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R&D Council

Technical, Operational Challenges & Solutions-Innovations in Developing Unconventional Tight Oil High GOR Field, India

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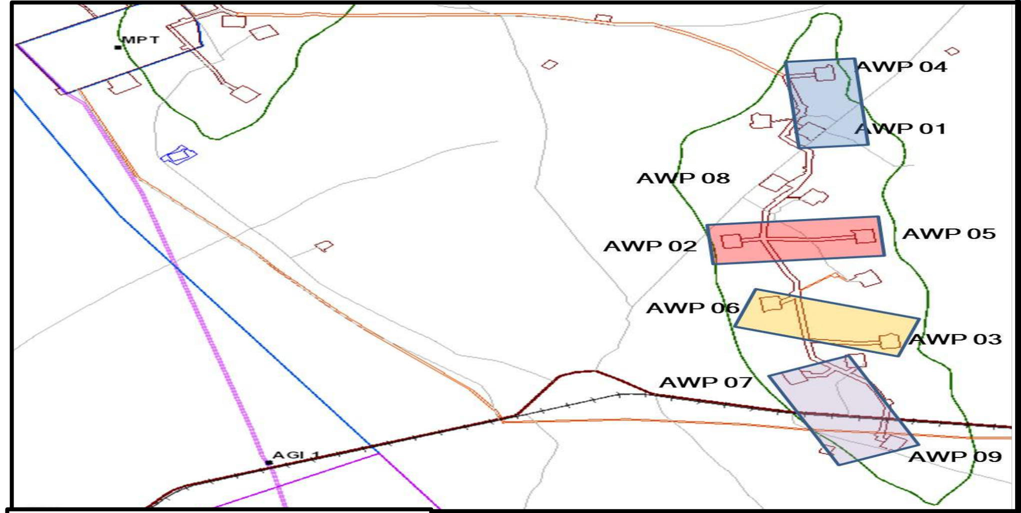
Field overview

- 55 Development wells (51 Horizontal & 4 Deviated Wells)
- HW ~2200 mMD (average lateral length ~1000 m)
- VW ~1300 mMD
- High CO_2 content (40% - 90%)
- Hydraulic Pumping Unit – 40-192 inches maximum stroke length.
- Lifting Capacity - 40,000 lb
- Max Stroke length- 0-192”
- Max speed- 3 – 4 SPM

