First Ever Field Pilot on Alaska's North Slope to Validate the Use of Polymer Floods for Heavy Oil Enhanced Oil Recovery (EOR)

a.k.a Alaska North Slope Field Laboratory (ANSFL)

Project Number DE-FE0031606

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U.S. Department of Energy
National Energy Technology Laboratory
Resource Sustainability Project Review Meeting
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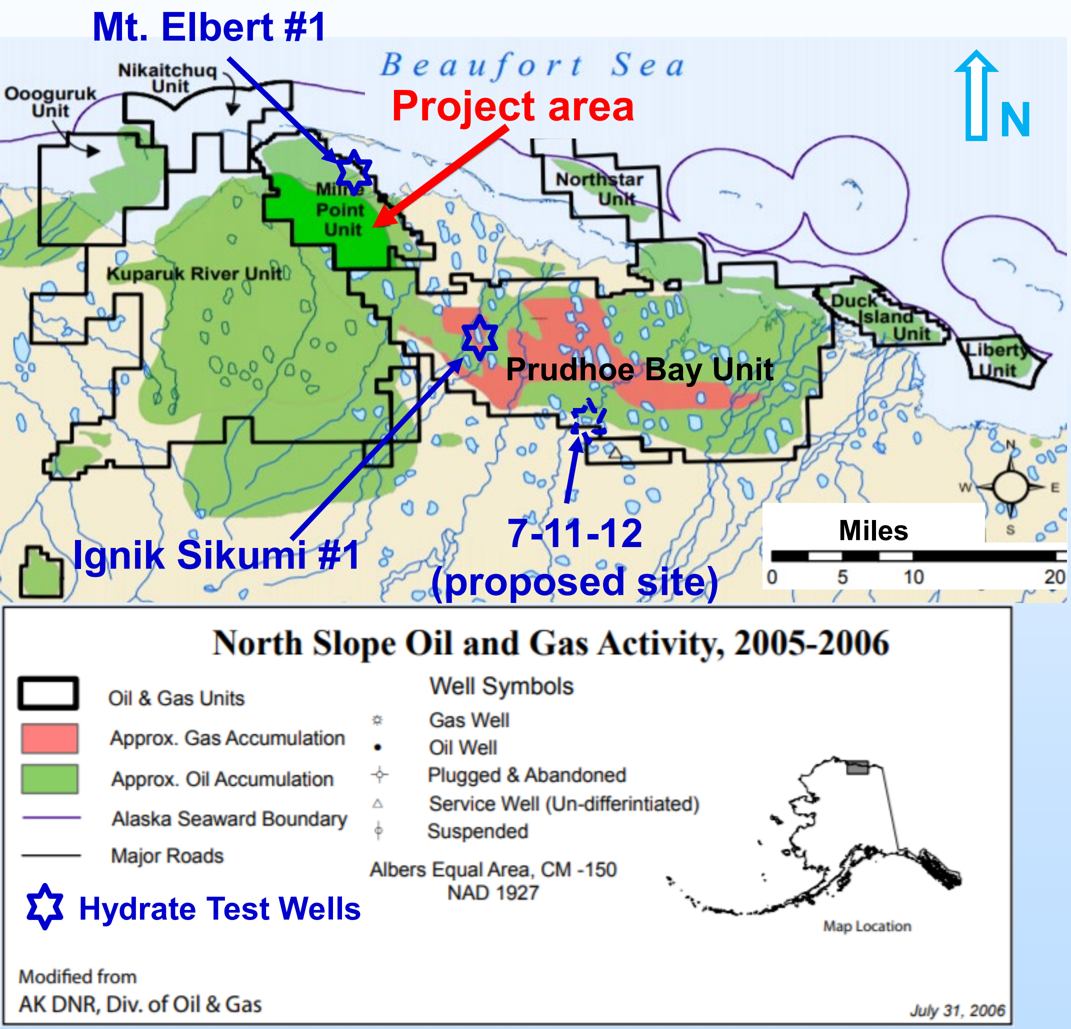
Project Overview

- Funding
  - Total Award Value: $9,715,350
  - DOE Share: $7,131,065
  - Performer or Cost Share: $2,584,285
- Overall Project Performance Dates
  - 06/01/2018 – 10/31/2022
- Project Participants
  - Prime Performer: University of Alaska Fairbanks
  - Sub-recipients: Hilcorp Alaska; Missouri University of Science and Technology; New Mexico Institute of Mining and Technology; University of North Dakota

Overall Project Objectives

- Integrate polymer flooding, low salinity water flooding, horizontal wells, and injection conformance control treatments into one process to significantly enhance recovery for heavy oil reservoirs, via:
  - ✓ Assessment of polymer injectivity into the Schrader Bluff formations
  - ✓ Optimization of polymer viscosity/concentration
  - ✓ Determination of polymer retention
  - ✓ Methods in place for conformance control, if necessary
  - ✓ Effective treatment of produced stream (containing spent polymer), including mitigation of heater tube fouling
- Obtain valuable field polymer flood performance data
- A forecast-worthy history matched reservoir simulation model

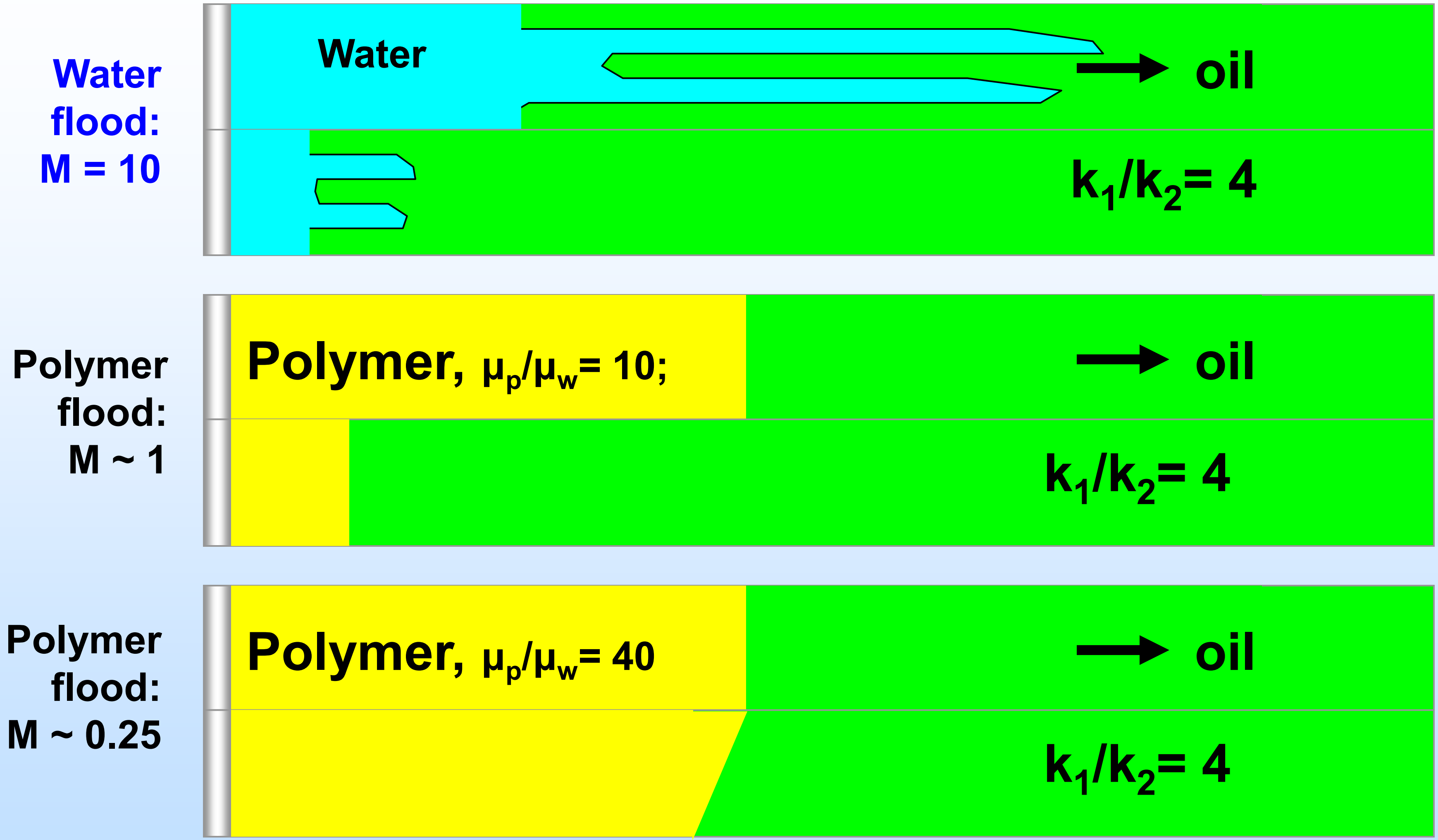
ANSFL Technology Background



Source: AK DNR, Division of Oil & Gas

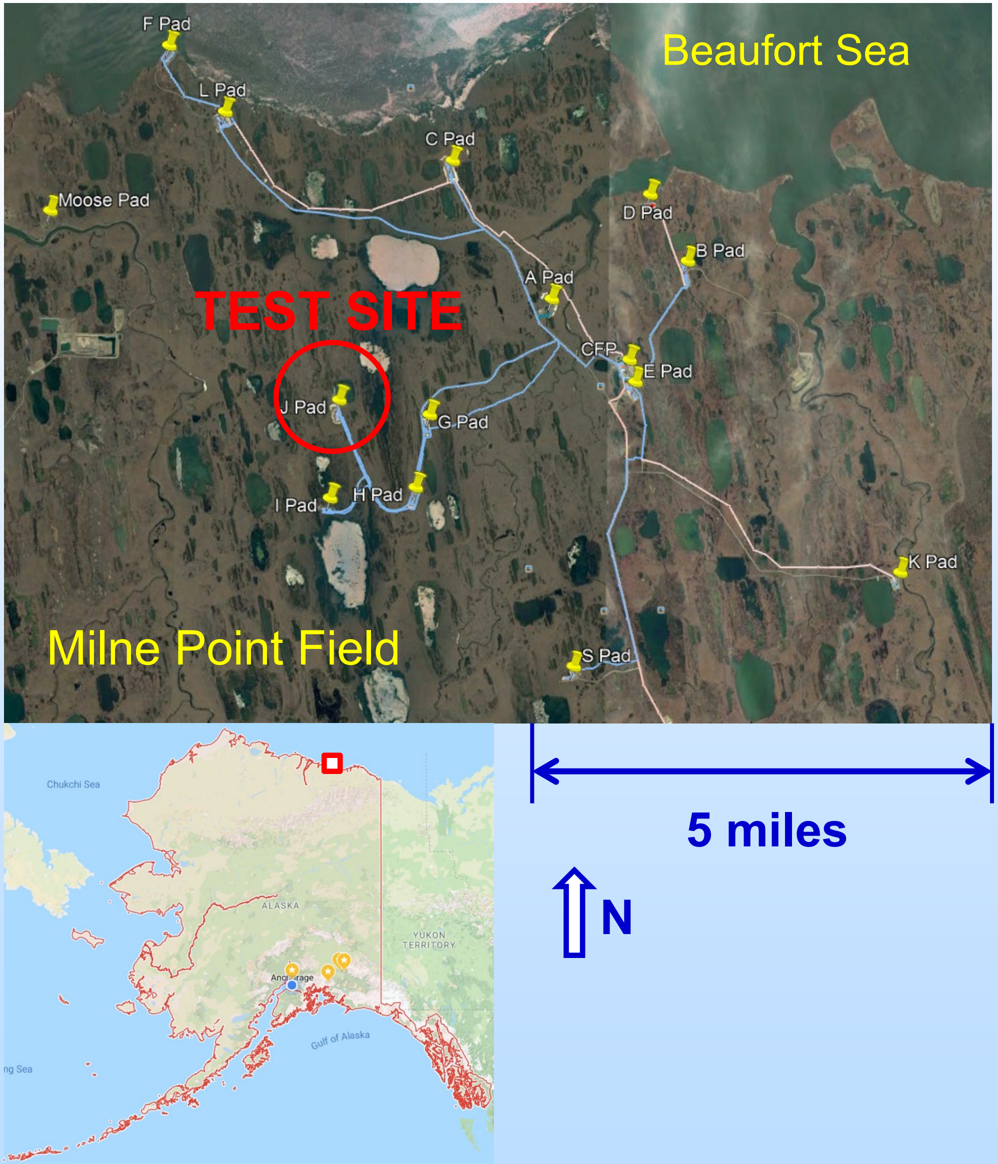
- Significant heavy oil resource (20-25 billion bbls); too large to ignore.
- Poor waterflood sweep due to mobility contrast.
- Limitation of deploying thermal methods due to "permafrost".
- Light crude diluent still available for high viscosity oil transport through Trans Alaska Pipeline System.

