2022 GAS LIFT WORKSHOP

Presentation Title: Optimizing an unconventional field via RTPO

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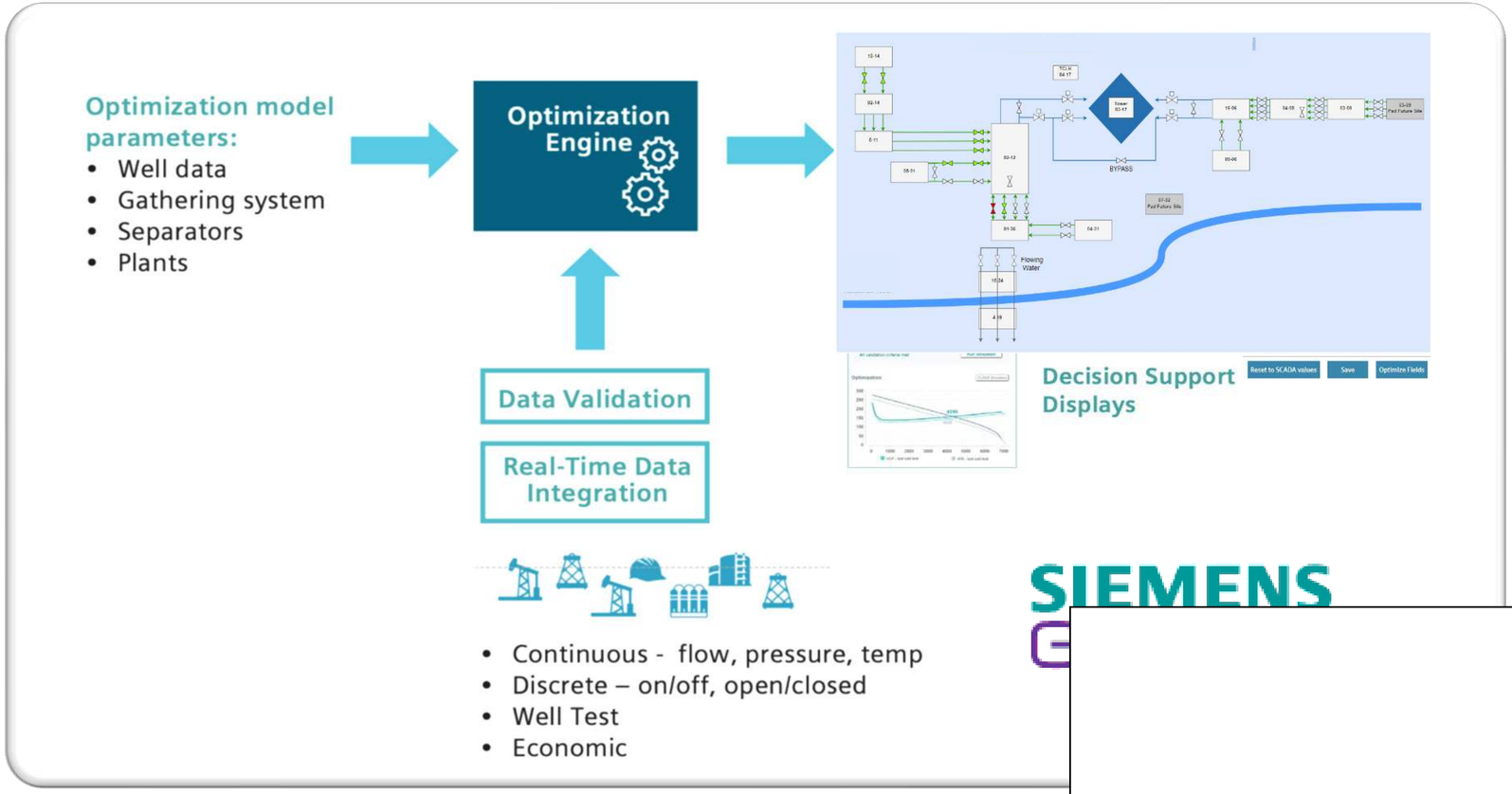
Agenda

- Field & Solution snapshot
- Workflow
- Modelling & Optimization
- Challenges
- RTPO Dashboard
- Solution value

Field and Solution Snapshot

Field
  – 181 wells (130 -150 active)
- Production
  – Condensate: 7,200 b/d
  – Gas: 180 MMscf/d
  – Water: 7,500 b/d
- Gas Lift, Natural, GAPL
- Unconventional field

Delivered [RTPO]
- Data acquisition & validation system
- Automatic model update
- Automatic daily optimization
- Dashboard for:
  – Display of optimal set points
  – Input for scenario configuration

