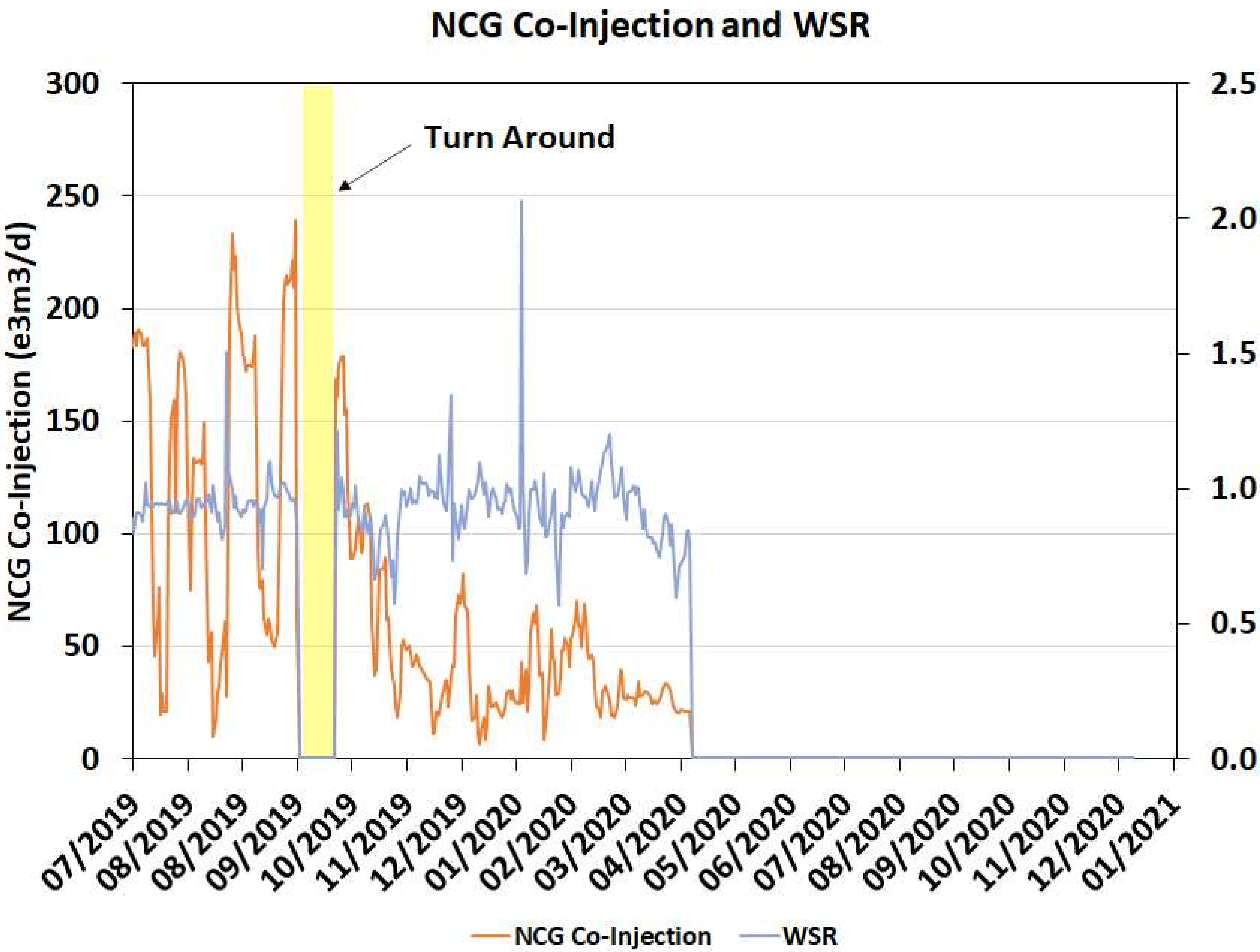
EPEA Approval No. 1604, as amended

September 2019

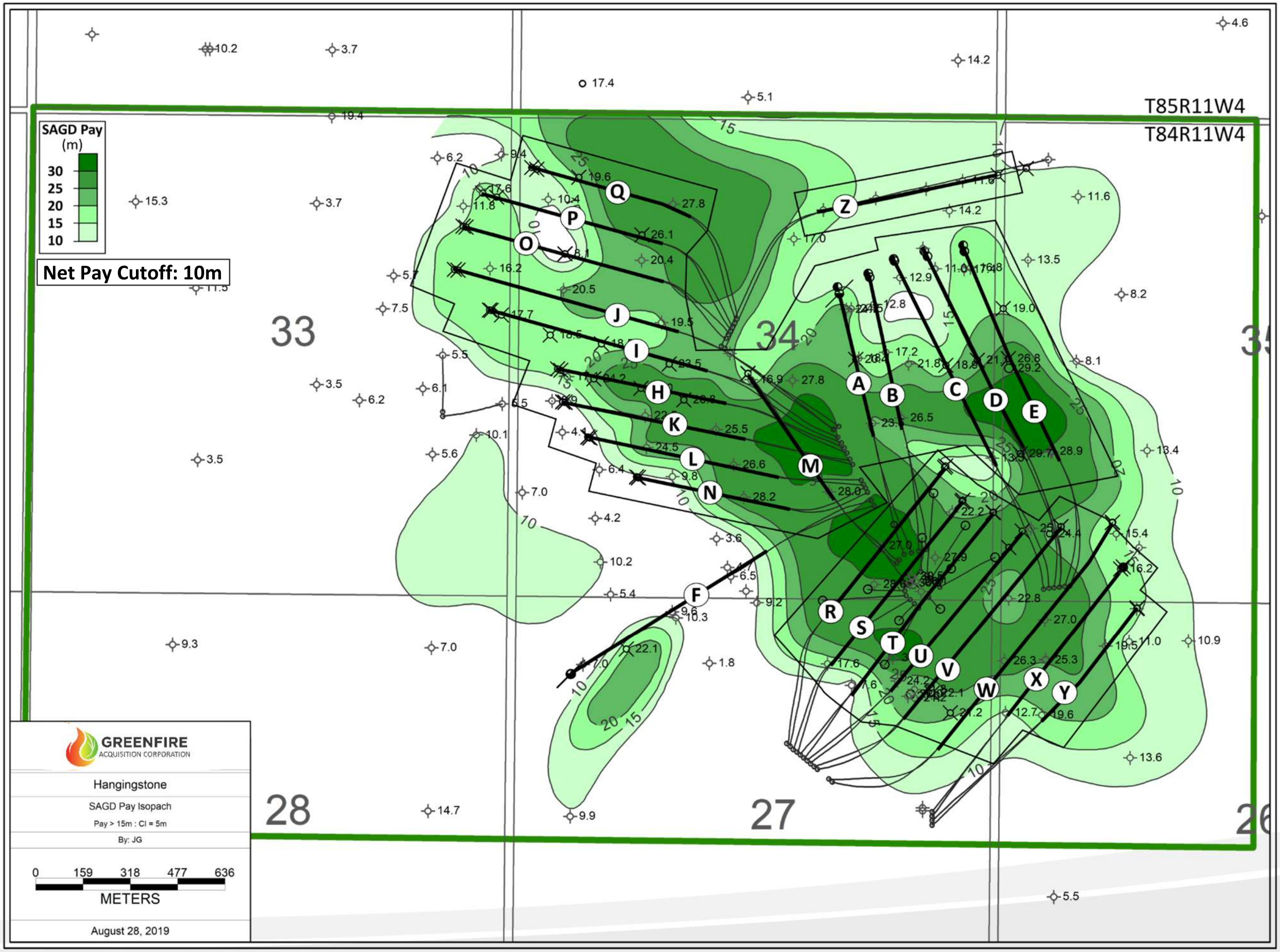
2.1 LIFESPAN PRODUCTION



2020 FIELD NCG CO-INJECTION, WSR



2.2 GEOSCIENCE - NET PAY ISOPACH AND DRAINAGE AREAS