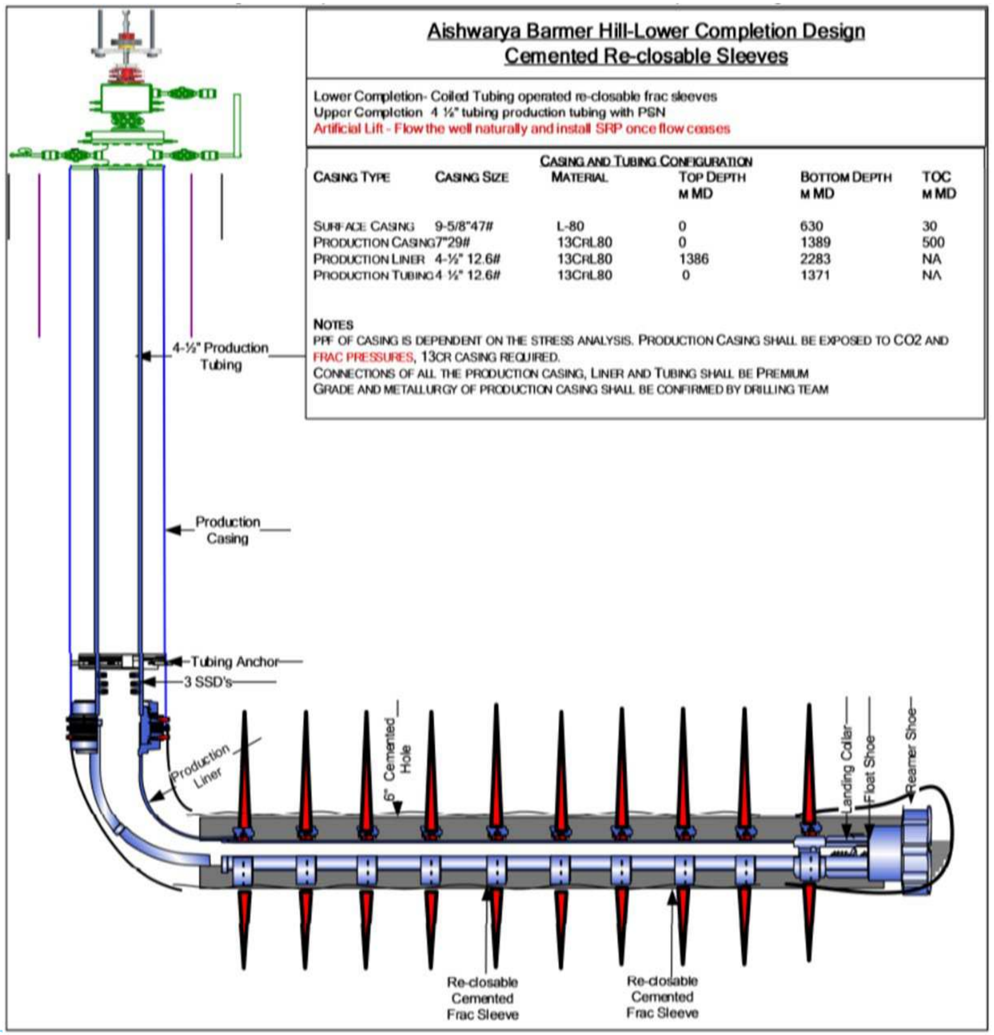


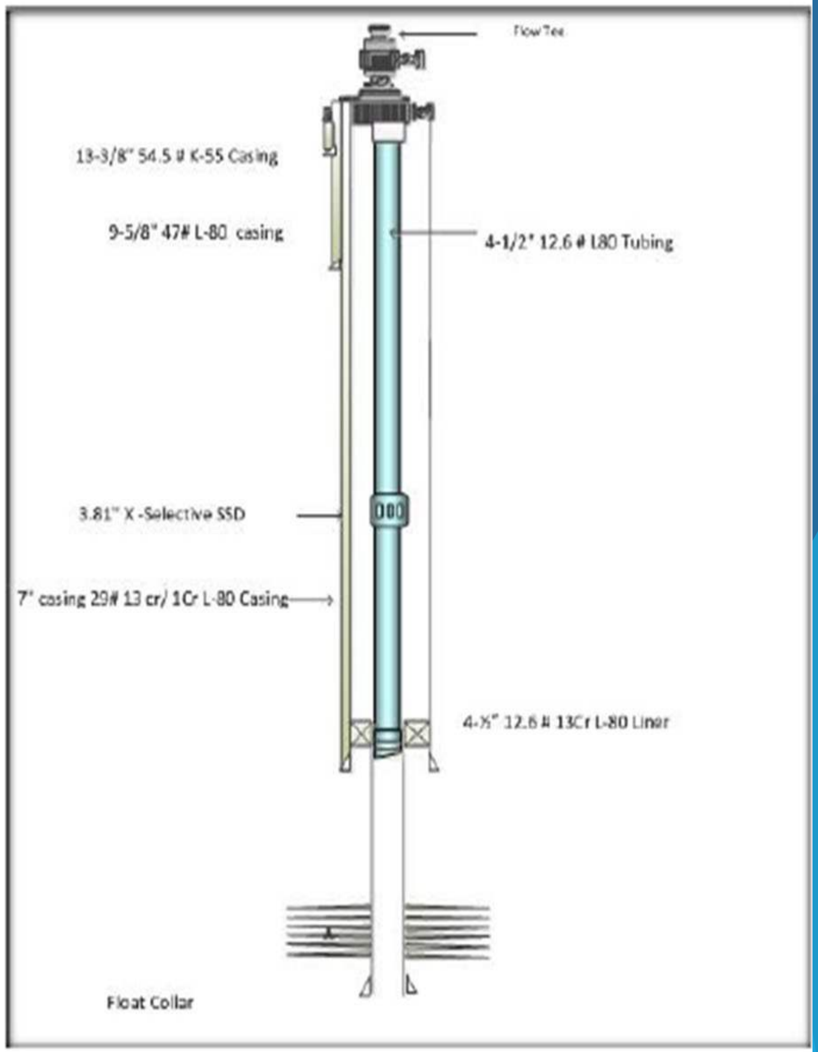
Reservoir Properties
- **Porosity:** ~24%
- **Perm:** ~1mD
- **Press:**~1510 psi
- **Temp:**~64 deg C