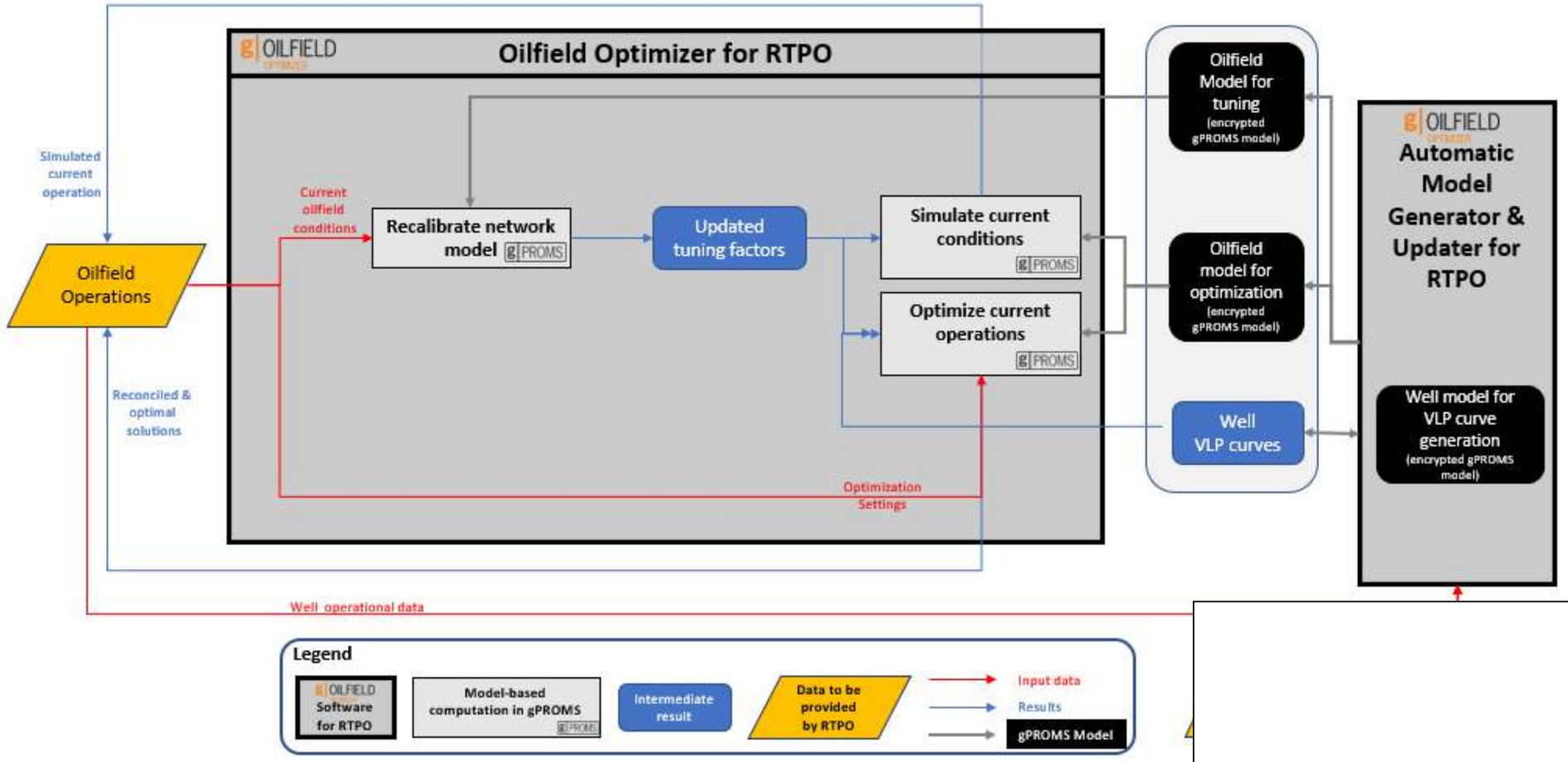


Workflow Overview

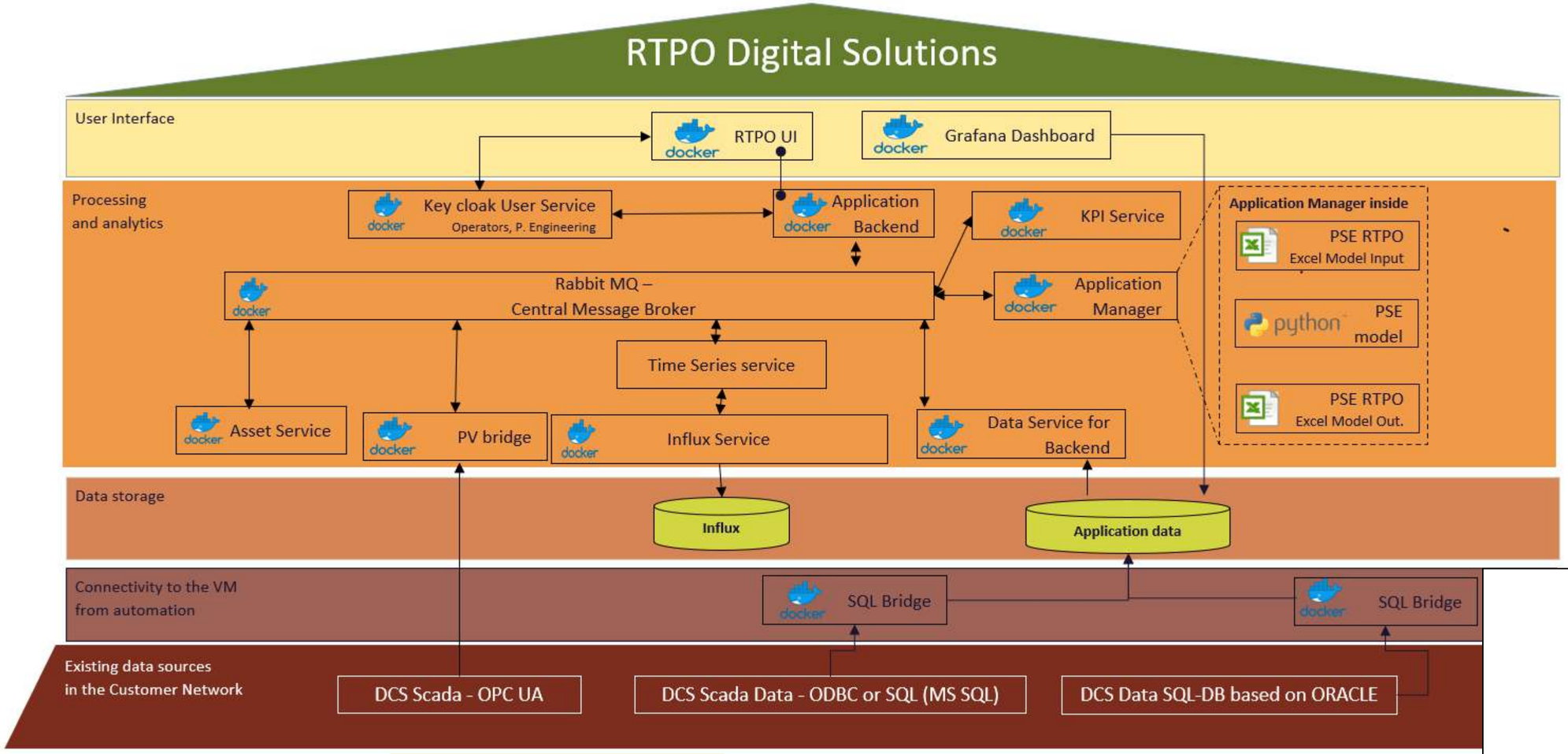
Workflow executed once a day (i.e. Midnight)

- VLP Creation
- Model Tuning
- Operating point Simulation
- Optimization

Results available in the dashboard for the morning shift



System architecture



gPROMS Process

Typical Use Cases

Snapshot Optimization
- Regular optimization to determine the best set of field setpoints

"What-if" decision support
- Plan for field changes and workover to identify the impact on production

Real-Time Field Upset
- Minimize production losses until the upset condition is fixed

Limited changes optimization
- Limiting the number of new set points generated by the optimize

Routing optimization
- Determine the optimal flow path through the system

Integrated Asset Optimization
- Ensure optimal system settings can be handled by the whole asset

Field Planning
- Optimise the field over a longer time frame taking into account reservoir decline

Key Features

- Asset Digital Twin, including production and facilities
- Self calibrating Physics-based model
- Fully equation-oriented solver
- "Globalization strategy" to avoid being trapped in local optima
- Simultaneous optimization of continuous & discrete decisions (MINLP)
- Customizable objective function and constraints
- Offline (desktop + web) and online deployment

Integrated Asset Optimization

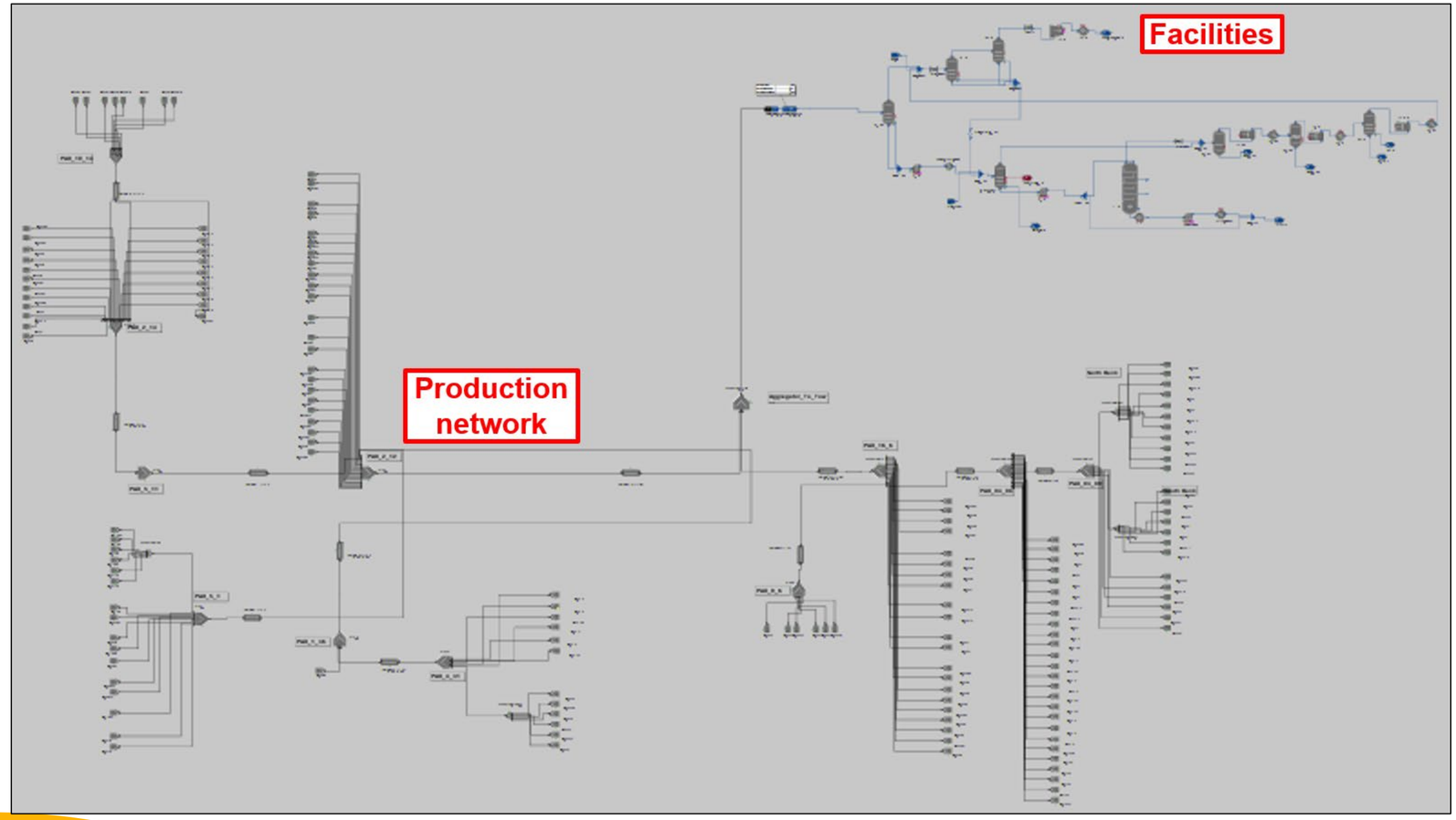
Production Network
- 181 wells (130 -150 active)
- 10 Well pads
- Separator