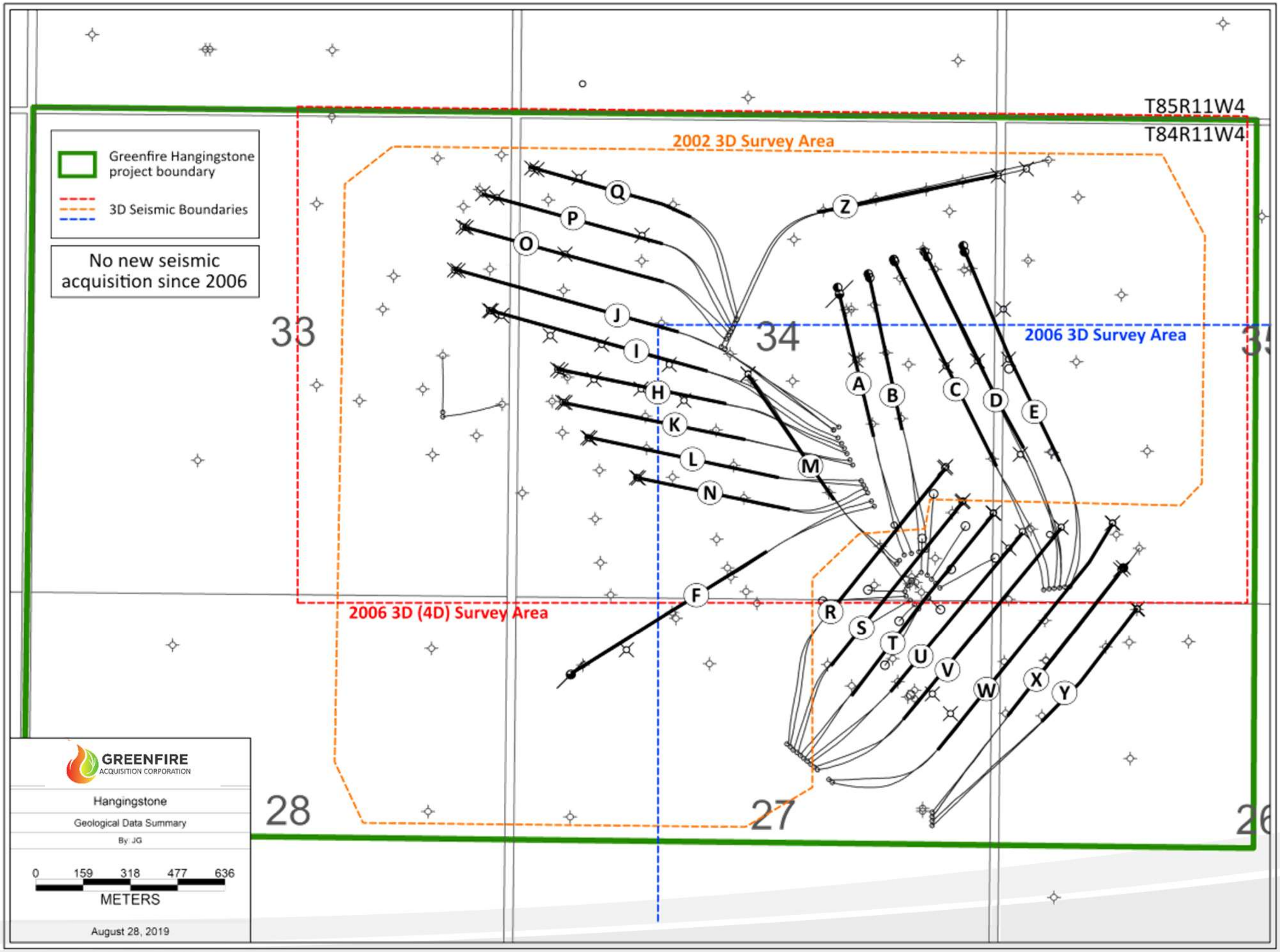
2.3 GEOMECHANICAL ANOMALIES

- No change in caprock integrity analysis since August 2018
- Original injection pressures determined by mini-frac tests in the 1980's
- JACOS Hangingstone Expansion (~3km from Greenfire's Project) conducted mini-frac testing in 2010 and exhibited consistent results to original data
- 5 MPa determined to be maximum wellhead injection pressure (80% of fracture pressure)
- Reservoir pressure is monitored through blanket gas pressure readings in the casing annulus