Sweep Efficiency – A Key Factor



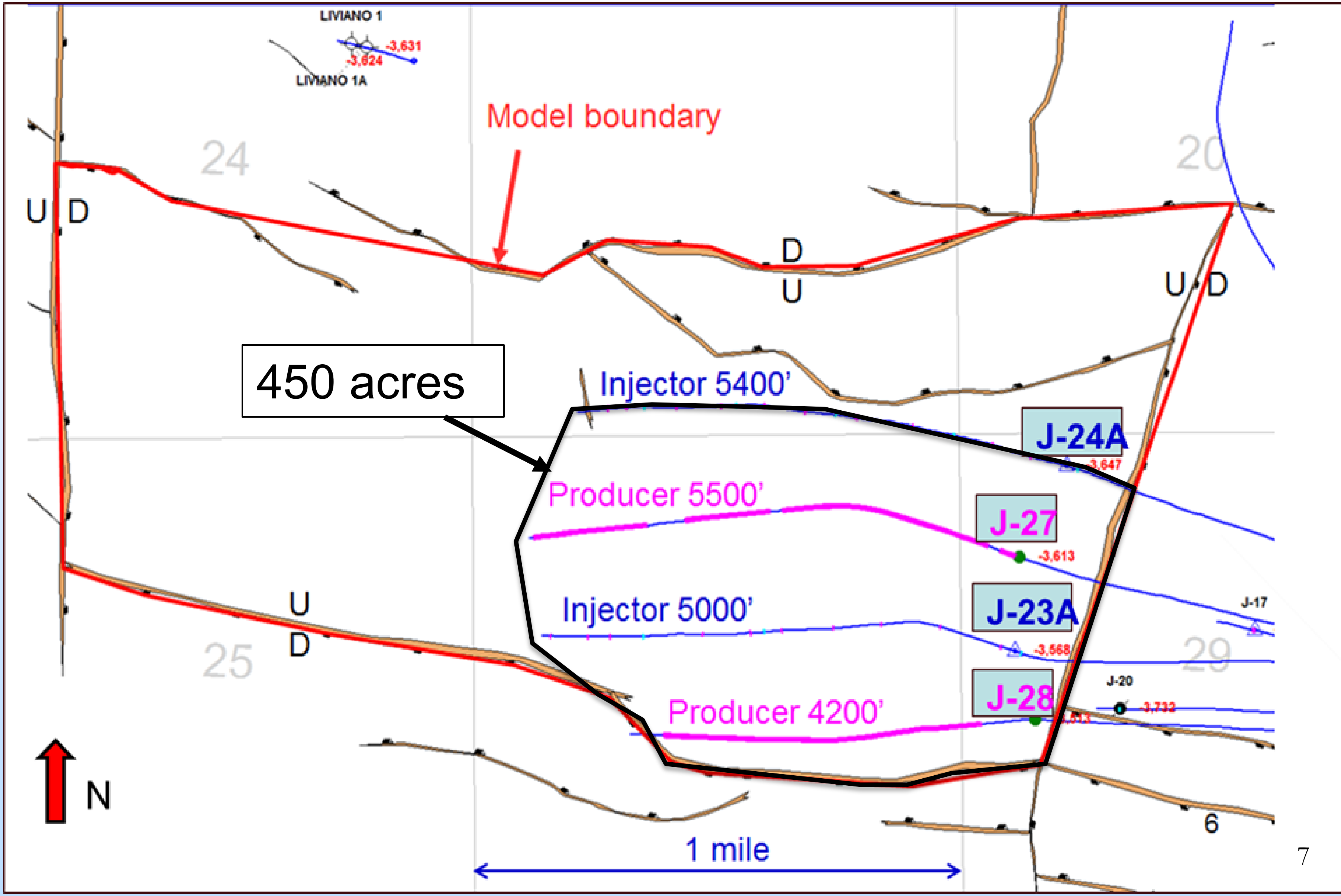
- Want to make the water flood mobility ratio (M) favorable.
- Want to overcome the permeability contrast.

Test Site and Reservoir

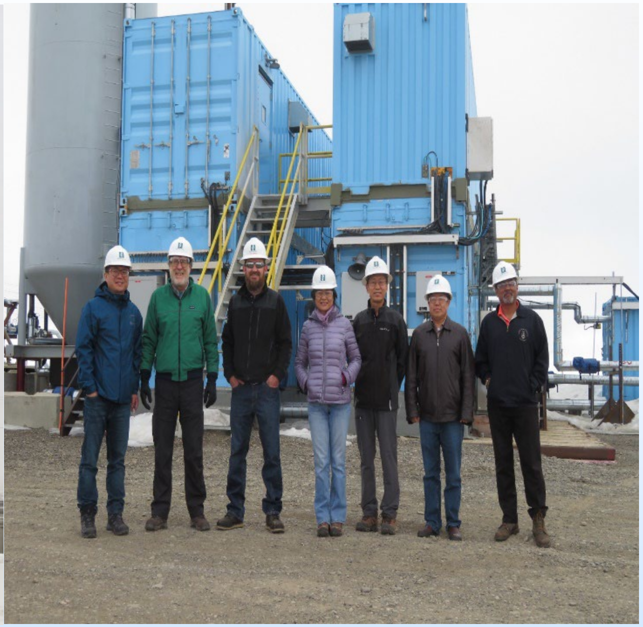


- Milne Point (MPU), 30 miles NW of Prudhoe Bay.
- Schrader Bluff formation, Porosity: 31–35%, Permeability: 100–3,000 mD.
- Low reservoir temperature: ~70°F.
- Oil API: ~15 with in-situ oil viscosity of 330 cP.
- Low salinity source water: 2,500 ppm.

Pilot Wells and Patterns



Polymer Unit



Technical Approach/Project Scope

- Laboratory corefloods (***Tasks 2 and 3***)
  - optimization of injected polymer viscosity/concentration, quantification and retention.
  - optimization of injection water salinity and identification of conformance control strategies.
- Reservoir simulation (***Task 4***)
  - history matching (HM) of laboratory corefloods, field waterflood, and polymer flood pilot.
  - optimization of the polymer injection strategy for the project reservoir.
  - scale up to full field oil recovery from polymer injection.

Technical Approach/Project Scope

- Implementation of polymer flood field pilot (***Task 5***)
  - prior lab studies used in initial polymer selection.
  - interactively integrate lab tests, reservoir simulations, and field tests.
  - long time (years) required for polymer injection to quantify the benefit.
- Flow assurance (***Task 6 and extension***)
  - oil-water separation to specifications, tests on multiple emulsion breakers, different influencing variables.
  - potential fouling of heater tubes.

- Economic evaluation (***Task 7***)

Key Milestones

Activity	Milestones	Planned (completion) reporting
Laboratory Experiments for Optimization of Injected Polymer Viscosity/Concentration and Quantification of Polymer Retention	• Continuous lab tests and monitoring of the field project to optimize polymer type and concentration and quantify polymer retention.	• Quarterly/Bi-weekly review meetings
Laboratory Experiments for Optimization of Injection Water Salinity and Identification of Contingencies in Premature Polymer Breakthrough in the Field	• Distinguish water salinity and polymer effect on Sor. • Continuous monitoring of the field project so that injection conformance can be maintained.	• 09/30/2020 • Quarterly/Bi-weekly review meetings
Reservoir Simulation Studies for Coreflooding Experiments and Optimization of Field Pilot Test Injection Strategy	• Continuous updating of the reservoir simulation model, and report, to improve predictability of the models and quantify uncertainty associated with predicted reservoir performance.	• Quarterly/Bi-weekly review meetings
Implementation of Polymer Flood Field Pilot in Milne Point	• Continuous polymer injection and monitoring injection conformance. Gel treatments or mechanical isolations may be performed to ensure polymer injection is relatively uniform along wellbores. • Adjust polymer injection parameters as indicated by lab tests and simulation results.	• Quarterly/Bi-weekly review meetings • Quarterly/Bi-weekly review meetings

Decision Points and Success Criteria

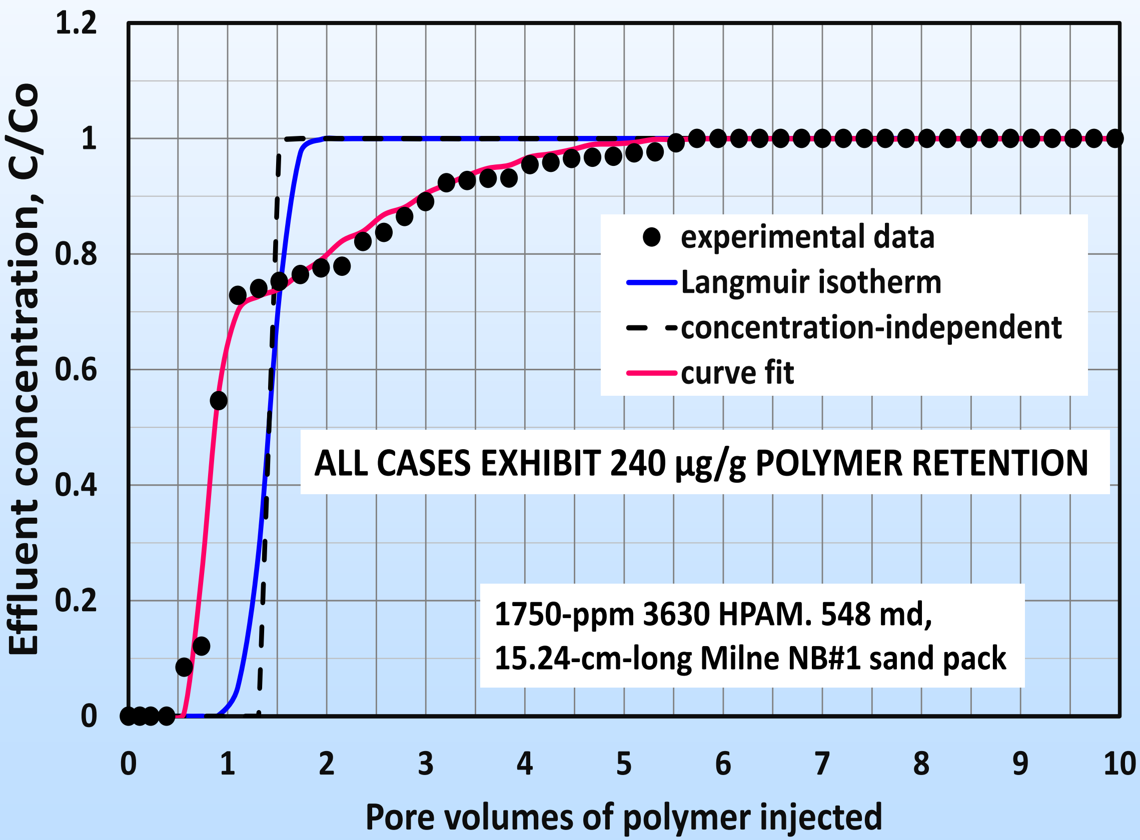
- ✓ Conformance control – even distribution of polymer
- ✓ Polymer injectivity – sustained injection rates for maximum sweep
- ✓ Produced polymer impact on downstream facilities – safe operating envelope for emulsion and heater fouling
- ✓ Feasibility of polymer flood – commercial scale

Risk and Mitigation Strategies

Risk Category	Description of Risk	Probability (Low, Moderate, High)	Impact (Low, Moderate, High)	Risk Management Mitigation and Response Strategies
Scientific/Technical	Reservoir Simulation Assumptions and Limitations	Low	Low	Assumptions and limitations are "inherent" in any numerical modeling; however, a robust reservoir simulation can be achieved provided the physics is honored and accurate and reliable coreflood and field data is employed in obtaining a history match, which will be the mitigation strategy.
	Upscaling of Lab Data to Field Scale	Low	Moderate	Scaling factors or ratios will be used to upscale the core level data to reservoir scale, for e.g., saturations, relative permeabilities, Darcy velocities. Subsequently, results will be verified by comparing the data at both scales.
Resource/Logistics	Test Site and Well Selections	Low	Low	The use of existing wells reduces risks associated with well availability and timing of operations. There are two pairs of injector-producer in the project area; i.e., if one fails the other can be employed. Additionally, all the required permits are in place.
	Polymer Mixing/Pumping Unit	Moderate	Moderate to High	Although the unit is custom designed for Arctic operations, a certain element of (malfunctioning) risk exists as the polymer injection commencing in summer 2018 transitions into winter weather conditions. Hilcorp will work with the vendor in earnest to address any operational issues.
	Polymer Injectivity	Moderate	High	Injectivity test performed on lower permeability sands have been successful; however, should problems occur in the test wells, NMT will recommend polymer of a (lower) molecular weight and/or concentration to achieve an adequate injection rate.

Summary Results: Polymer retention

What does high retention mean for the pilot?

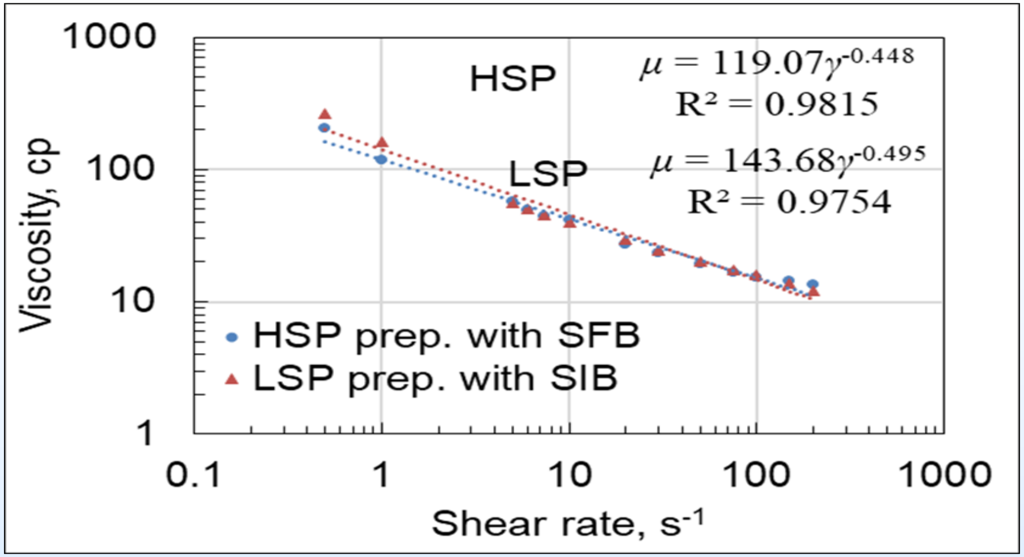


- Conventional methods (fractional flow calculations or simulators) assume either concentration-independent polymer retention or the Langmuir isotherm. Both methods predict that retention delays polymer bank (and the oil bank) propagation by a factor directly proportional to retention.
- Actual retention in Milne Point core material shows NO delay in propagation, but the polymer concentration arrives with only ~70% of the injected value.
- This must be (and has been) incorporated into Milne Point simulation projections.