Facilities
- Separation
- Compression
- Condensate stabilization

Objective
- Maximize condensate

Decisions:
- Gas Lift rate
- Choke pressure drop
- Well Status
- # of parallel flowlines

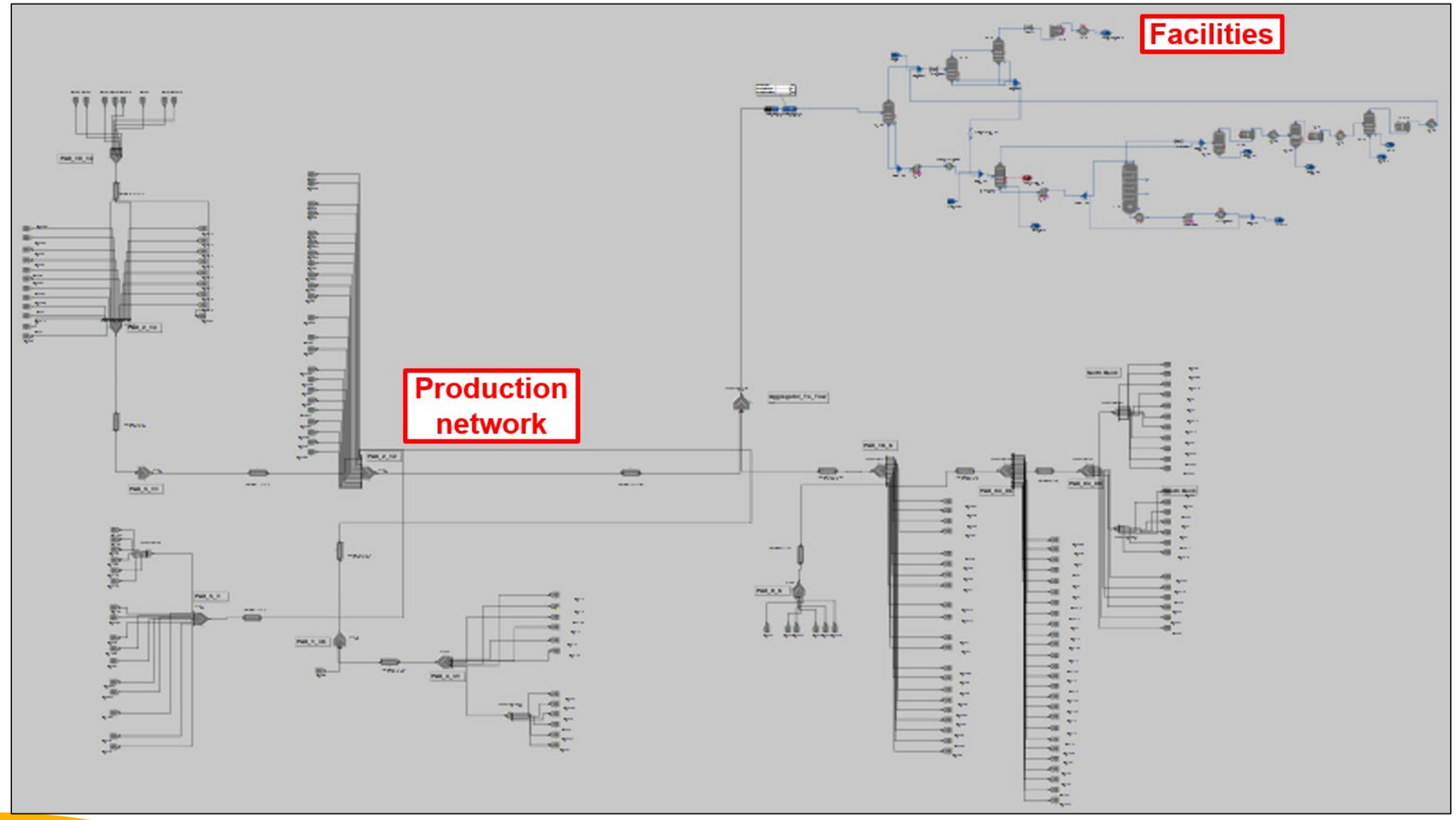
Constraints
- Max total gas lift
- Max well gas rate
- Min pipeline velocities
- Max total gas/water rates (equipment capacities)
- Max condensate RVP specification



Challenge: Update field data

gPROMS Process Model:

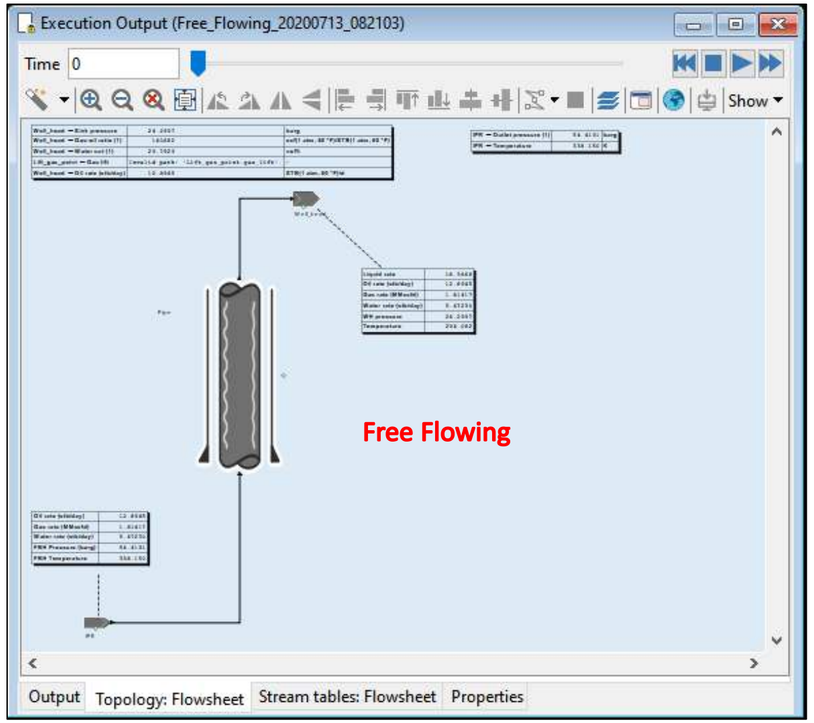
- Configured to receive all field data
- Data collected by digital solution into SQL database
- SQL database updated at the onset of each optimisation or VLP generation
- Thus, model always contains latest field data when performing an optimization

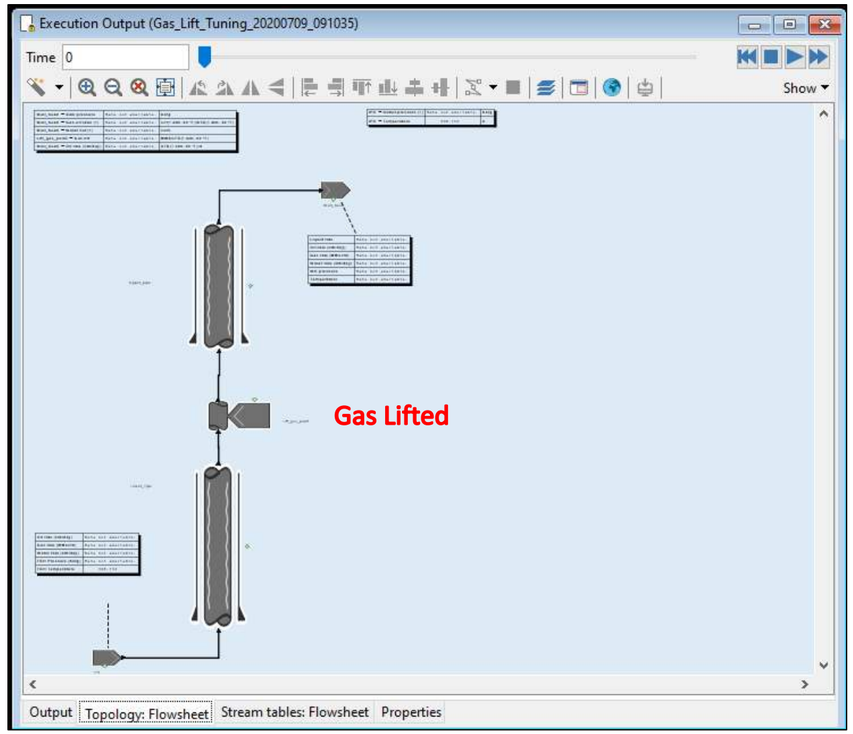


Challenge: Well Modelling – VLP Creation

For Gas lifted and Naturally flowing wells:

- gPROMS Process Model template created
- Template automatically populated with well data to model the well tubing from bottomhole to wellhead for each well
- Calibrated model to known well tubing pressure drop
  - Fitted well tubing pressure drop parameters to match field bottomhole pressure
- Produced well bore performance curves (VLP) via Global Sensitivity Analysis (multi-core module)





Challenge: Data Validation

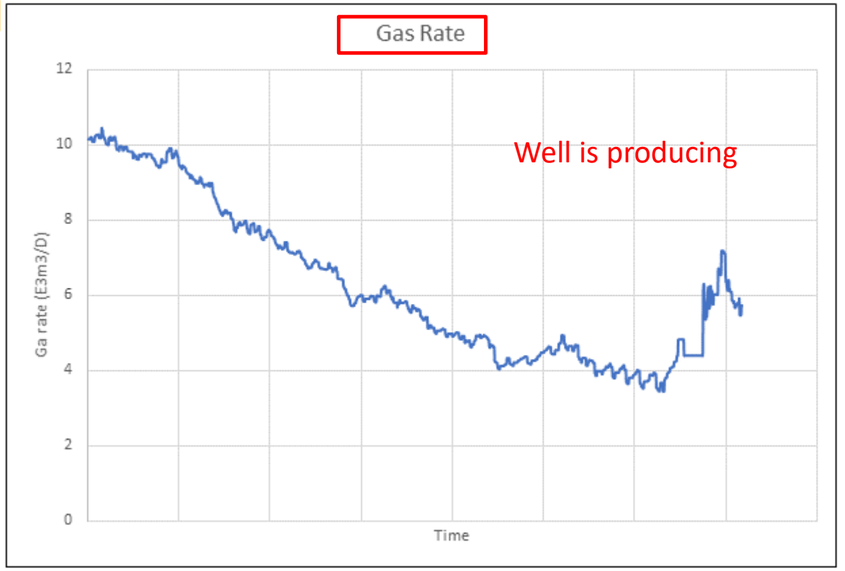
Data from instrumentation can be “problematic”

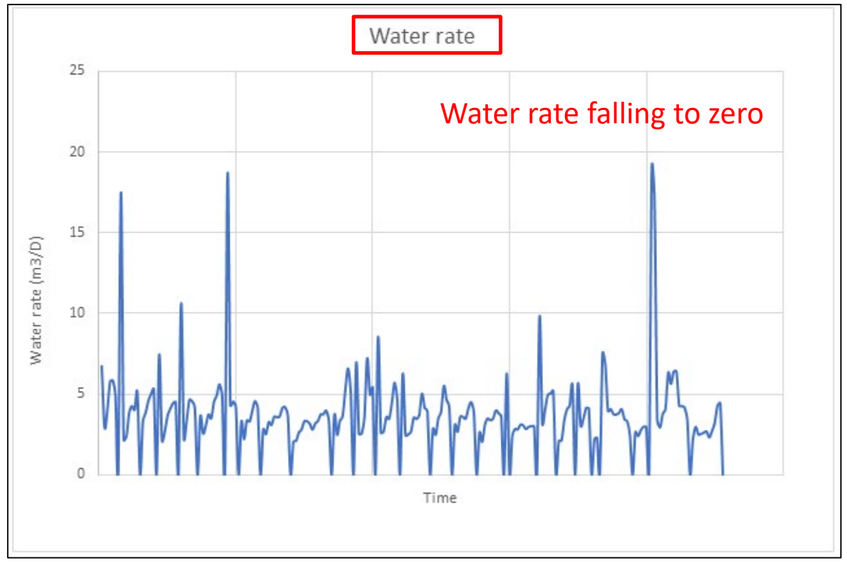
- Out of range data ,i.e. negative water cut, etc.
- Within valid range but non-sensical, i.e. zero rates (see plots)

Any online solution needs to be robust enough to handle these conditions

To avoid faulty measurements causing process model calculation errors:

- Sensible min and max values were set for all input data
- Logic was defined for action to be taken when data bounds were violated
- All data values were screened and logic followed before sending data to the model





Challenge: Data Validation

Tag

Boundaries

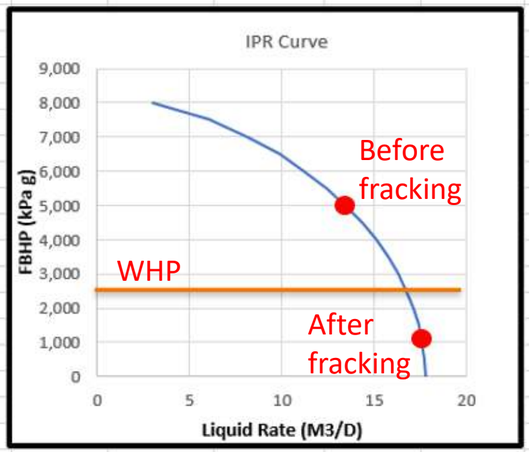
Rules-logic

	A	B	C	D	E	F	G	H	I	J	K	L	M
1	Excel Sheet		Tag		Min Value	Max Value	Units	Rule / Math for under Min	Rule / Math for over Max	Averaging?	Avg. Timeframe		
2	**Current Operation**	**Production**											
3	Current Operation	Production	Liquid Rate		0	200	m3/d	shut-in well	report			Operating values: 2 - 55	
4	Current Operation	Production	Oil Rate		0	100	m3/d	shut-in well	report			Operating values: 0.6 - 36	
5	Current Operation	Production	Water Rate		0	200	m3/d	shut-in well	report			Operating values: 0.4 - 65	
6	Current Operation	Production	Gas Rate		0	300	e3m3/d	shut-in well	report			Operating values: 10 - 190	
7	Current Operation	Production	FWHP		1800	6200	kpa g	report	report			Operating values: 2000 - 5920	
8	Current Operation	Production	FWHT		0	60	C	set = average FWHT	set = average FWHT			Operating values: -4 - 40	
9	*Current Operation*	*Production*	*FBHP*				*kPa g*						
10	Current Operation	Production	Gas Lift Injection rate		0	40	e3m3/d	set = 0	report			Operating values: 0 - 20	
11	Current Operation	Production	WH Choke DP		0	4000	kpa	set = 0	report			Operating values: 0 - 3900	
12	Current Operation	Production	WH Choke opening		0	100	%	0	100				
13	Current Operation	Production	PAD pressure		2000	3500	kPa g	report	report			Operating values: 2200 - 2850	
14	Current Operation	Separator Contrains	Pressure		2000	2300	kPa g	Error: stop & report	Error: stop & report				
15	**Current Fluid Analysis**	**Process conditions**											
16	Current Fluid Analysis	Process conditions	Pressure		1900	4000	kPa g	set = average Pressure	set = average Pressure			Operating values: 2000 - 3900	
17	Current Fluid Analysis	Process conditions	Temperature		0	50	C	set = average Temperatue	set = average Temperatue			Operating values: 1 - 42	
18	Current Fluid Analysis	Process conditions	OGR		0	0,002	m3/m3	set = average OCR	set = average OCR			Operating values: 1E-5 to 1E-3	
19	**Optimization**	**Tab**											
20	Optimization	WELL HEAD CHOKE	Keep fixed at		0	10000	kPa	set = 0	report				
21	Optimization	WELL HEAD CHOKE	No less than		0	no more than	kPa	set = 0	set = no more than				
22	Optimization	WELL HEAD CHOKE	No more than		No less than	10000	kPa	set = no less than	report				
23	Optimization	Gas Lift	Keep fixed at		0	40	e3m3/d	set = 0	report				
24	Optimization	Gas Lift	No less than		0	no more than	e3m3/d	set = 0	set = no more than				
25	Optimization	Gas Lift	No more than		No less than	40	e3m3/d	set = no less than	report				
26	Optimization	Production Constrains	Maximum Total Gas Rate		80	400	e3m3/d	set = current total gas rate	report			Operating values: 80 - 303	must be > than current total g
27	Optimization	Production Constrains	Maximum Mixture Velocity		5	200	m/s	report	report				
28	Optimization	Production Constrains	Minimum FBHP		2200	12000	kPa g	report	report				
29	Optimization	Pipeline Contrains	Max Velocity		18,3	18,3	m/s						
30	Optimization	Pipeline Contrains	Min Velocity		4,572	4,572	m/s						
31	Optimization	Separator Contrains	Pressure		2000	2300	kPa g	Error: stop & report	Error: stop & report				
32	Optimization	Separator Contrains	Maximum Liquid Rate		0	5000	m3/d	Error: stop & report	report				
33	Optimization	Separator Contrains	Maximum Gas Rate		0	10000	e3m3/d	Error: stop & report	report				
34	Optimization	Separator Contrains	Maximum Water Rate		0	5000	m3/d	Error: stop & report	report				
35	Optimization	Field settings	Optimize routing										
36	Optimization	Field settings	Maximum Liquid rate		0	5000	m3/d	Error: stop & report	report				
37	Optimization	Field settings	Maximum Gas Rate		0	10000	e3m3/d	Error: stop & report	report				
38	Optimization	Field settings	Maximum Oil rate		0	5000	m3/d	Error: stop & report	report				