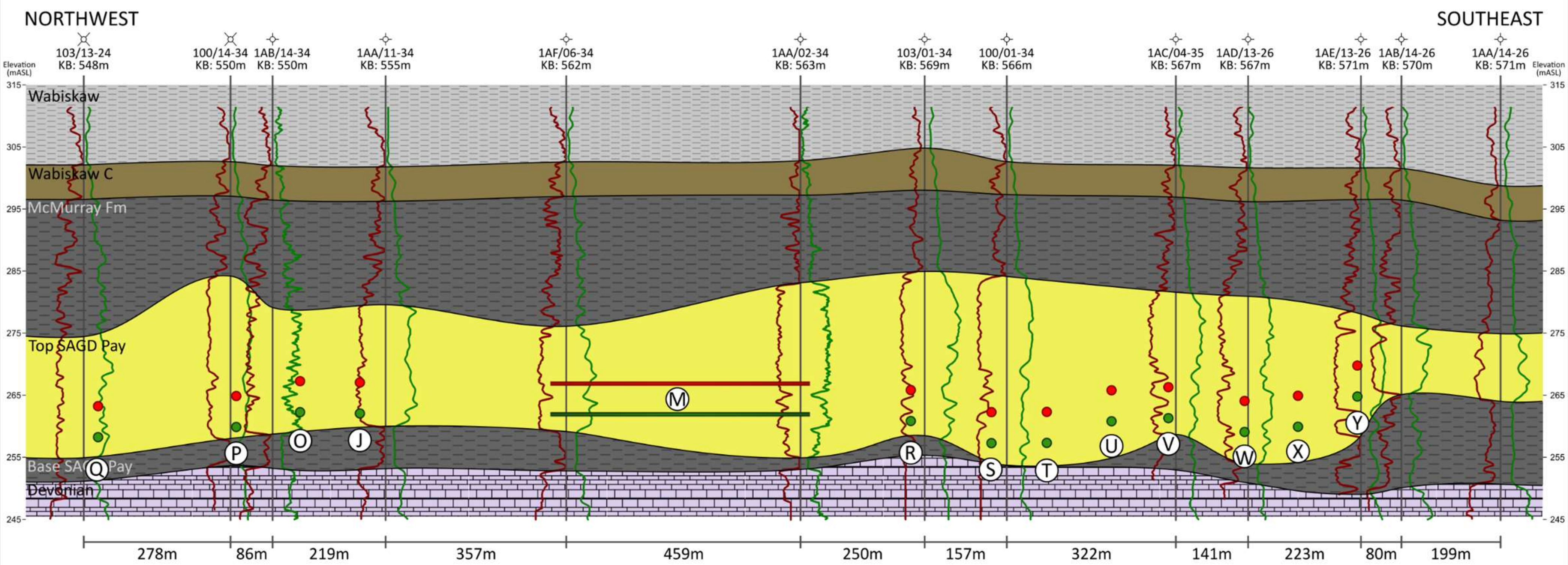
	Depth	Min. Stress		Vertical Stress		Stress Regime
Formation/Lithology	TVD (m)	Mpa	kPa/m	Mpa	kPa/m	
Clearwater Shale	272.0	5.39	19.82	5.73	21.07	Horizontal Fracture (?)
Wabiskaw Shale	297.0	6.17	20.77	6.26	21.08	Horizontal Fracture
McMurray Shale	314.5	5.55	17.65	6.64	21.11	Vertical Fracture
McMurray Sand	327.0	5.59	17.09	6.91	21.13	Vertical Fracture

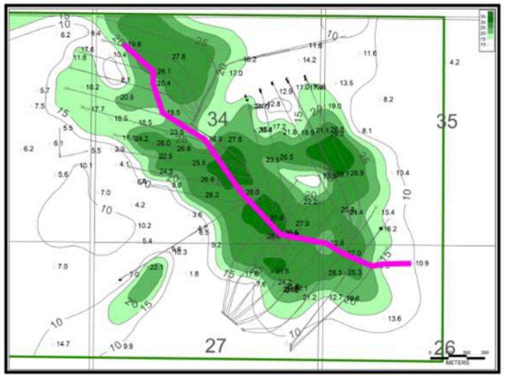
From JACOS Hangingstone Expansion 2018 AER Performance Review

2.4 GEOSCIENCE - GEOLOGICAL DATA SUMMARY



2.5 WELL CROSS-SECTION





Hangingstone is a Tier 1 Reservoir:

- No top gas
- No top water
- No lean/transition zones
- No bottom water

GREENFIRE ACQUISITION CORPORATION

Hangingstone Cross Section

100m
500m

2.6 ORIGINAL BITUMEN IN PLACE

Reservoir Parameters	Value
Initial oil saturation (%)	85
Porosity (%)	30
Average SAGD Pay Thickness (m)	24.4
Vertical Permeability, Kv (mD)	5,132
Horizontal Permeability, Kh (mD)	5,774

Original Bitumen In Place (OBIP)	
Approval area OBIP (Mbbl)	170,155
Operating area OBIP (Mbbl)	93,609

OBIP Calculation Method

$$\mathbf{OBIP} = \mathbf{Rv} \times \boldsymbol{\phi} \times (\mathbf{1\text{-}Sw}) \times \mathbf{FVF}$$

Where:

OBIP: Original bitumen in place

Rv: Rock Volume

ϕ : Porosity

Sw: Initial water saturation

FVF: Formation volume factor (1.001)