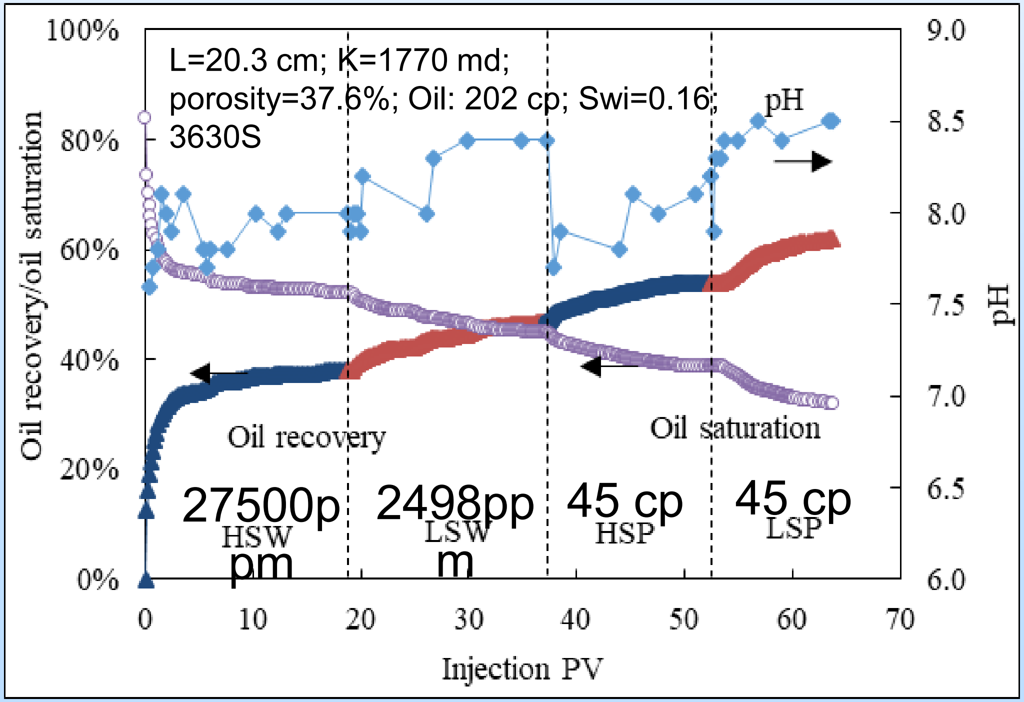
What influences polymer retention?

- At Milne Point, polymer retention and the “tailing” effect is caused by illite. Kaolinite will act similar to illite.
  - Polymer retention at Milne Point (and on illite) **IS NOT** sensitive to flow rate, polymer concentration, molecular weight degree of hydrolysis, NaCl or KCl concentration, core length, permeability, heterogeneity, or whether the core was preserved, native state, cleaned of oil, or cleaned and re-saturated with oil, or cleaned, re-saturated, and aged with oil.
- Polymer retention **IS** very sensitive to divalent cation content (Ca, Mg).
- A small amount (~5%) of ATBS monomer incorporated into HPAM can almost eliminate polymer retention, and also alleviate fouling issues.

Summary Results: Low salinity effect



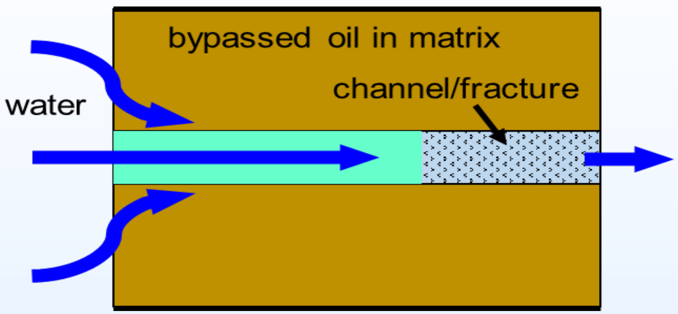
- Polymer Viscosity: 45 cp at 7.3 s^{-1}
- Polymer Conc.: 1400 vs. 2300 ppm
- Save 1/3 of polymer when LowSal water is used

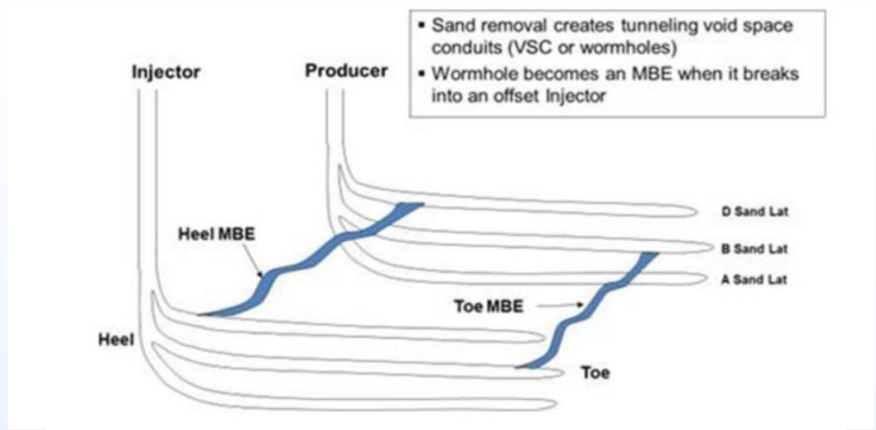


- LSPF after extensive WF and HSPF: 8.0% OOIP (61.9)
- pH change: significant increase during LSPF and synchronized well with the incremental oil recovery process
- LSPF after secondary HSPF: 5.7% OOIP (76.9%)
- HSPF after LSPF: 0.4% OOIP

Summary Results: Conformance control

- Potential Conformance Problems

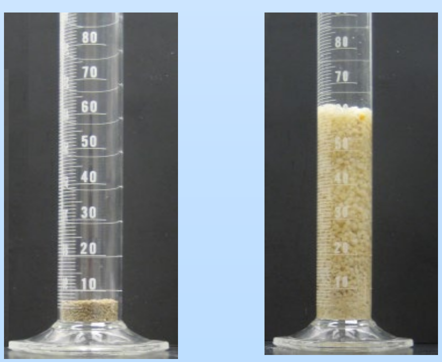




Simplistic drawing of formation of MBE in heel and toe of Producer/Injector pair (Peirce 2014).

- Screen and evaluate preformed particle gels (PPG) that can swell 20-50 times in formation water and injection water.
- Develop in-situ polymer gel recipe that can be used at the low temperature reservoir conditions.
- Investigate the potential of microgel and in-situ gels to reduce water cut and produced polymer concentration using experiments and simulation