Fluid Properties
- **Oil Api:** ~30 Api
- **Viscosity:** ~3CP
- **Bubble Point:**~1450 Psi
- **WAT:** ~62.5 Deg C
- **Sol^n GOR:** ~100-3500 scf/bbl
-

Generic completion schematic

- Mostly horizontal wells
- All Packer less except one well.
- Long lateral length





Fracturing Strategy- Cased Hole-CT Operated Sl

Fracturing Strategy-Cased Hole-Plug and Perf

OPERATIONAL & TECHNICAL CHALLENGES AND RESPECTIVE SOLUTIONS & DIGITALIZATIONS

(1) LIFT & SRP SURFACE UNIT SELECTION

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OPERATIONAL & TECHNICAL CHALLENGES

- JET PUMP & SRPs were preferable
  - High drawdown requirement (~1000 psi)
  - Low PI (0.1-1.2 bpd/psi)
- JET PUMP was rejected, and SRP was selected because :-
  - High CAPEX & high OPEX cost
  - High pressure, HSE risks, fluid handling, etc
- Challenges with SRP:-
  - Large footprint
  - Difficult to install and remove

TECHNICAL, OPERATIONAL & DIGITAL SOLUTIONS IMPLEMENTED

- HRPs were selected
  - Less HSE risks, less footprint, easy to install/remove
  - More sophisticated
  - Long stroke length
  - Less CAPEX & OPEX

	Conventional Pumping Unit	Hydraulic Pumping Unit
Shipping	One unit in one to three trailer loads, depending on size	Up to four units on one trailer
Site preparation	Gravel, concrete slab, and piles	Mounts directly on the wellhead; skids are fully contained
Installation time	2–4 days	<6 hours
Footprint	10 ft × 10 ft or larger	Minimal, next to the well
Installation requirements	Specialized crew, cranes, and pickers	Turnkey equipment requires no site preparation or guide wires
Adjustments	Variable frequency drive required for production optimization	Operators can remotely control speed and stroke length†; independent up and down stroke speeds facilitate optimization
Maintenance	100% mechanical = frequent maintenance, high service costs, and increased downtime	Simplified maintenance requirements and intervals, reducing costs and downtime
Total cost of ownership	High capex due to cost of equipment; high opex due to maintenance and increased wear	Faster ROI due to lower capex and opex

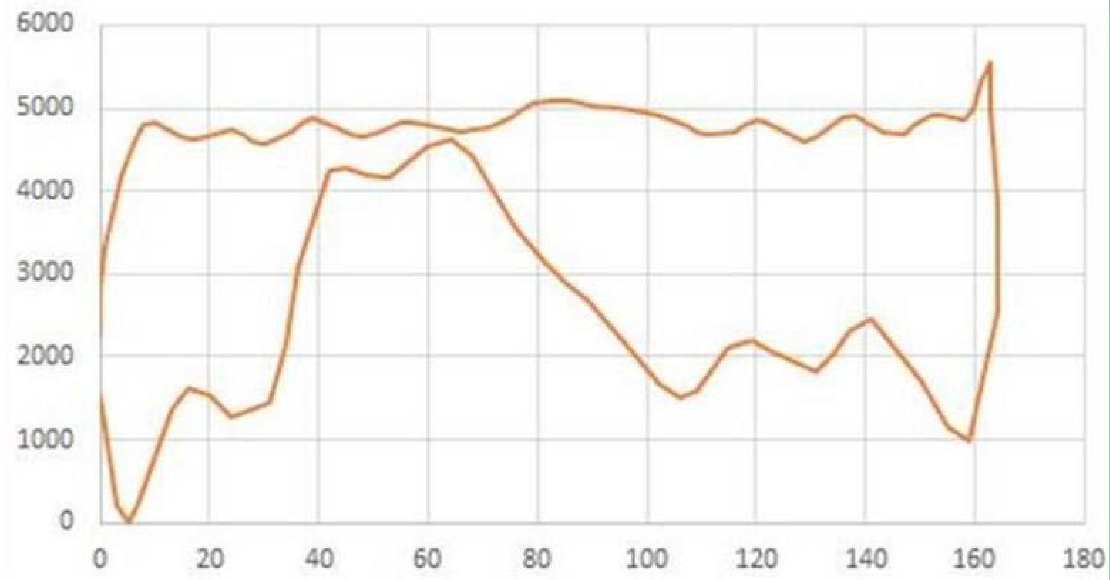
(2) SAND PRODUCTION

OPERATIONAL & TECHNICAL CHALLENGES

- SAND PRODUCTION – by reservoir pressure depletion
  - DOWNHOLE SUCKER ROD PUMP FAILURES:
  - WELL PI DECLINE: -

TECHNICAL, OPERATIONAL & DIGITAL SOLUTIONS IMPLEMENTED

- Sand screens (300 micron) installation –
  - 2-3/8” base pipe screen
  - 3.5” base pipe screen at tail pipe
  - Rig based WBCO to arrest this decline in productivity.