2.7 WELL PATTERNS

Pad	Wellpairs	Area (m²)	Average Net Pay (m)	Porosity (%)	Oil Saturation (%)	OBIP (Mbbl)	PBIP (Mbbl)	Cumulative Production (Mbbl)	Current OBIP RF (%)	Current PBIP RF (%)	Estimated Ultimate RF (%)
1	ABM	338,560	27.0	30%	85%	14,731	12,783	8,544	58%	67%	75-85
2	CDE	395,550	23.4	30%	85%	14,895	12,911	6,357	43%	49%	70-80
3	HIJKLN	525,613	23.8	30%	85%	19,704	17,401	12,124	62%	70%	75-85
4	OPQZ	364,068	21.6	30%	85%	12,473	11,364	4,516	36%	40%	65-75
5	RSTUVW	627,926	25.9	30%	85%	25,934	23,870	4,747	18%	20%	65-75
6	XY	148,378	24.7	30%	85%	5,872	4,869	771	13%	16%	60-70

***Some Pad recovery factors have decreased after mapping review*

OBIP= Rv x ϕ x (1-Sw) x FVF

Where:

OBIP → Original bitumen in place

Rv → Rock Volume

ϕ → Porosity

Sw → Initial water saturation

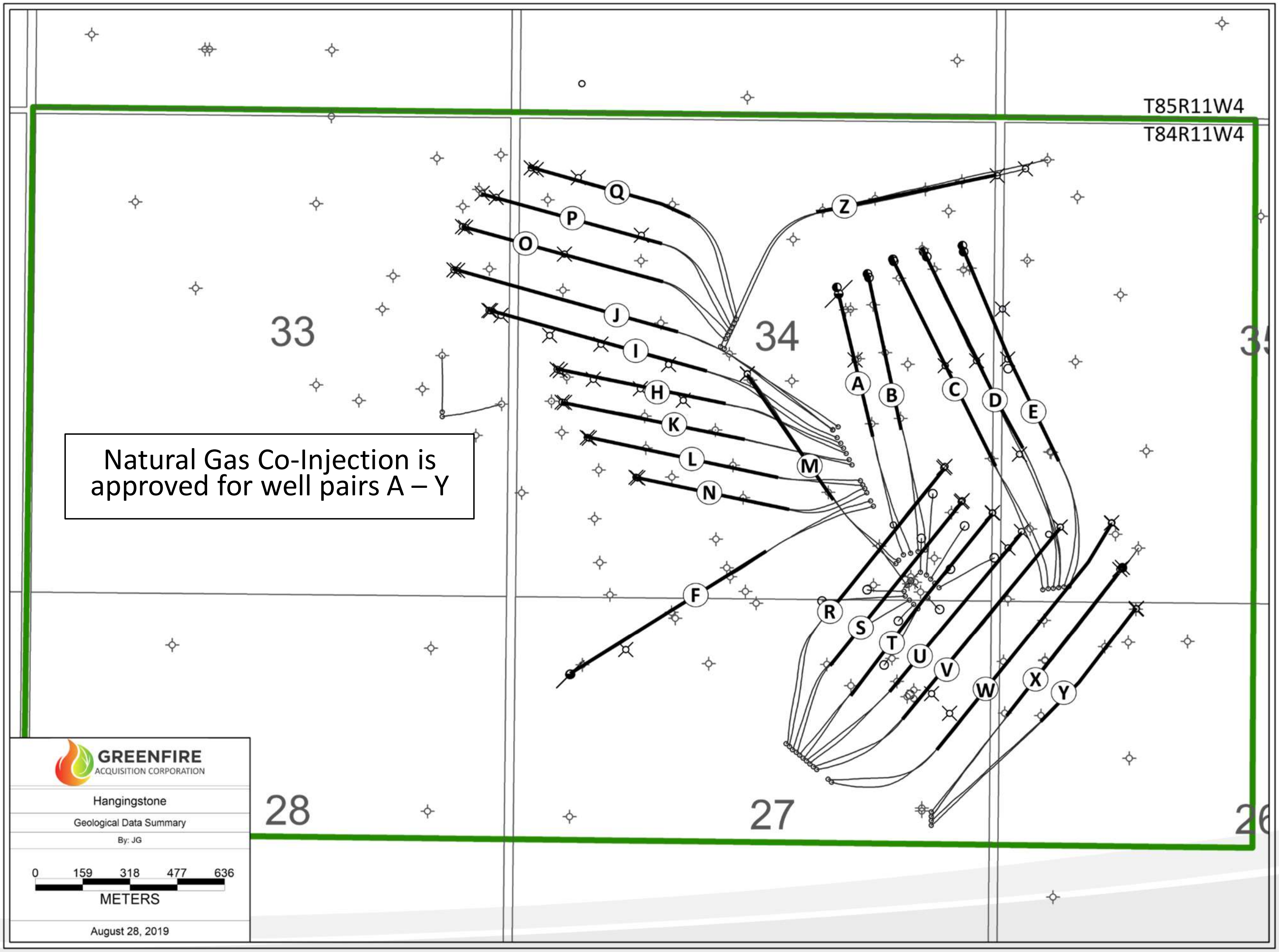
FVF → Formation volume factor (1.001)