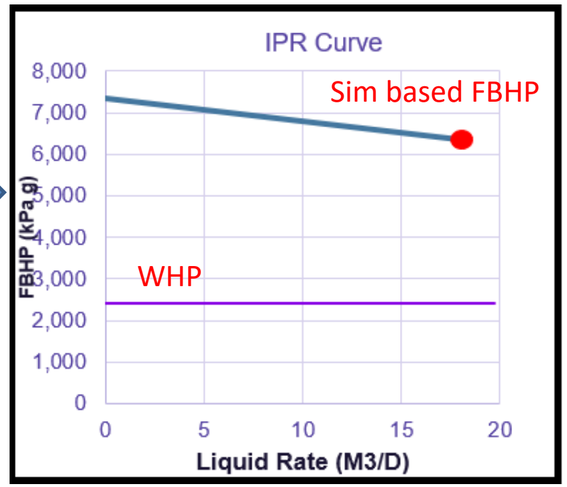
Challenge: IPR Curves

- IPR curve data provided by customer
- Nearby well fracturing caused increase in liquid rate, for which IPR gives FBHP < WHP
- Solution: IPR curves were checked daily and adjusted, where necessary, based on FBHP obtained from the well simulation

IPR Table	
Liquid Rate	FBHP
M3/D	kPa g
2.98	8,000
6.05	7,500
8.16	7,000
9.83	6,500
11.23	6,000
12.42	5,500
13.44	5,000
14.33	4,500
15.09	4,000
15.74	3,500
16.29	3,000
16.74	2,500
17.11	2,000
17.39	1,500
17.59	1,000
17.71	500
17.75	0