PPG

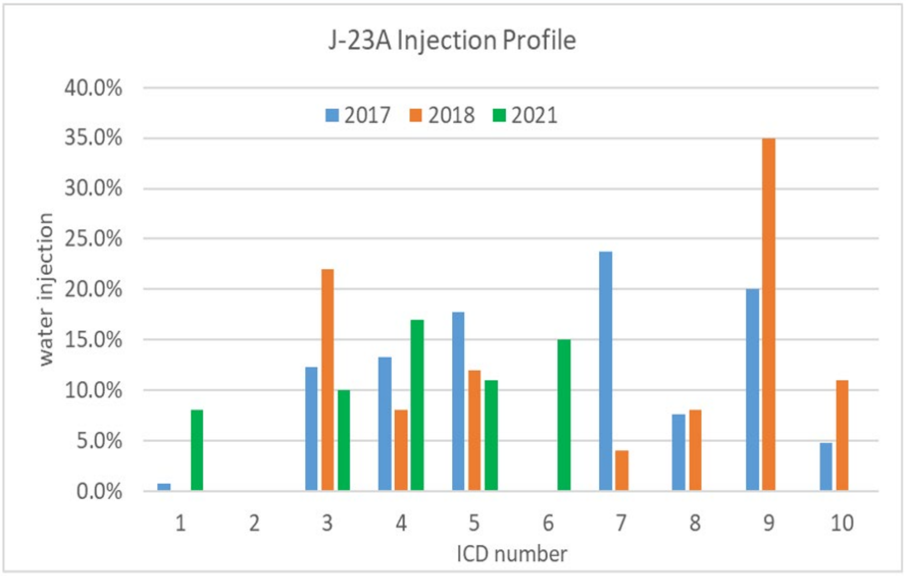


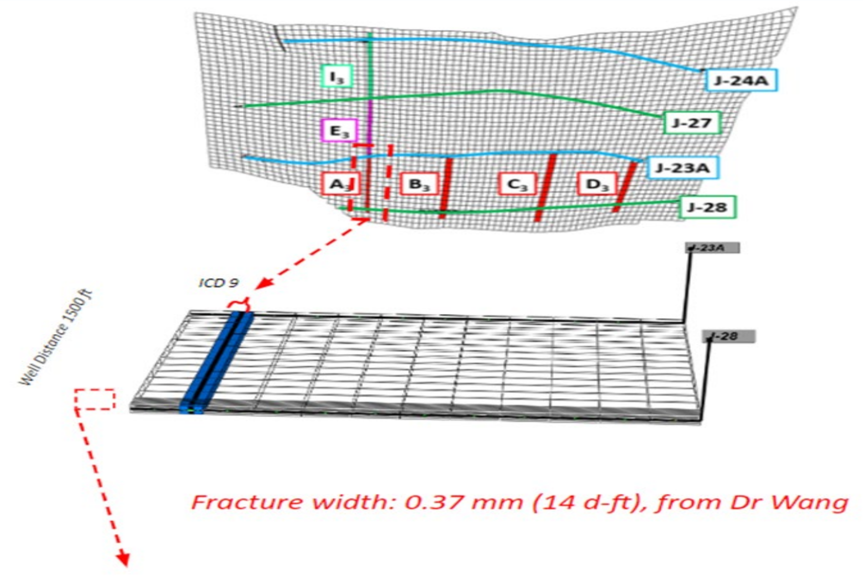
(a) Before swelling (b) After swelling

In-situ Polymer Gels

40:1 60:1 80:1 100:1

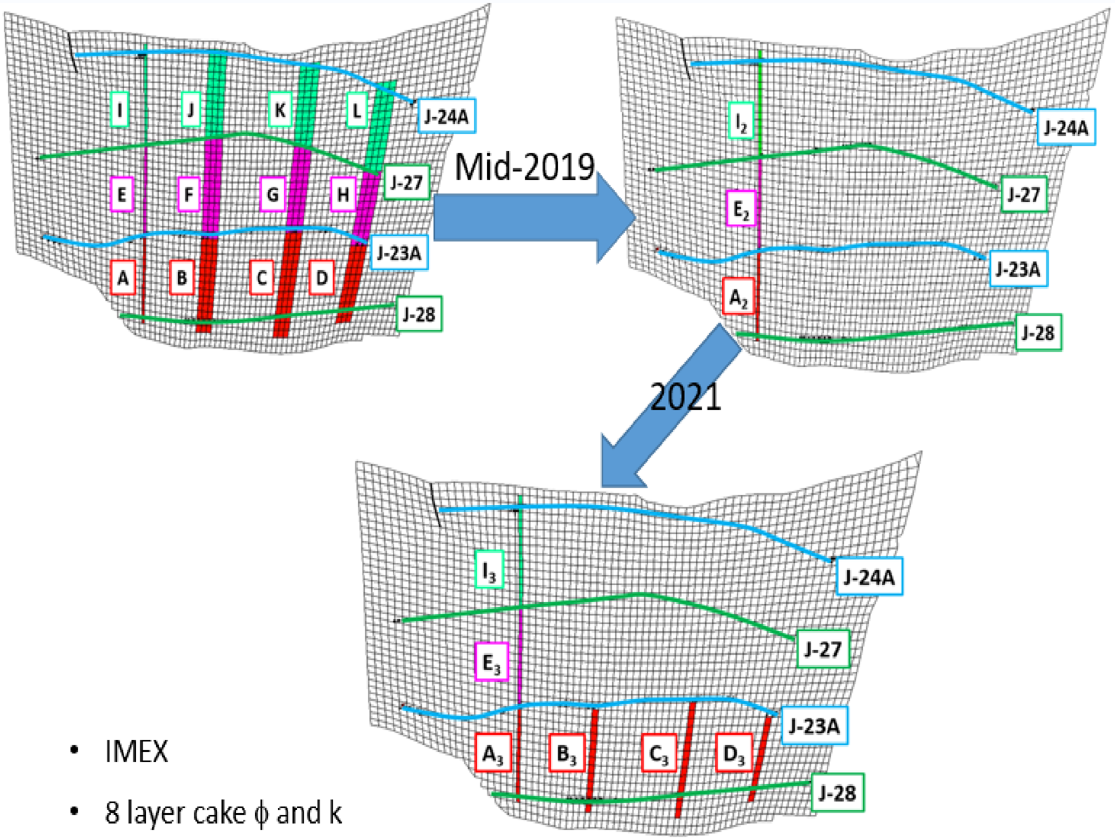
Well Candidate and Gel Treatment Design

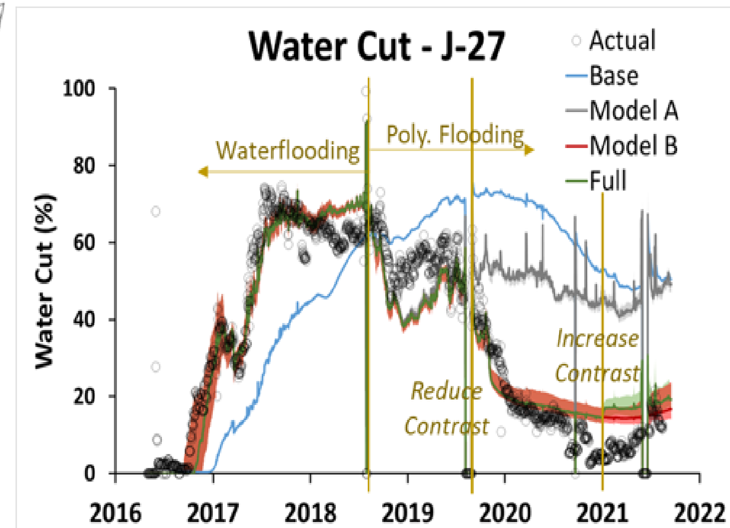


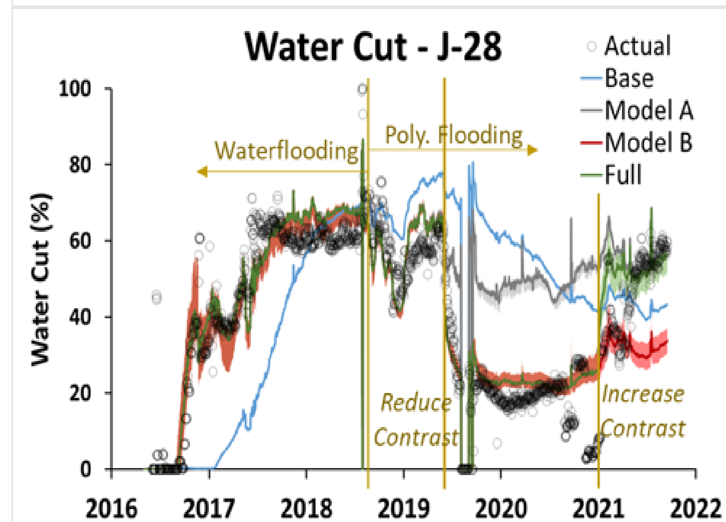


- **Recommendation: Conformance control treatment when WC>80%**
- **Tests to be done before treatments**
    1. Injection profile test
    2. Drawdown test and step-rate test for target ICD
- **Gel treatment design based on current information**
    1. Gel selection：200 bbls 5% AB055+500 ppm CrAc + 125 $AlCl_3$
    2. Injection rate: depending on step-rate test results
    3. Injection pressure control: less than 80% breakdown pressure
- **Injection Mode**: Using coil tubing to inject the plugging agent into ICD 9 only

Summary Results: Reservoir Simulation



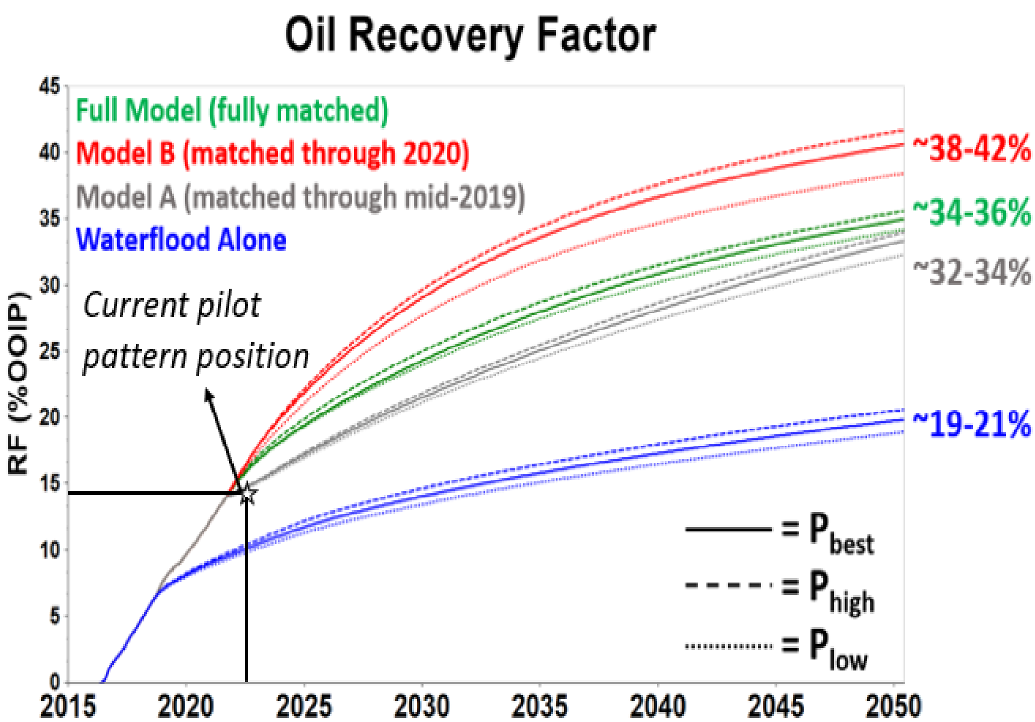




- IMEX
- 8 layer cake ϕ and k
- Single PVT and k_{rs} based on lab data
- μ_{HPAM} = f(conc. & shear rate); retention from laboratory measurements
- "Tailing effect" included and IAPV = 0 and RRF = 1 based on lab experiments

Figure sources: Keith et al. (2022)

Reservoir Simulation Forecasts

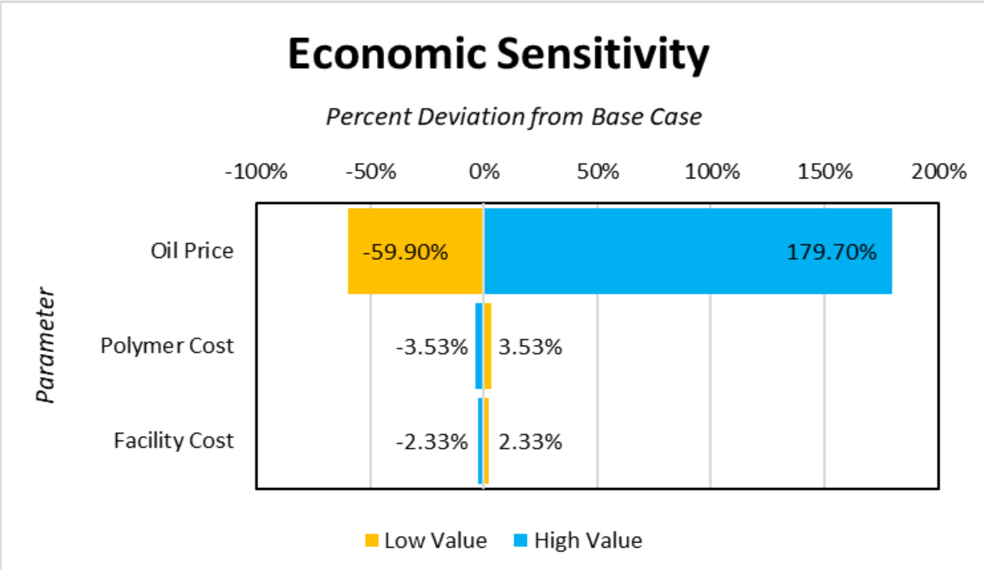


Constraints: Polymer Flood			
Well	Liquid Rate (STB/D)	BHP (psi)	Poly. Conc. (ppm)
J-23A	1500	2600	1200
J-24A	500	2600	1200
J-27	1000	800	-
J-28	1000	650	-

Constraints: Waterflood			
Well	Liquid Rate (STB/D)	BHP (psi)	Poly. Conc. (ppm)
J-23A	2100	2100	0
J-24A	1600	2200	0
J-27	2200	900	-
J-28	1500	700	-

Figure sources: Keith et al. (2022)

Economic Evaluation



Design Sensitivity analysis

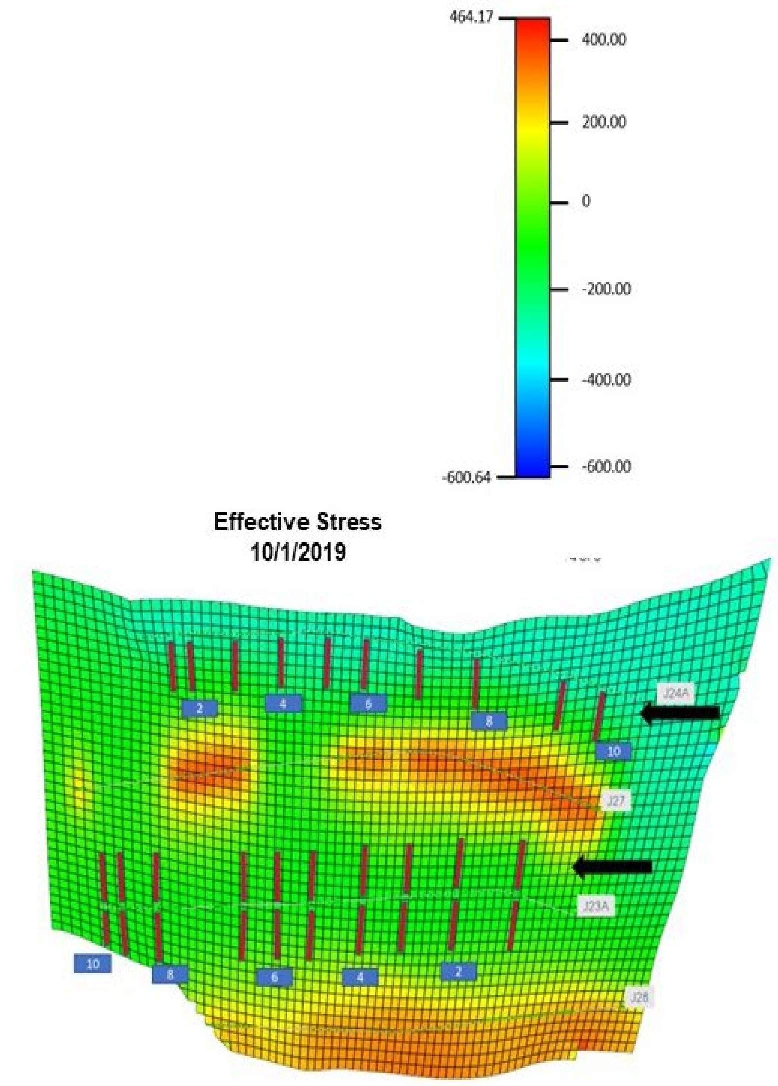
- Polymer Concentration
- Throughput Rate
- Polymer Injection Duration
- Polymer Injection Start Time
- Well spacing

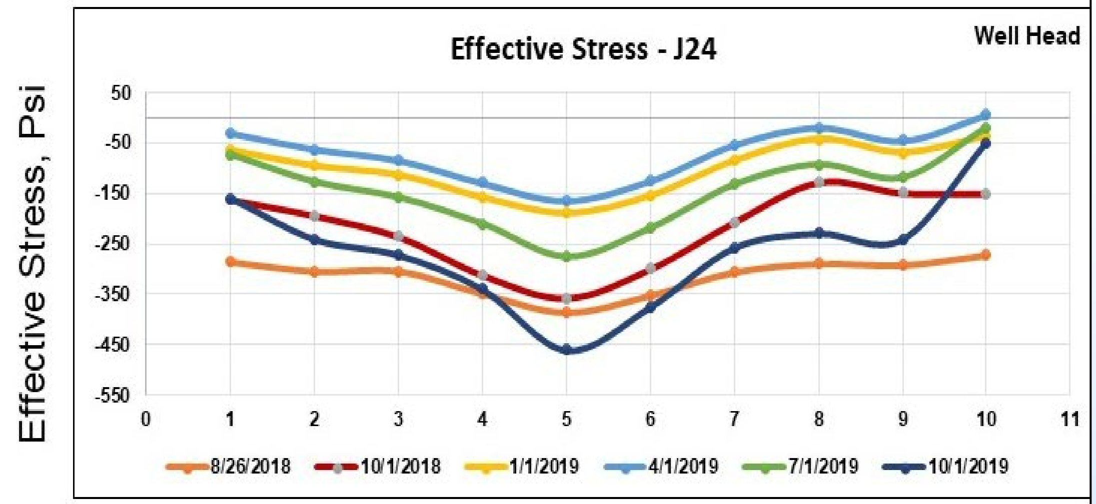
Polymer Flood Incremental Economic Performance

Case	FULL MODEL			MODEL B			MODEL A		
	P_{best}	P_{high}	P_{low}	P_{best}	P_{high}	P_{low}	P_{best}	P_{high}	P_{low}
NPV ($ Million)	**42.9**	45.5	41.3	61.4	63.9	55.5	31.9	33.4	29.9
Discounted PI Ratio	**5.05**	5.36	4.87	7.36	7.63	6.71	3.76	3.92	3.52
Development Cost ($/bbl)	**8.35**	8.02	8.80	5.91	5.69	6.51	9.34	8.93	10.14
Incremental Recovery Factor (%)	**15.1**	15.7	14.3	20.7	21.8	18.6	13.5	14.1	12.4