2.8 CO-INJECTION

- Approved for full field NCG co-injection (pipeline fuel gas) and to increase injection up to 50 mole percent with steam on a monthly basis
- Recovery is estimated at ~10 – 15 % of injected volumes
- The table provides NCG co-injection carried rates for January to May 2020
  - Average project injection for 2020 was 1.46 e3m3/d
  - Cumulative co-injection for 2020 was 4,203 e3m3
- Greenfire intends to continue with NCG co-injection to assist with reservoir pressure maintenance, pending market conditions as it helps to keep pressure in the reservoir while allocation steam around the field
- Greenfire has observed no negative impacts on well integrity as the gas is mixed with hot steam during injection

Pad	Well	Max Month, Daily Avg NCG Rate (sm3/d)	Avg NCG Rate (sm3/d)	e3m3
1	B	7	2	0.0
	M	3,293	1,618	3.3
2	C	383	103	0.4
	D	2,485	816	2.5
	E	3,904	1,053	3.9
3	H	270	56	0.3
	I	6	3	0.0
	J	777	160	0.8
	K	11	8	0.0
	L	6	1	0.0
	N	-	-	-
4	O	5,337	2,382	5.3
	P	5,337	2,382	5.3
	Q	564	147	0.6
5	R	3,872	1,408	3.9
	S	6,529	2,681	6.5
	T	7,369	5,162	7.4
	U	10,385	6,313	10.4
	V	4,597	1,488	4.6
	W	3,628	2,052	3.6
6	X	-	-	
	Y	-	-	

2.8 CO-INJECTION WELL LOCATIONS



GREENFIRE
ACQUISITION CORP.