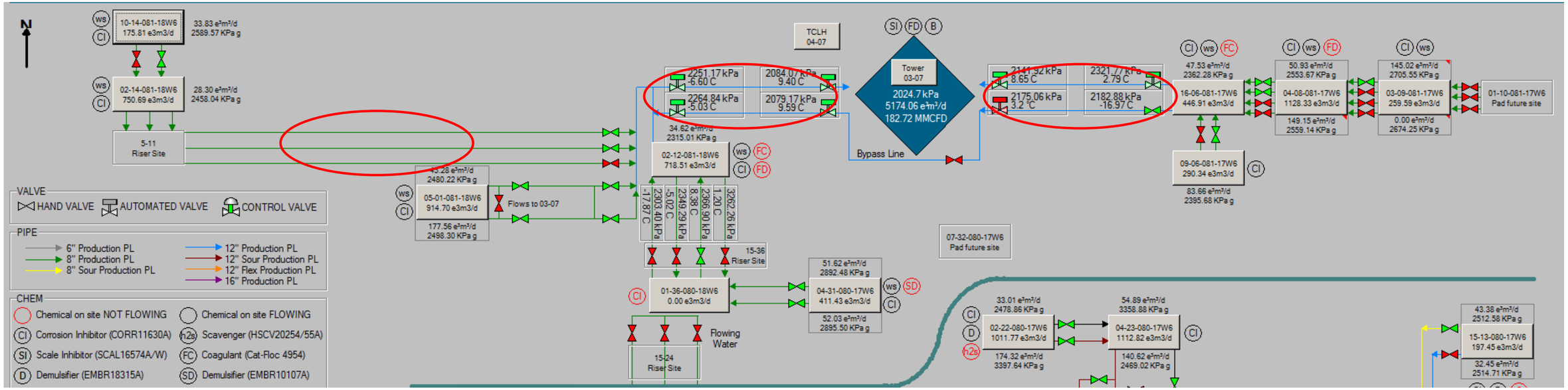


used 30497
2.882838 adjusted

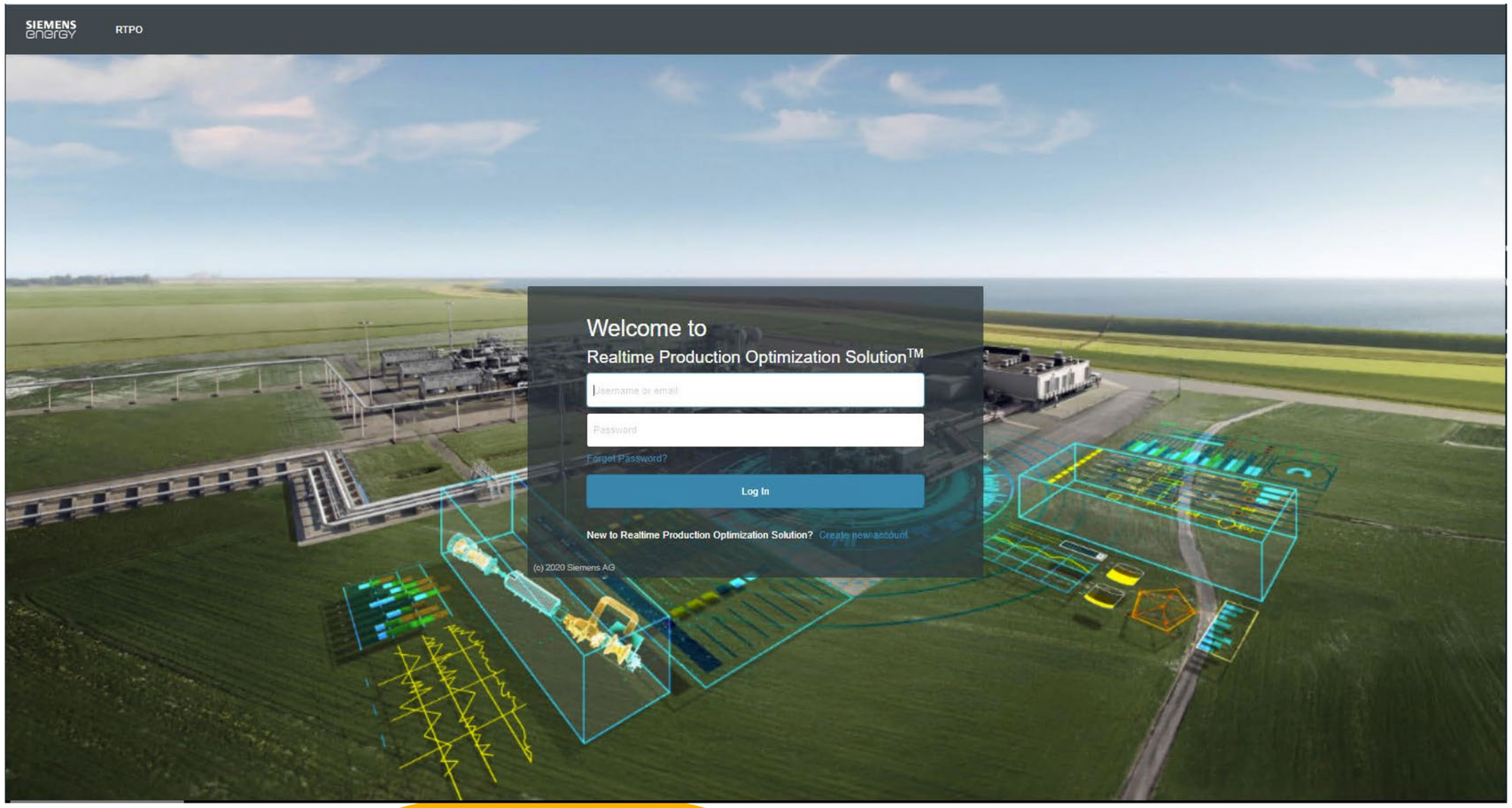


Challenge: Velocities

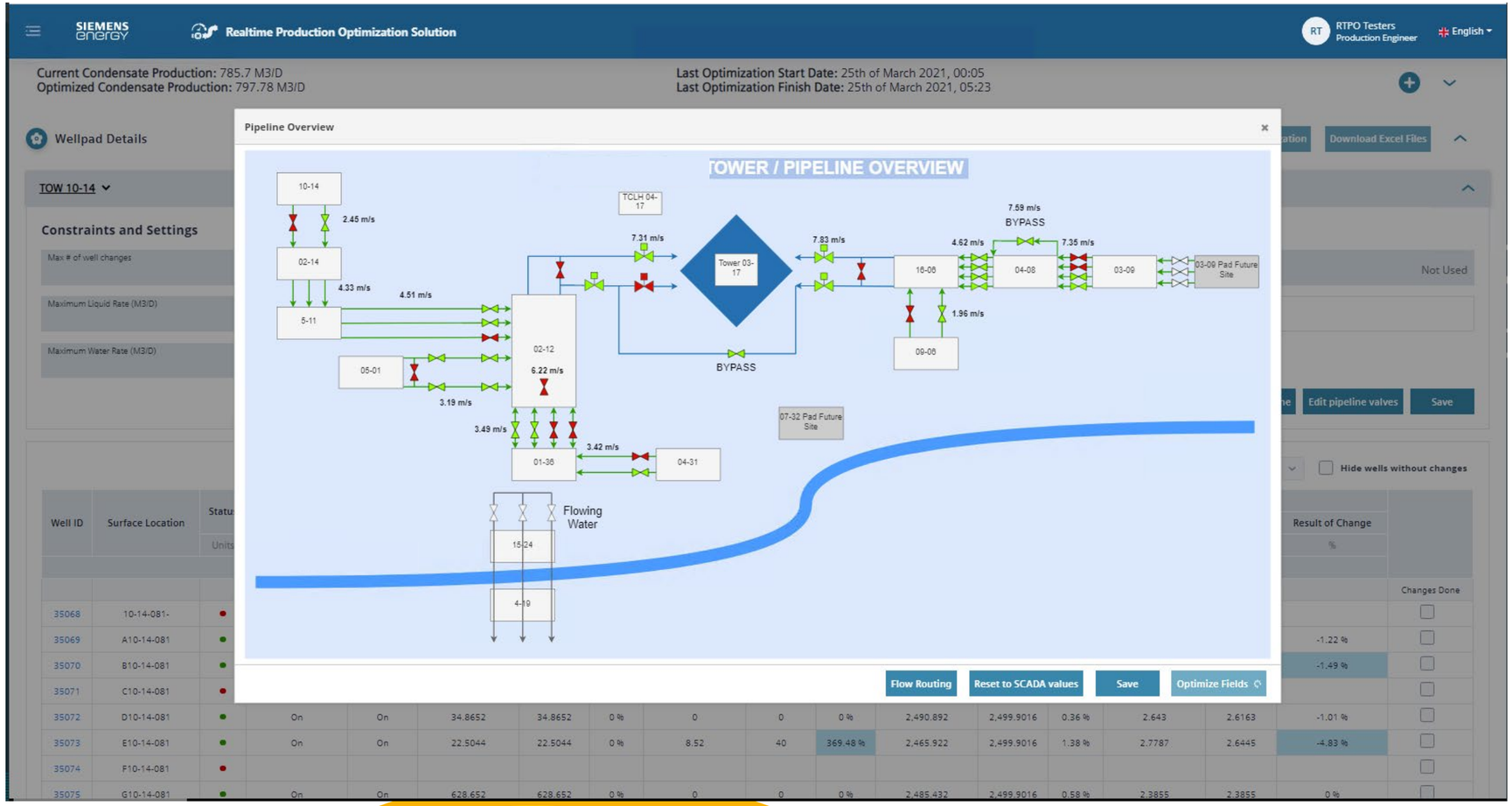
- Field needed minimum velocity in key pipelines to avoid slugging
- Solution: # of parallel pipelines for all flowlines was included as a decision variable. If constraint violated, then 1 or more pipelines were closed.