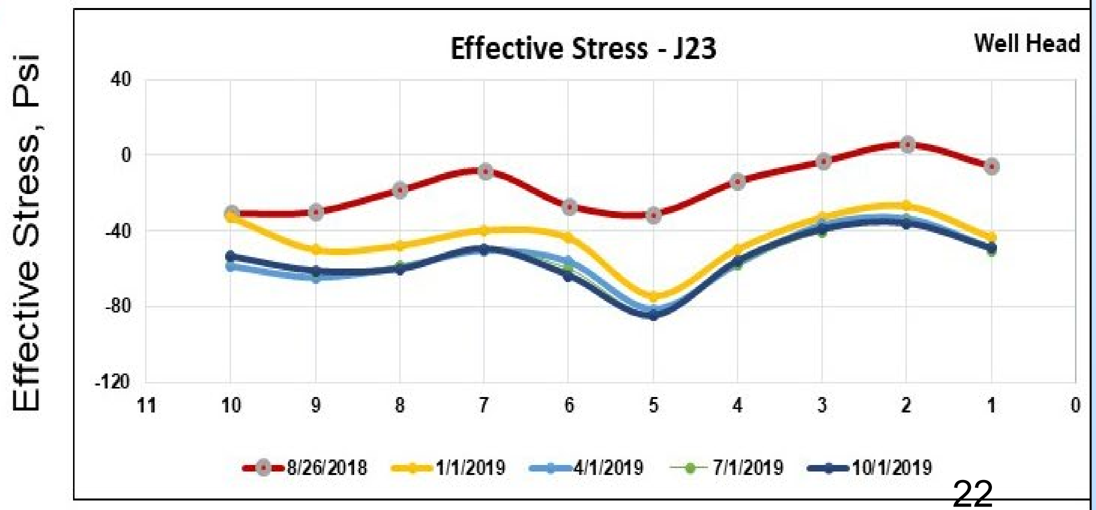
Figure sources: Keith et al. (2022)

Geomechanical Effect



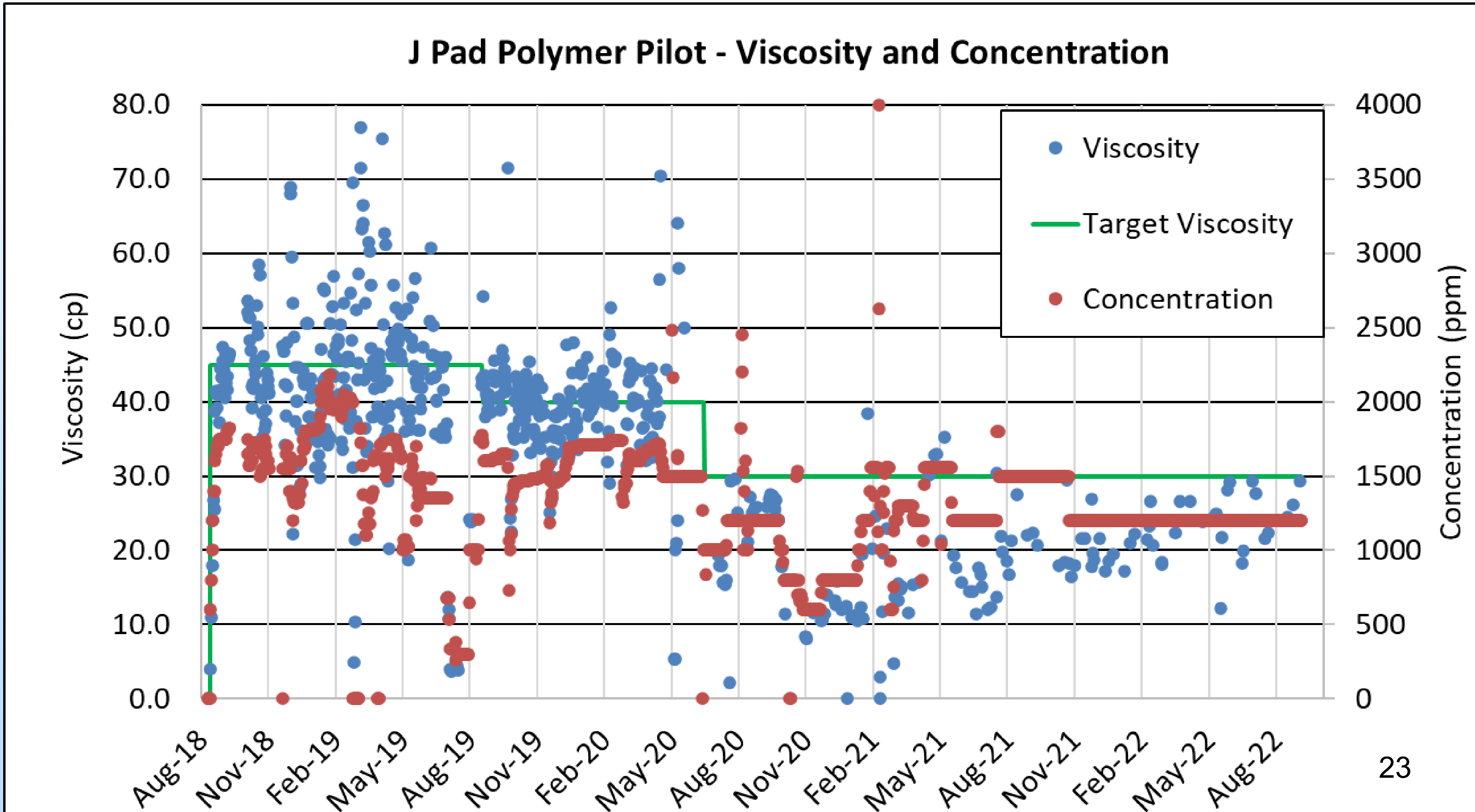


ICD #



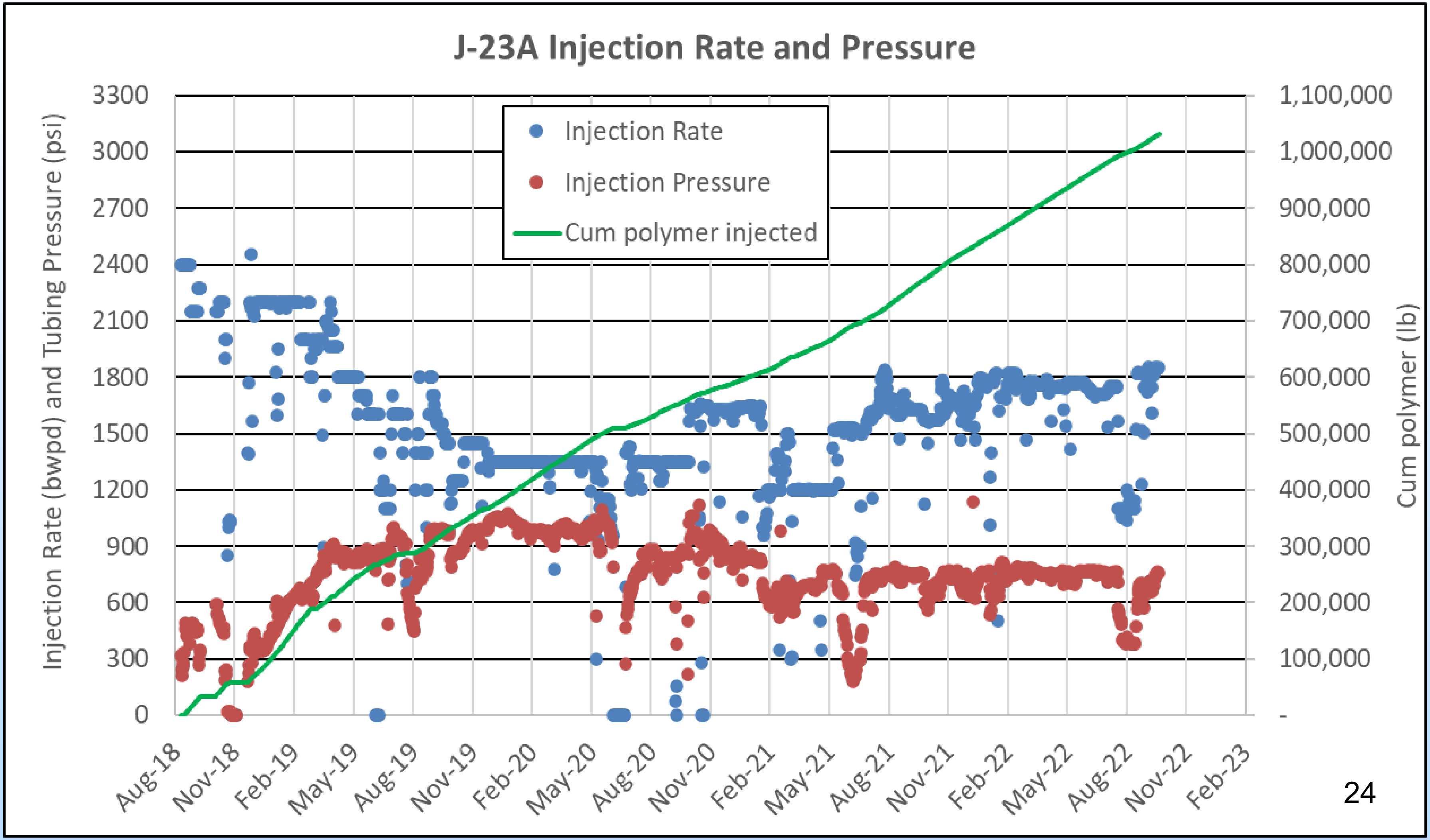
Pilot performance: Viscosity and Concentration

- Current concentration: 1200 ppm, Flopaam 3630;
- $\mu \sim 29\ cP$; β Filter ratio 1.46, UT FR = 1.04 used for QC
- Cum polymer injected: 1,408,000 lbs



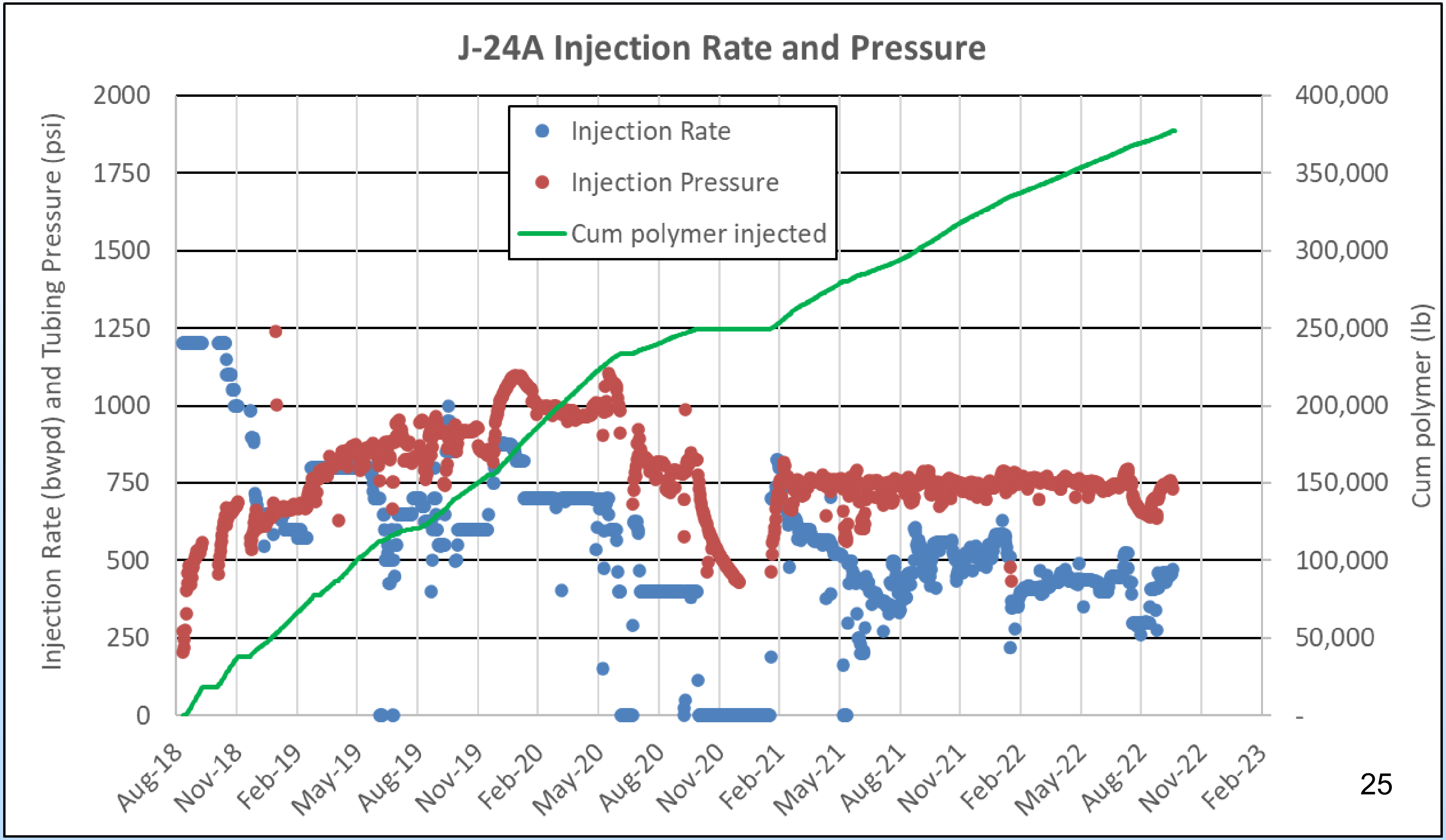
J-23A Injection Performance

- Stable injection rate 1850 bpd at 755 psi
- Cum polymer injected: 1,030,000 lbs