SECTION 3.0 – SURFACE

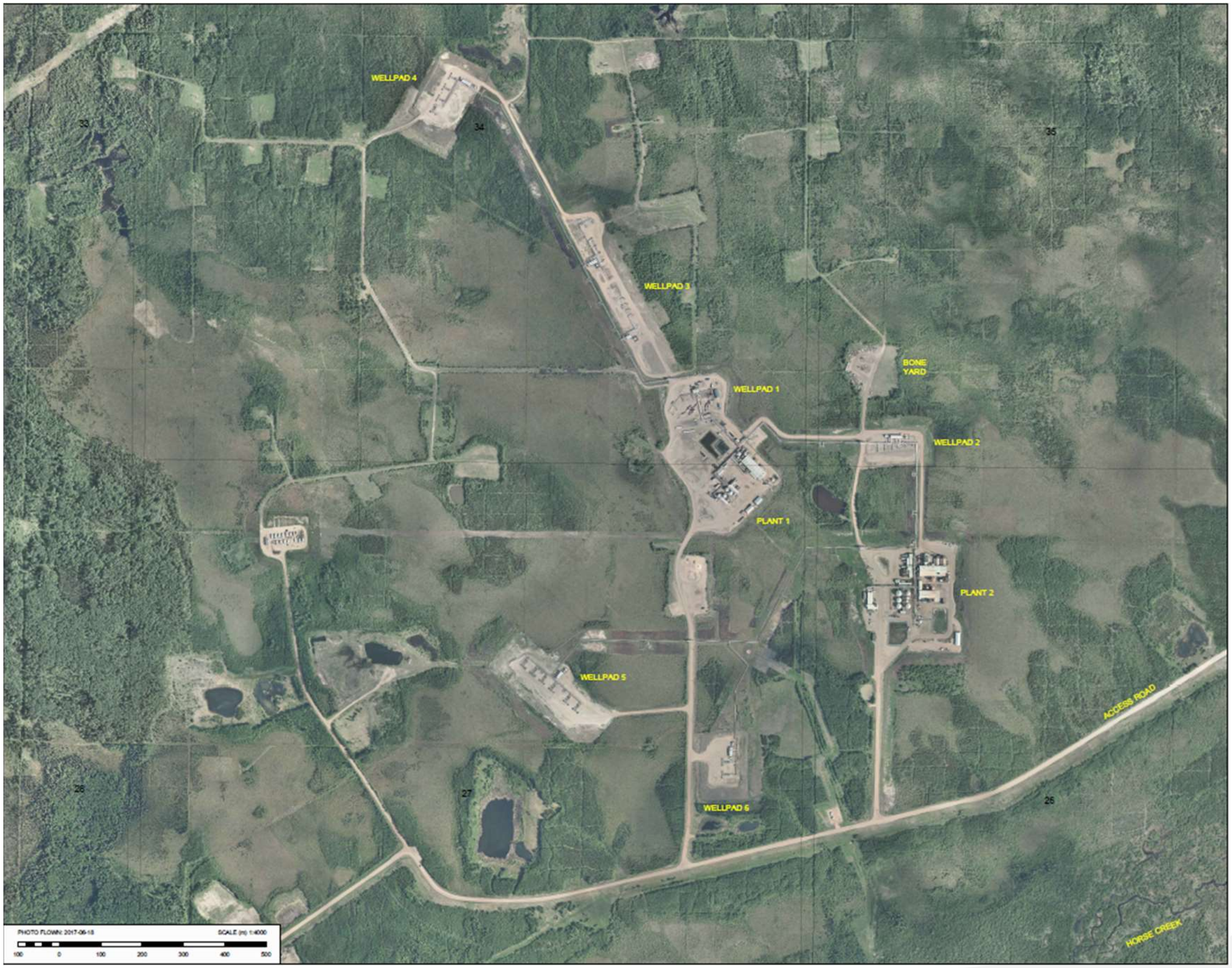
HANGINGSTONE SAGD PROJECT

Scheme Approval No. 8788, as amended

EPEA Approval No. 1604, as amended

September 2019

3.1 DEVELOPMENT AREA INFRASTRUCTURE



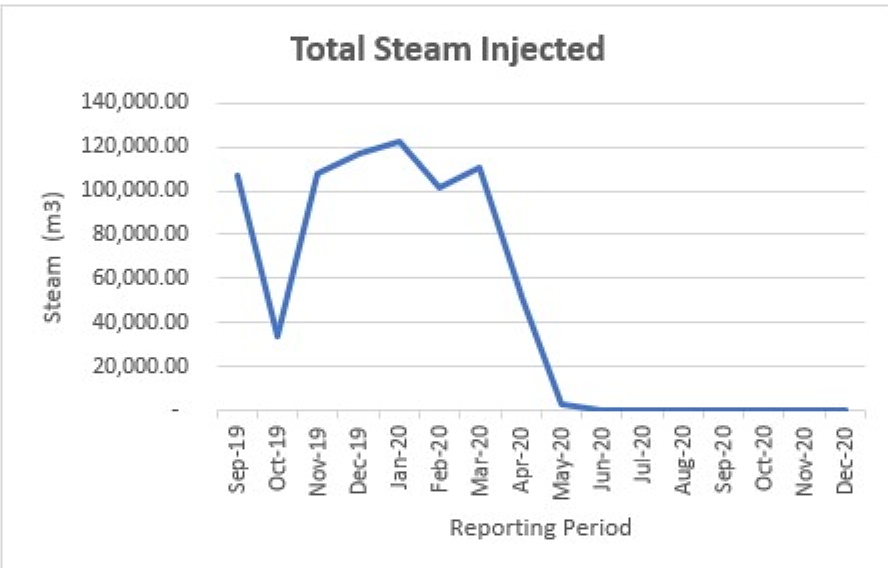
**There are no immediate planned surface infrastructure*