Sand, wax & scale layer on ball and seat of pump valve.

Well dyna-card due to sand influx in pump, pump failed in a few hours

(3) GAS INTERFERENCE & HIGH GOR ISSUES

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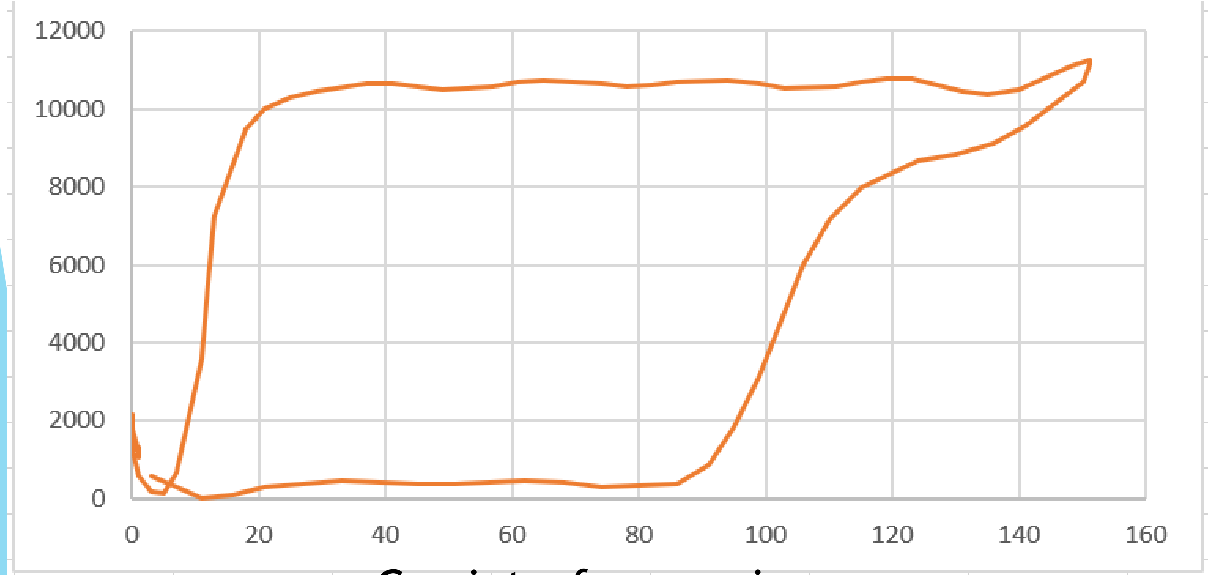
OPERATIONAL & TECHNICAL CHALLENGES

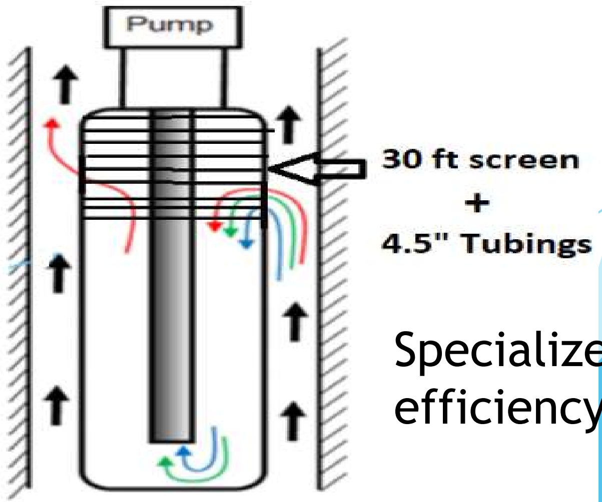
- 70% of the wells - high GOR (>500 scf/bbl)
- 40% wells - very high GOR (1000-4000 scf/bbl)
- Pump gas interference problems
- High slug flow tendency



Gas interference in

TECHNICAL, OPERATIONAL & DIGITAL SOLUTIONS IMPLEMENTED

- Downhole packer-based gas separator installation. But-
  - Additional 13 Cr packer cost,
  - Average efficiency of gas separation.
  - Difficulty in screen installation.
- Specialized gas separators were designed - Packer-less Poor boy type with longer dip tube length