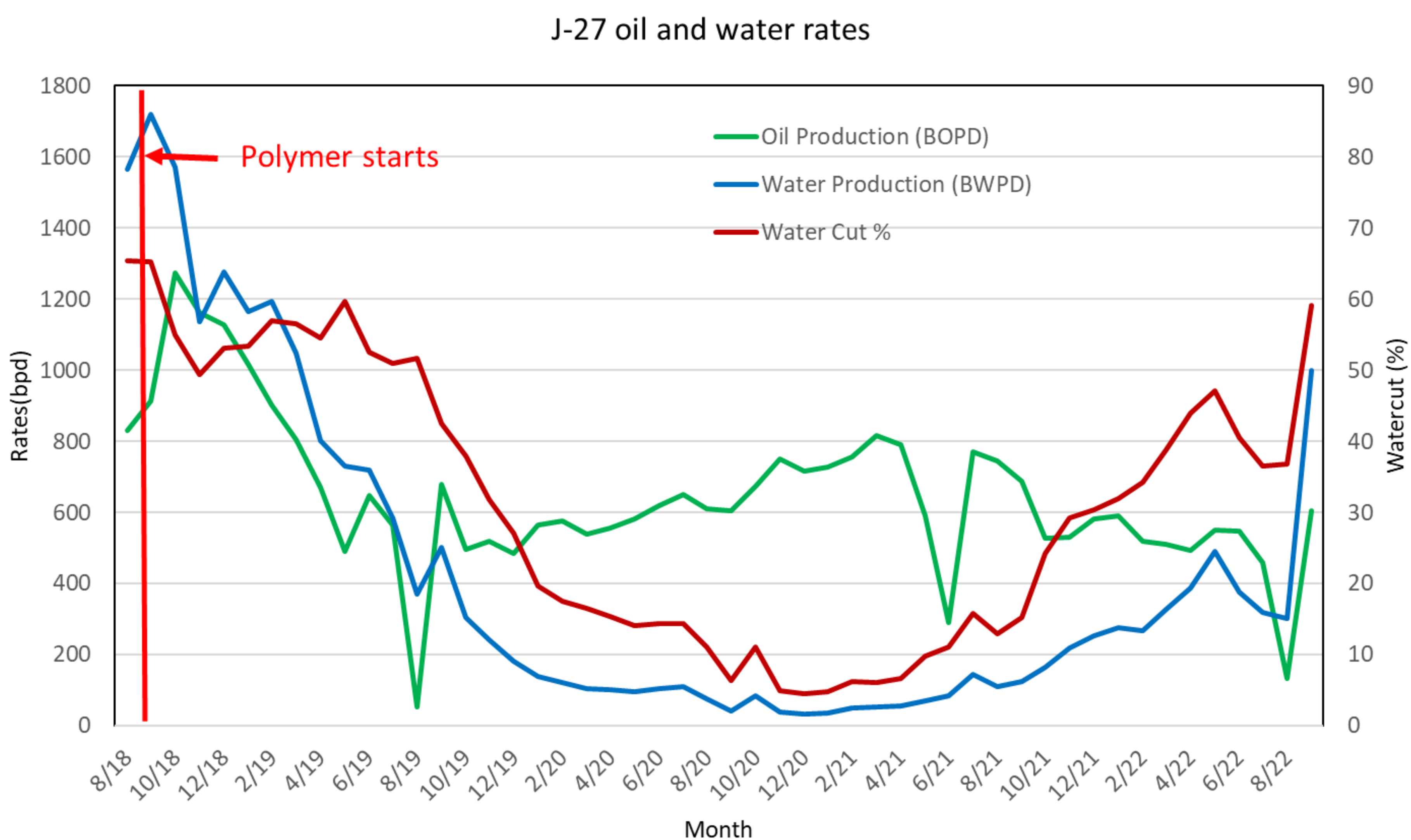


J-24A Injection Performance

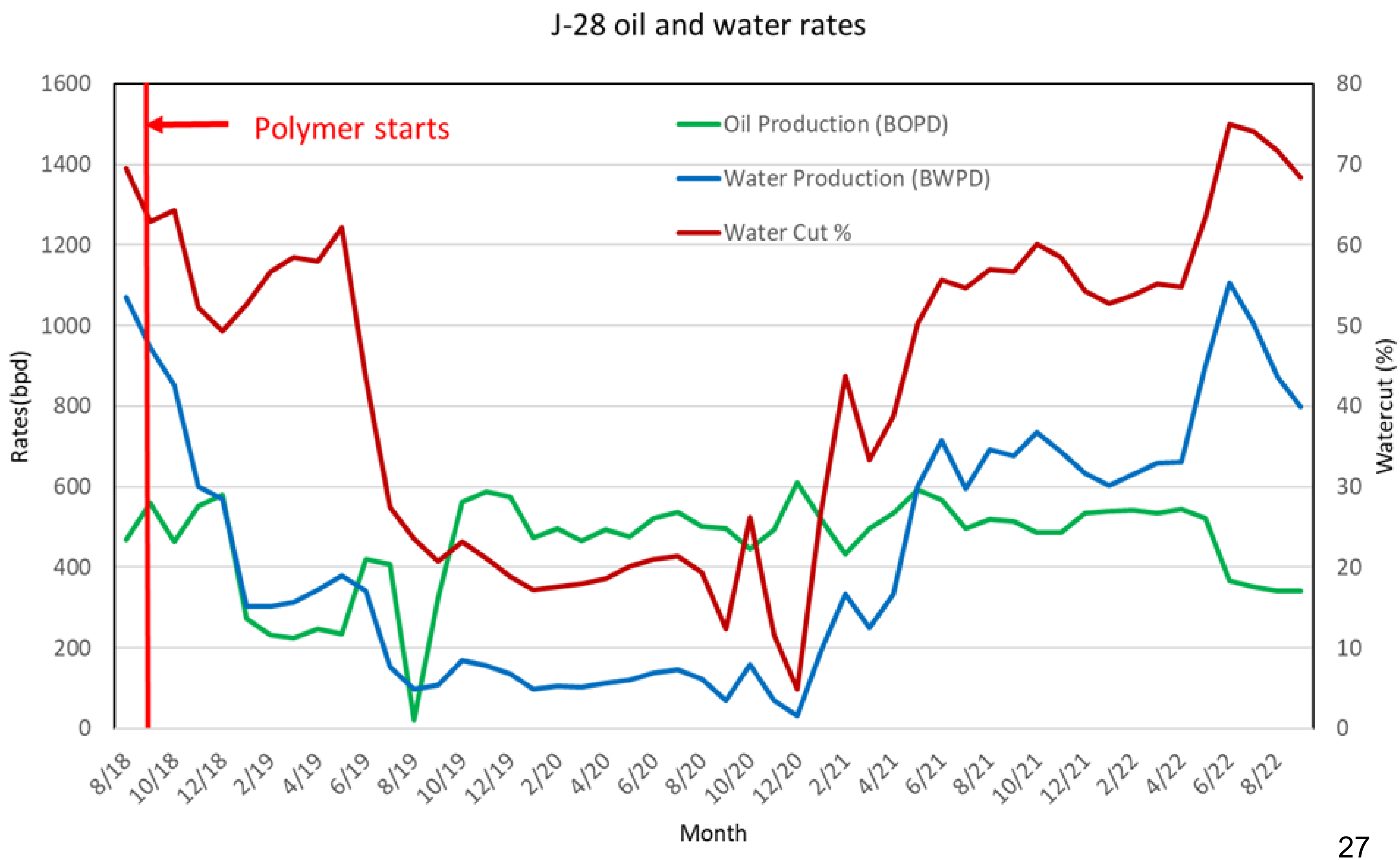
- Stable injection rate 470 bpd at 750 psi
- Cum polymer injected: 377,000 lbs