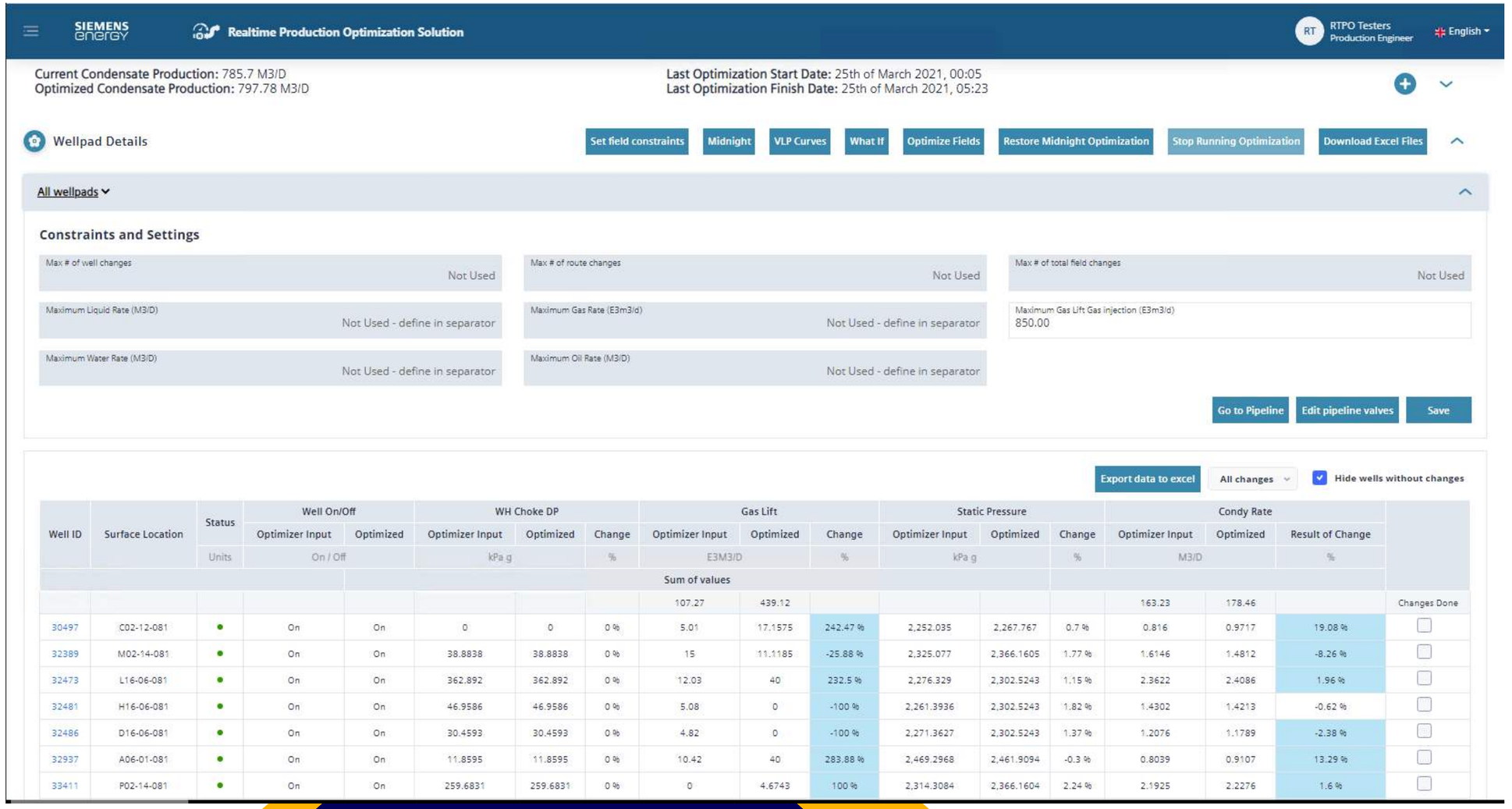
RTPO Dashboard – Login page



RTPO Dashboard – Real-time Schematic

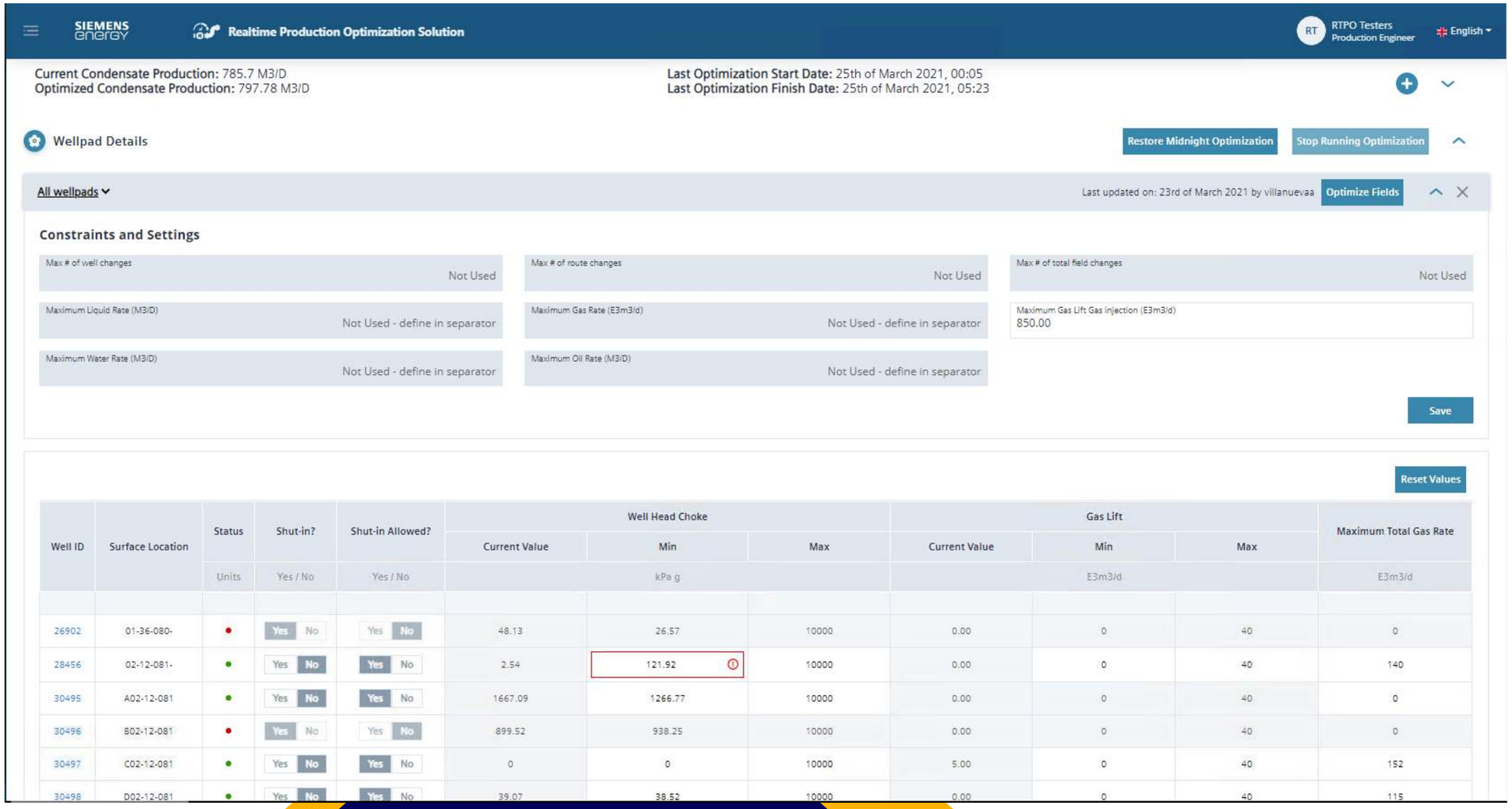


RTPO Dashboard – Daily Optimization Results

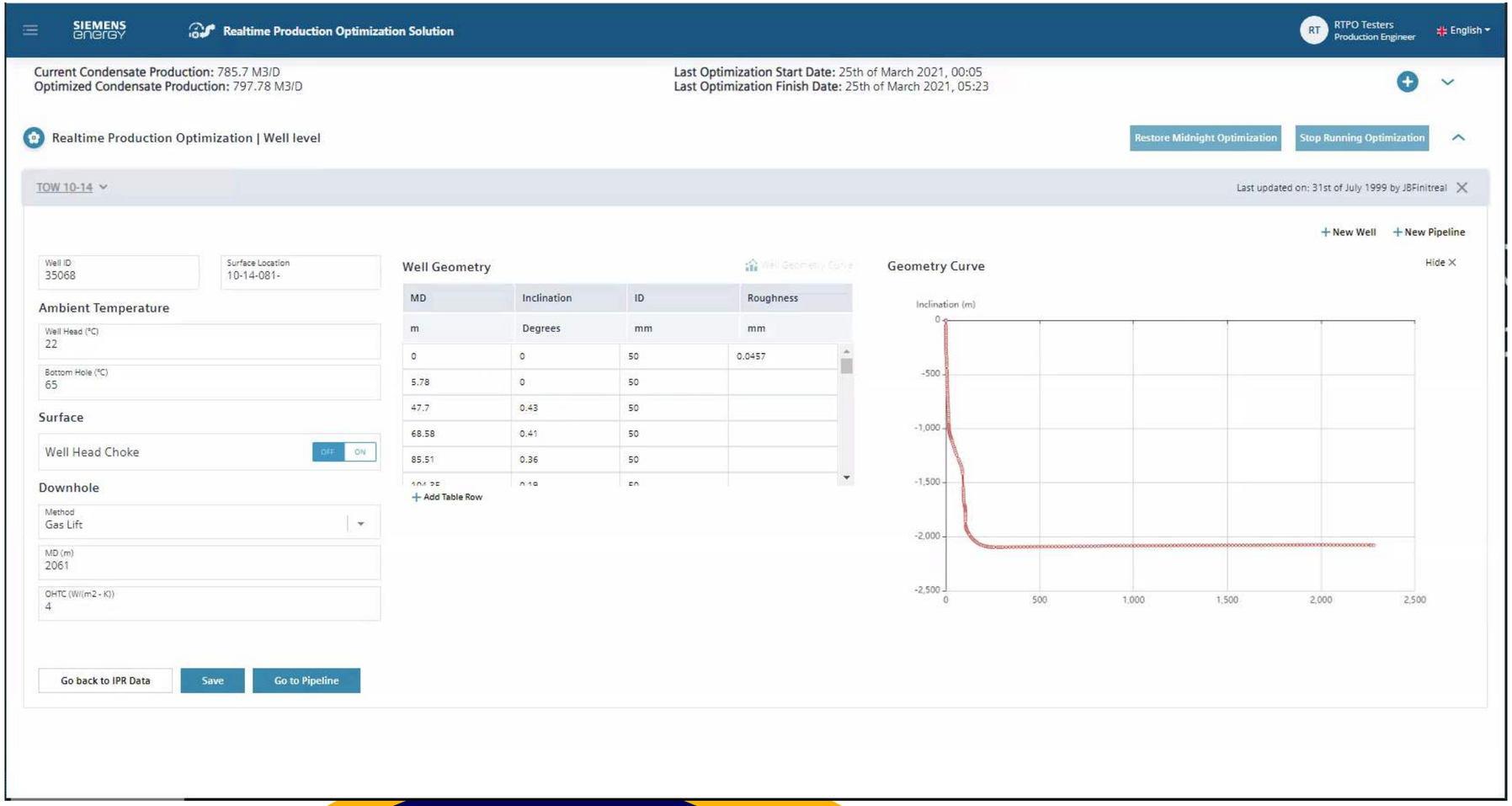


Well ID	Surface Location	Status	Well On/Off		WH Choke DP			Gas Lift			Static Pressure			Condy Rate			
			Optimizer Input	Optimized	Optimizer Input	Optimized	Change	Optimizer Input	Optimized	Change	Optimizer Input	Optimized	Change	Optimizer Input	Optimized	Result of Change	
		Units	On / Off		kPa g		%	E3M3/D		%	kPa g		%	M3/D		%	
			Sum of values					107.27	439.12					163.23	178.46		Changes Done
30497	C02-12-081	●	On	On	0	0	0 %	5.01	17.1575	242.47 %	2,252.035	2,267.767	0.7 %	0.816	0.9717	19.08 %	
32389	M02-14-081	●	On	On	38.8838	38.8838	0 %	15	11.1185	-25.88 %	2,325.077	2,366.1605	1.77 %	1.6146	1.4812	-8.26 %	
32473	L16-06-081	●	On	On	362.892	362.892	0 %	12.03	40	232.5 %	2,276.329	2,302.5243	1.15 %	2.3622	2.4086	1.96 %	
32481	H16-06-081	●	On	On	46.9586	46.9586	0 %	5.08	0	-100 %	2,261.3936	2,302.5243	1.82 %	1.4302	1.4213	-0.62 %	
32486	D16-06-081	●	On	On	30.4593	30.4593	0 %	4.82	0	-100 %	2,271.3627	2,302.5243	1.37 %	1.2076	1.1789	-2.38 %	
32937	A06-01-081	●	On	On	11.8595	11.8595	0 %	10.42	40	283.88 %	2,469.2968	2,461.9094	-0.3 %	0.8039	0.9107	13.29 %	
33411	P02-14-081	●	On	On	259.6831	259.6831	0 %	0	4.6743	100 %	2,314.3084	2,366.1604	2.24 %	2.1925	2.2276	1.6 %	