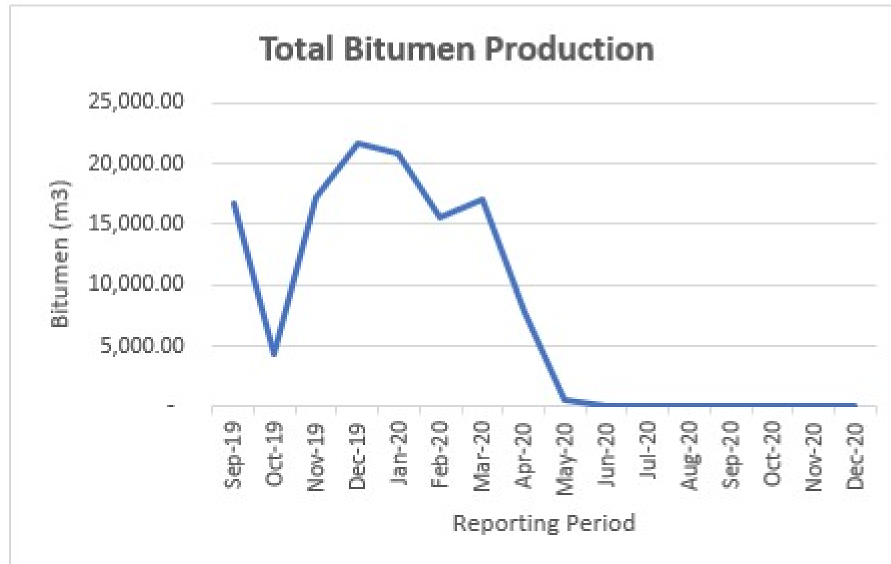
3.2 CENTRAL PROCESSING FACILITY MODIFICATIONS

- There have been no modifications to the Hangingstone Project central processing facility for the report period that has required an AER application approval

3.3 OPERATIONAL BITUMEN AND STEAM RATES

- The following are the steam and bitumen rates for the Project for the Reporting Period. The rates matched the forecasted profiles.





Note: The Project undertook a plant turnaround in October 2019, which accounts for the lower steam and bitumen rates

GREENFIRE ACQUISITION CORP.

SECTION 4.0 – HISTORICAL & UPCOMING ACTIVITY

HANGINGSTONE SAGD PROJECT

Scheme Approval No. 8788, as amended

EPEA Approval No. 1604, as amended

September 2019

4.1 SUSPENSION AND ABANDONMENT ACTIVITY

- The Hangingstone Project was fully suspended from May 2020 to the end of December 2020.
  - The Project and all associated production well pads are anticipated to be reactivated in 2021.
- The Project was suspended by the previous operator of the Project as a result of the economic developments and the ongoing pressures associated with the COVID-19 global pandemic throughout 2020.
- There are no well patterns currently under active blow-down or ramp-down

4.2 REGULATORY AND OPERATIONAL CHANGES

- Regulatory Approvals for the Reporting Period
  - Renewal of EPEA Approval No. 1604
    - Application Submission: November 12, 2019
    - Application Approved: January 28, 2020
    - New Expiry: December 31, 2029
- There were no events for the reporting period that could materially affect scheme performance or energy or material balances (e.g., no phase expansions, no material changes in injection strategy, and no major infrastructure changes
- Successes
  - Plant performed well with high uptime for steam production
  - MVR exceeded design parameters leading to high levels of water recovery
- Issues
  - There were some issue with exchangers (plugging) and instrumentation
  - VRU under-performed for the reporting period
- There were no pilots or major technical innovations conducted by the previous operator at the Project during the reporting period.

4.3 COMPLIANCE HISTORY

- AER Reportable Incidents
  - October 2019: Pipeline Valve Release
    - Valve left open after turnaround
    - Small amount of fluid was released onto the ROW
    - Cleaned up all released fluid at the time of incident
    - Additional remediation work pending in 2021
  - December 2019: Produced Water release
    - Level indicator failure on facility equipment
    - Small amount of water released onto the facility lease site
    - Cleaned up at the time of incident.
    - Remediation completed. Incident closed with AER
  - February 2020: Wellhead Leak
    - Wellhead crack
    - Effluent from wellhead released onto well pad. No fluid exited the lease
    - Cleaned up majority of liquid at time of incident.
    - Additional remediation work pending in 2021
  - December 2020: Pipeline Release
    - Freeze induced cracking of the quench water pipeline
    - Small amount of fluid was released onto facility lease site
    - Clean-up at time of incident
    - Remediation Complete. Incident closed with AER
- *EPEA* Contraventions
  - The facility was in suspension from May to December 2020. During that time, no environmental testing or reporting was completed. The contravention was reported to the AER in 2021 and the matter is being brought back into compliance.

4.4 FUTURE PLANS

- As discussed, the Project was in suspension from May to December 2020. The Project is expected to return to its pre-suspension production levels in 2021.
- Currently, there are no major delineation, seismic, well pattern, or infrastructure activities planned for the Project over the next five years.
- The Corporation's focus will be on returned the Project to pre-suspension production levels and will look at potential de-bottlenecking opportunities at the central processing facility
- The following applications are expected to be submitted to the AER in 2021:
  - Water Act Licence Renewal Application