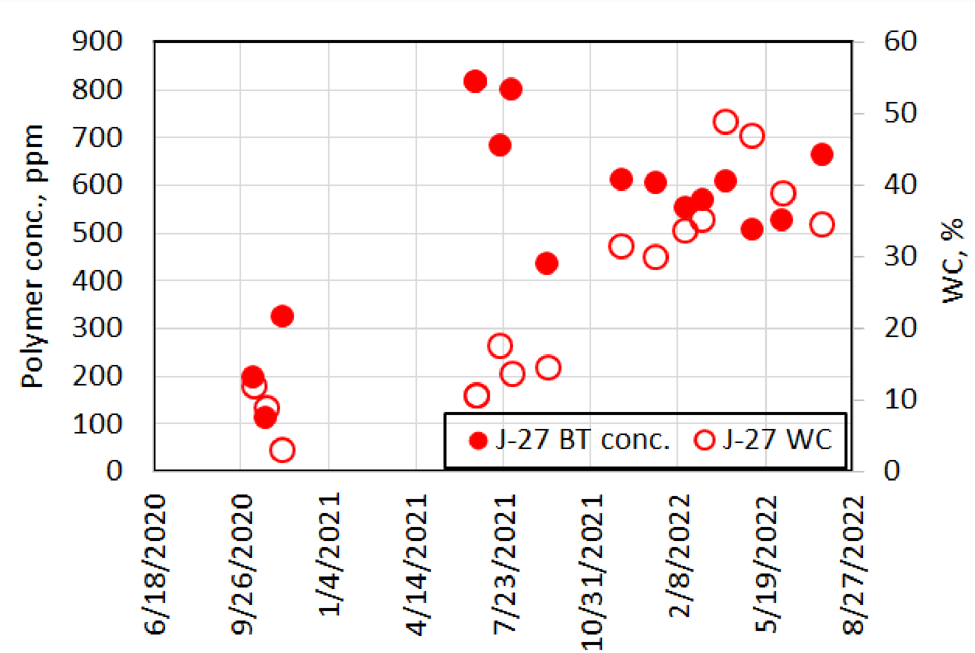
J-27 Production Performance

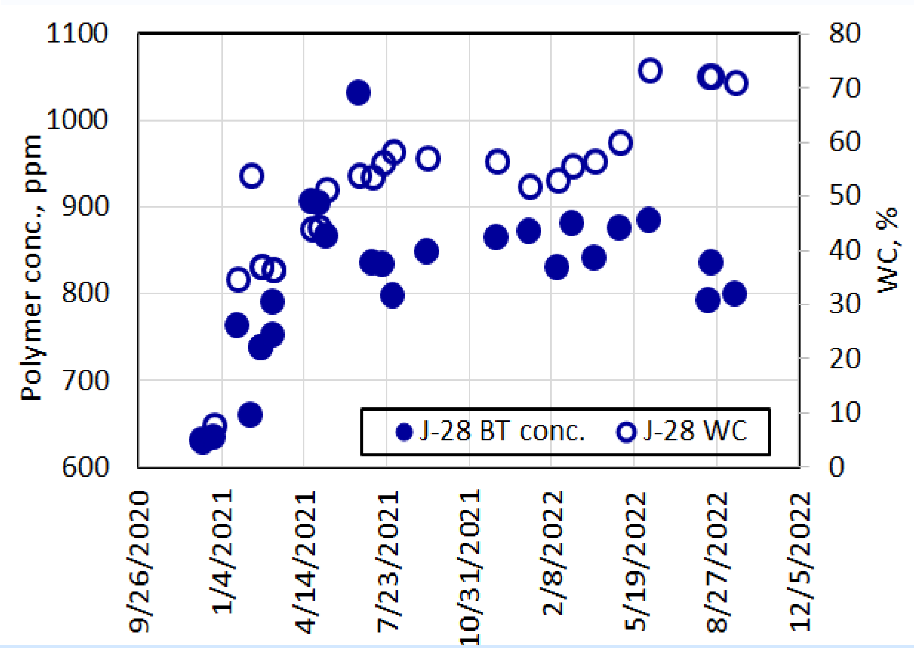


J-28 Production Performance



Tracking Polymer BT and WC

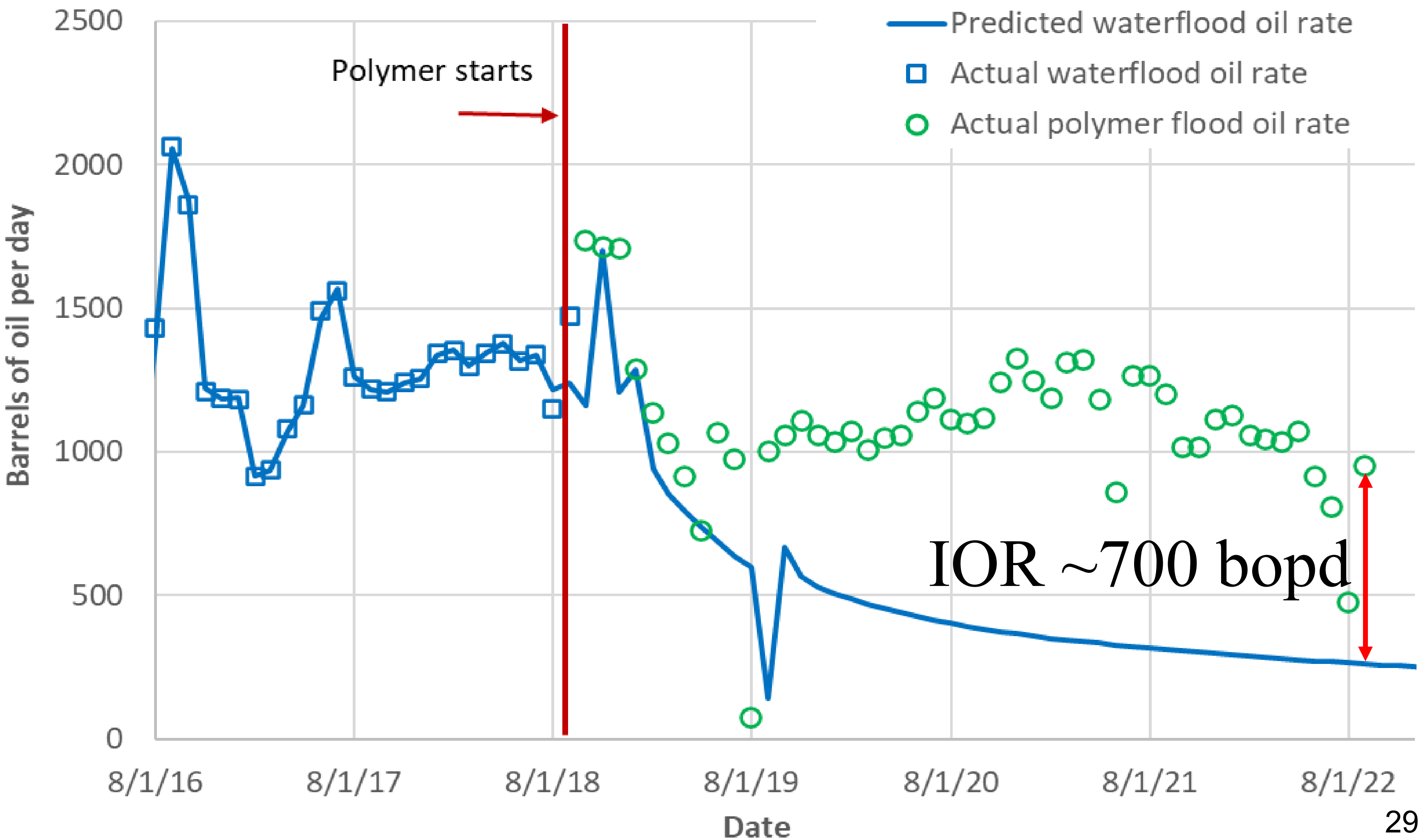




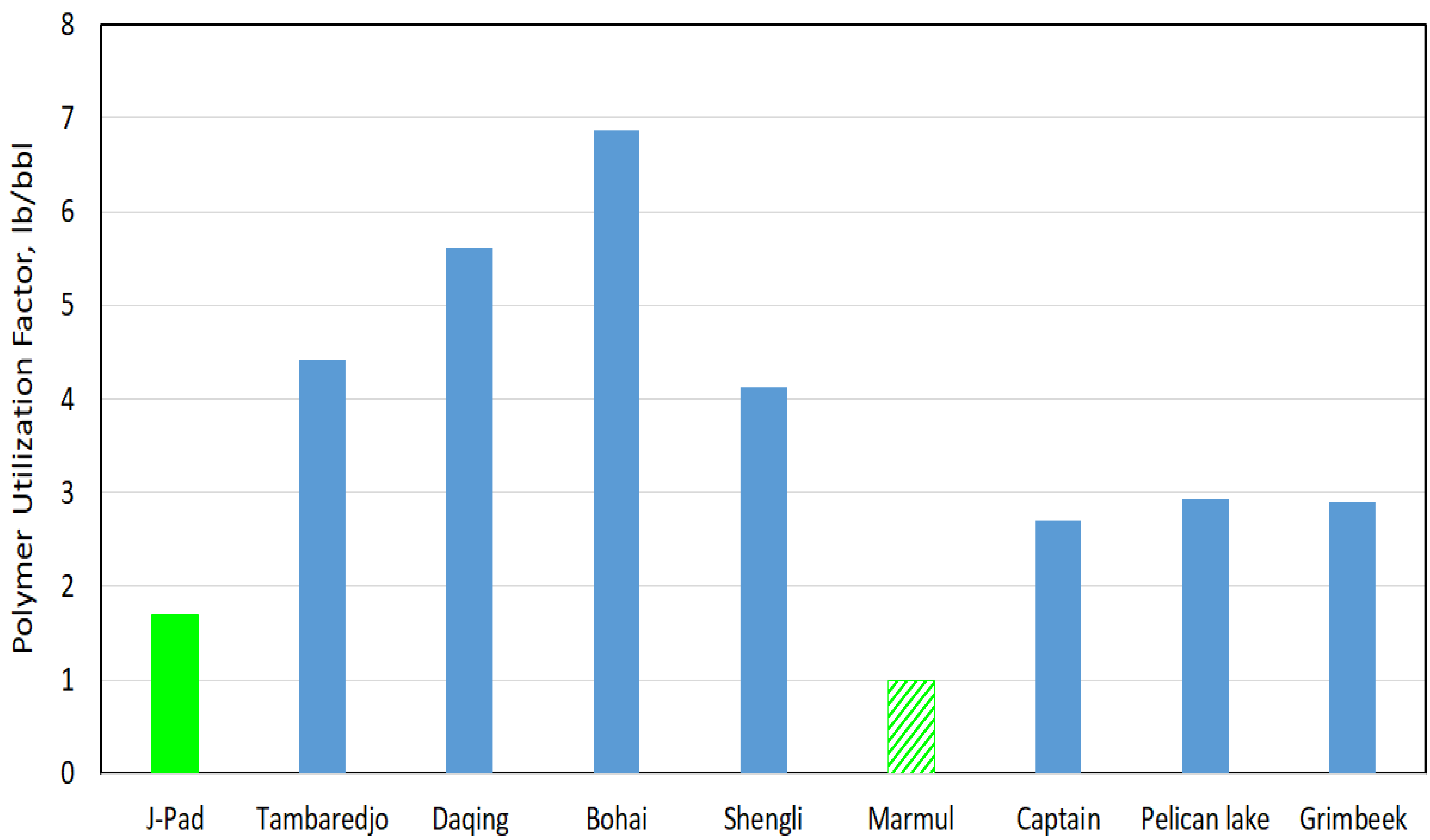
- Polymer BT time is ~ 26-28 months.
- Fairly stable polymer concentration and WC relationship in J-28.

ANSFL EOR benefit

Cum IOR = 832 mbbl; Polymer utilization = 1.7 lb/bbl

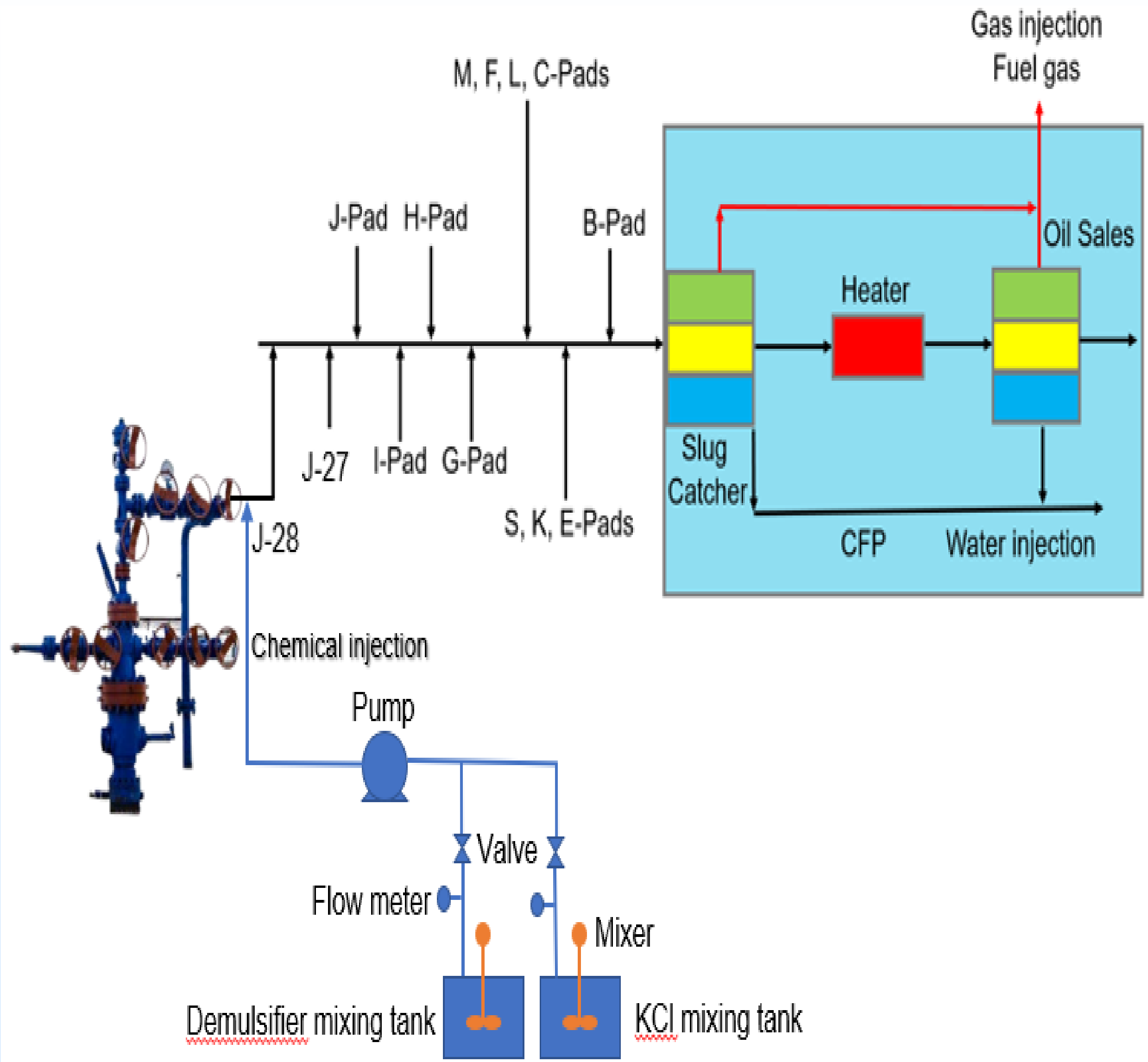


ANSFL Polymer utilization compared to others



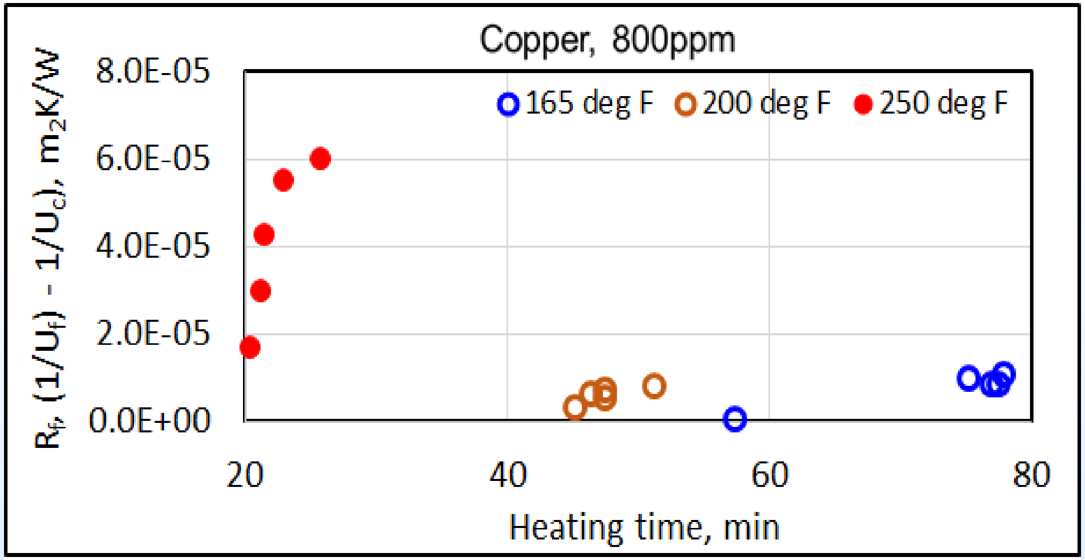
Bar chart made from Dongmei's collected data

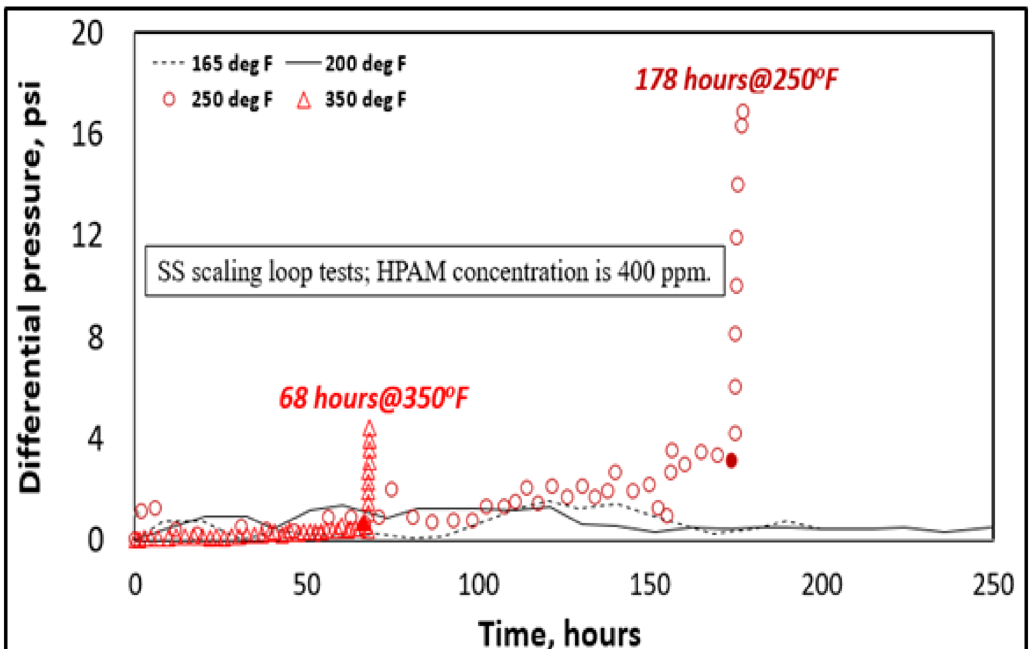
Handling of Produced Fluids



- Two major produced polymer concerns – (1) influence on emulsions and (2) heater tube fouling.
- Both addressed in Task 6.0.
- Performance criteria based on BS&W, separation efficiency and speed indicate superiority of compound (E12+E18) emulsion breakers optimized by KCl.
- Static and dynamic fouling tests provide clear operational guidelines.