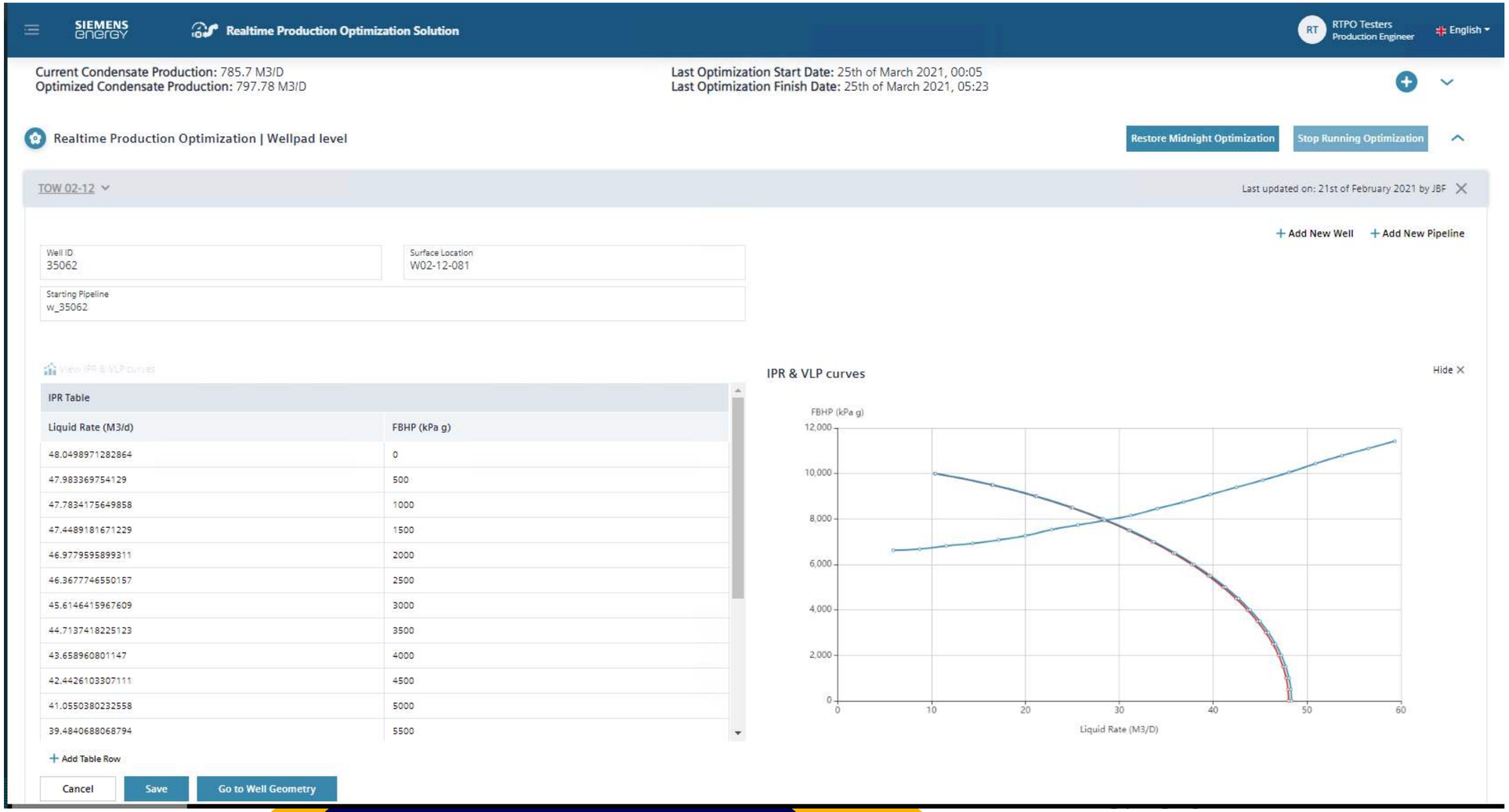
RTPO Dashboard – What-if Optimization settings



RTPO Dashboard – Well Settings/Inputs



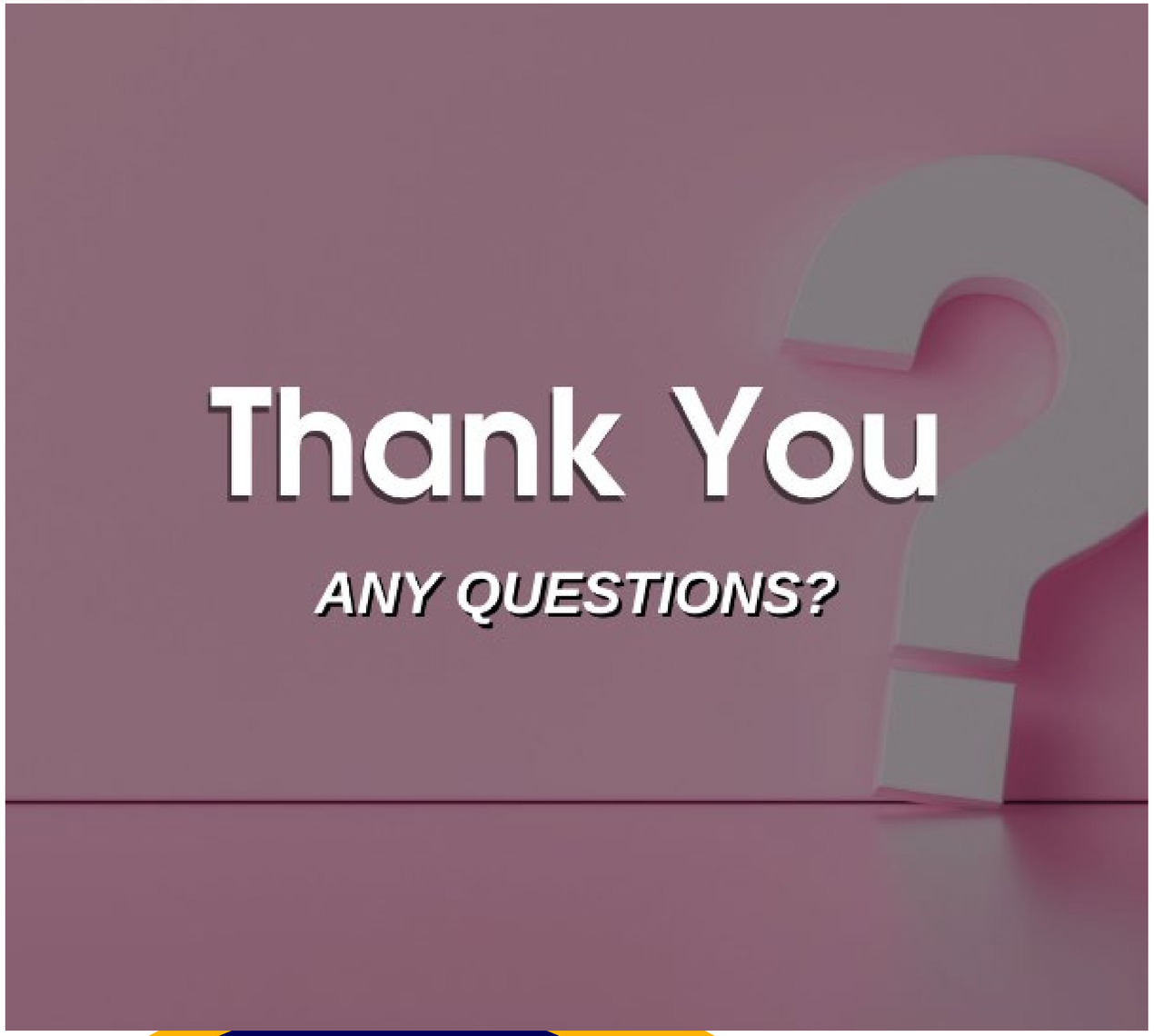
RTPO Dashboard – Well optimal point



Solution value to the Client

- Value recognized by operator from 12-month field test
  - **13% increase in condensate production**
  - ~50% reduction in gas lift gas used (~$3.9 M saving per year)
    - Operator bought most gas lift gas from 3rd party
  - Availability of an up-to-date model for immediate field re-optimization when upsets occur (e.g. compressor trip)
  - Better understanding of impact of planned changes

- What-if scenarios explored:
  - Gas/water/condensate constraints during maintenance
  - Opening/closing pipelines
  - New wells coming on-line
  - Shutting down wells
  - Lowering separator pressure
  - Changing pipeline velocity limits


Thank You
ANY QUESTIONS?