Heater-Treater Skin Temperature



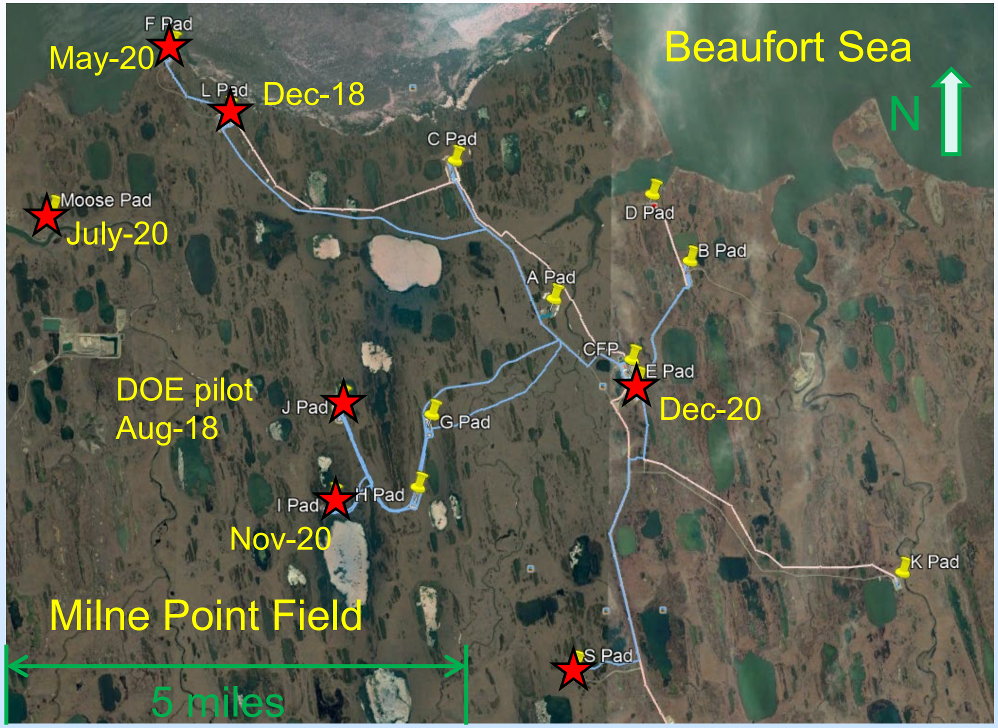


- HPAM hydrolyzes at high temperatures, and precipitates with divalent cations.
- This causes heater-treaters to foul when polymer is produced if the skin temperature is too high.
- With normal throughput rates in heater-treaters at Milne Point, this problem can be avoided by keeping the skin temperature < 250°F.
- Chevron recently reported that a skin temperature up to 325°F can be used if the polymer contains 25% AMPS.
- Deposit thicknesses for SS at 250° and 350°F have been estimated, which indicate a fairly high fouling factor.

Building on ANSFL Success – Impact and Future Directions

Polymer flood expanded:

- 7 drilling pads
- 32 injectors
- 37 mbd polymer solution
- SB Oa and Nb sands
- μ_o = 40–1,300 cP



Next target is Ugnu using PAS

Intellectual Contributions and Workforce Development

- ✓ Publications are the hallmark of the success of this team effort with **12** peer reviewed journal articles and **18** conference papers on diverse technical aspects of the polymer pilot.
- ✓ **7 MS and PhD theses**. Graduate students are first authors (and presenters) in most publications.
- ✓ **5** press releases (media) associated with the project.
- ✓ Project continues to be a strong outreach tool in a variety of avenues.
- ✓ Heavy Oil Polymer EOR in the Challenging Alaskan Arctic - It Works! A paper presented at the 2021 URTeC (paper # 5077) selected as "The Best of URTeC" for a special session in April 2022 Tulsa IOR meeting.
- ✓ The DOE NETL Federal Project Manager nominated the Alaska North Slope polymer flood project for Special Meritorious Awards for Engineering Innovation (MEA).
- ✓ ANSFL is an excellent example of "effective" collaboration between the federal government, industry and academia.

ANSFL Star – PETE MS Student Cody Keith

First place winner in the Western North America Region (April 2022) **AND** Internationally (October 2022)

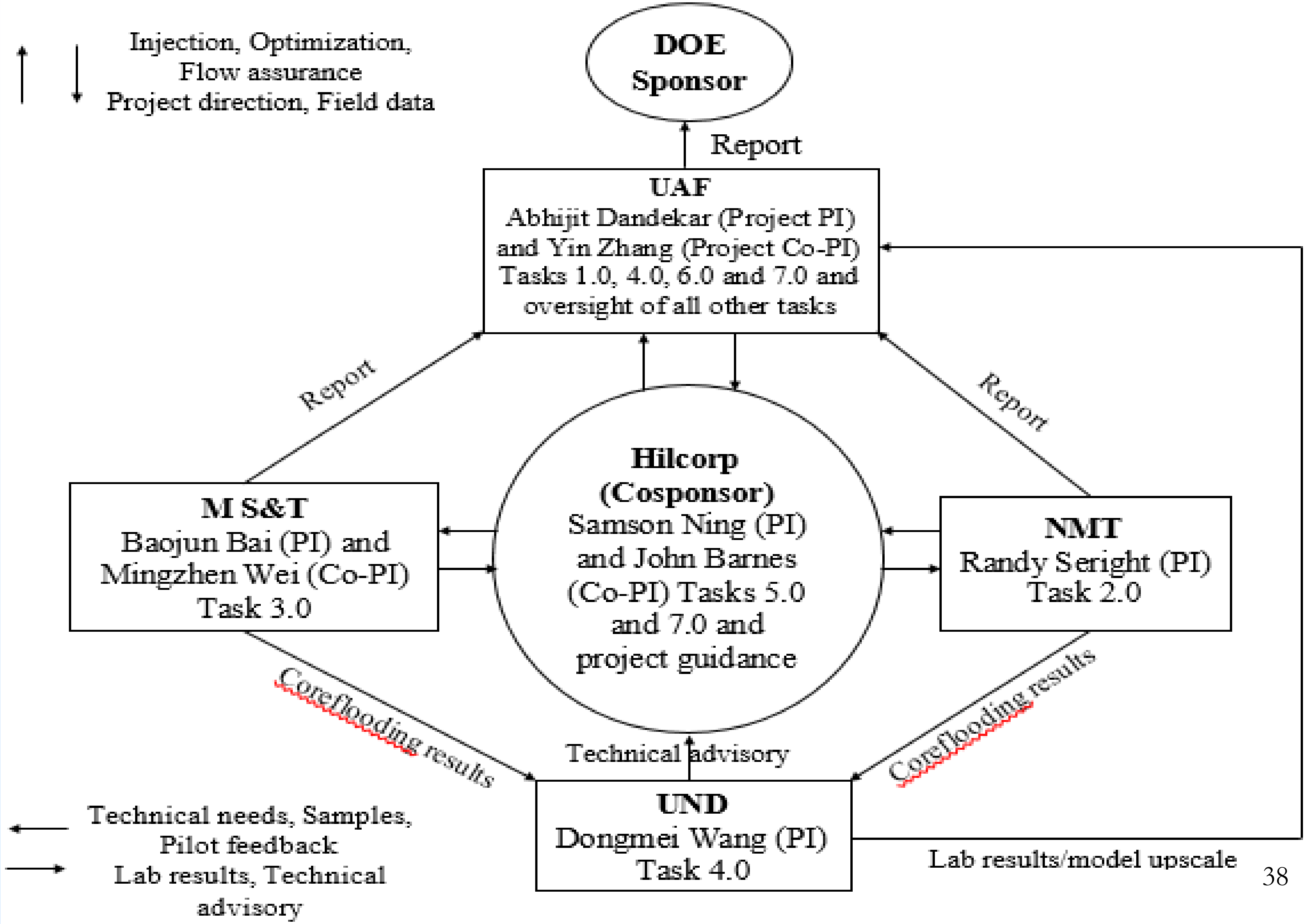
Project Summary

- ✓ As a team we learned a lot about all technical as well as economic aspects related to a field scale polymer flood – such as polymer QC, polymer facilities, polymer retention, polymer injectivity, polymer utilization factor and also the impact on downstream facilities.
- ✓ QC is more important for polymer flooding compared to standard oilfield practices.
- ✓ This project is deemed as a scientific, technical and economic success, having met all objectives, fulfilled deliverables and within budget.
- ✓ First and foremost **Heavy Oil Polymer EOR in the Challenging Alaskan Arctic - It Works!**

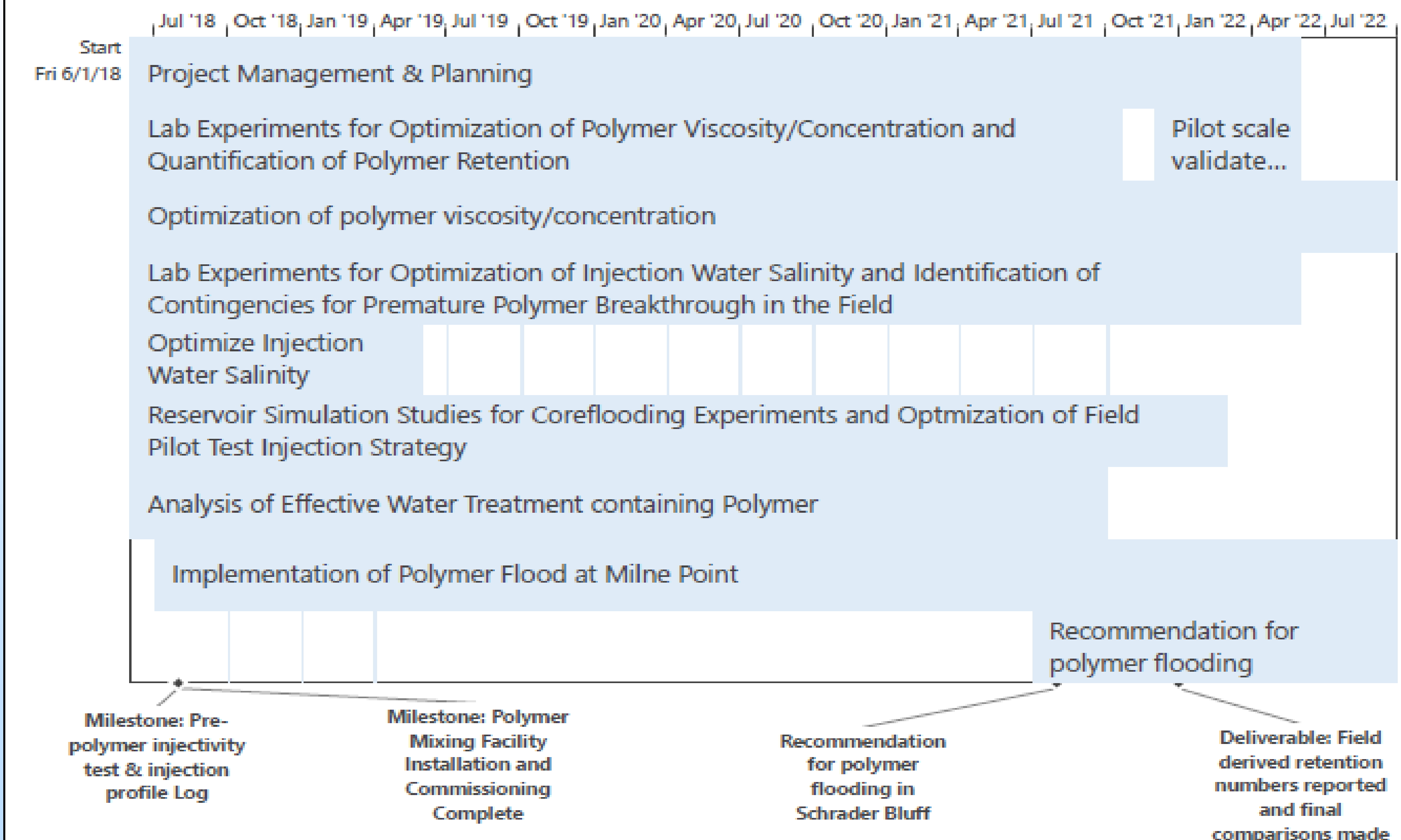
Appendix

– These slides will not be discussed during the presentation but are mandatory.

Organization Chart



Gantt Chart



Jul '18
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Apr '21
Jul '21
Oct '21
Jan '22
Apr '22
Jul '22
Start
Fri 6/1/18
Finish
Fri 9/30/22
Project Management & Planning
Lab Experiments for Optimization of Polymer Viscosity/Concentration and Quantification of Polymer Retention
Pilot scale validate...
Optimization of polymer viscosity/concentration
Lab Experiments for Optimization of Injection Water Salinity and Identification of Contingencies for Premature Polymer Breakthrough in the Field
Optimize Injection Water Salinity
Reservoir Simulation Studies for Coreflooding Experiments and Optmization of Field Pilot Test Injection Strategy
Analysis of Effective Water Treatment containing Polymer
Implementation of Polymer Flood at Milne Point
Recommendation for polymer flooding
Milestone: Pre-polymer injectivity test & injection profile Log
Milestone: Polymer Mixing Facility Installation and Commissioning Complete
Recommendation for polymer flooding in Schrader Bluff
Deliverable: Field derived retention numbers reported and final comparisons made

Acknowledgements

Thanks to US DOE, NETL, Hilcorp Alaska LLC
Milne Point operators, and all researchers for DOE project
Award Number DE-FE0031606

U.S. DEPARTMENT OF ENERGY | Fossil Energy and Carbon Management

NATIONAL ENERGY TECHNOLOGY LABORATORY

Hilcorp Alaska

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