Specialized high efficiency DHGS

(4) SURFACE CYLINDER TWISTING OF HRP UNIT

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OPERATIONAL & TECHNICAL CHALLENGES

- Surface cylinder installed over the well head twists (rotates) to & fro in the range of 20-120 degrees in some wells.
  - Risks of proximity rod break, possible damage to surface cylinder
  - High potential HSE incident.
- Immediate action to reduce the twisting
  - Ramp down the well which in turn reduces the rod string up & down movement time.
  - Oil loss from wells.

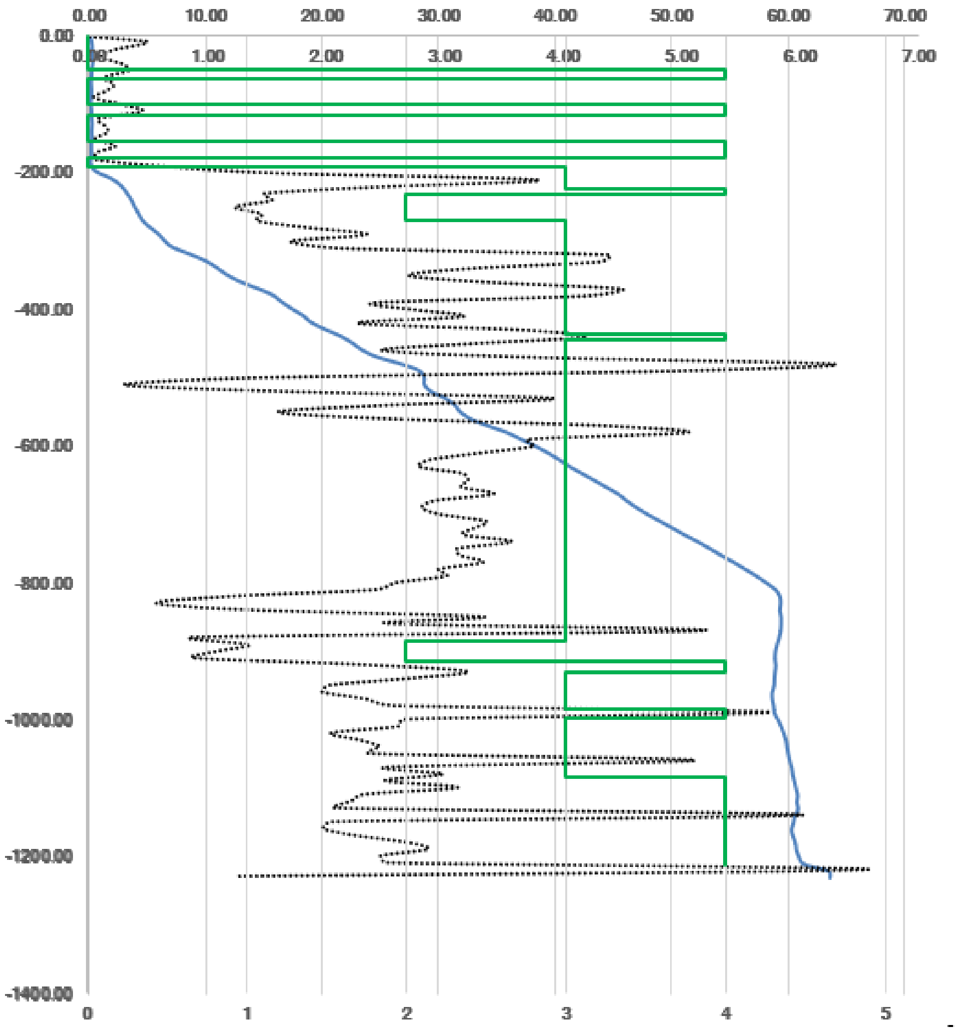
Surface Cylinder Twisting TO & FRO

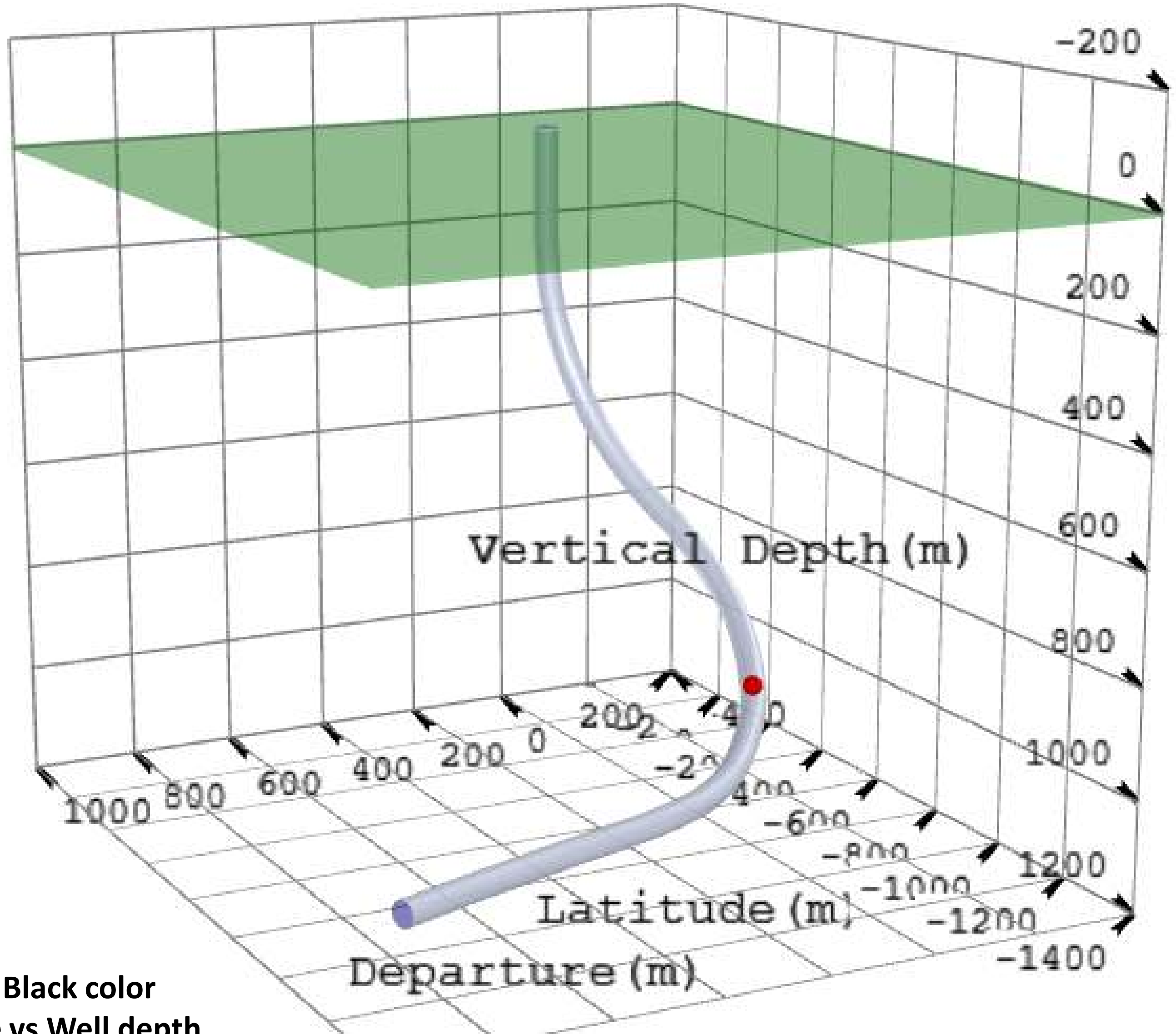
TECHNICAL, OPERATIONAL & DIGITAL SOLUTIONS IMPLEMENTED

- Reverse circulation with hot brine was done from annulus to tubing while running the sucker rod pump to clear any debris or scale leading to the rod string rotation.
- There was a possible theory of wax/sand bridge formation inside the tubing and along with high deviation of well in reciprocating motion, it can drive the guided rod string with the help of friction across contact area of rod guides.
  - Hot brine reverse circulation jobs reduced twisting but only sustain for 24-30 hours.
- Good short-term solution
  - Decrease in the surface stroke length by 10-12 inches.
  - Reduced the effectively displacement of rod string across the tubing wall
  - Resulted in ramping up of the well again and prevent oil loss upto 80%.
- Long term solution
  - Modified rod string design to lesser no. of guides.
  - Reduced surface cylinder Twisting from greater than 90 deg to 10 deg.
  - This novel design focuses on rod contact load with respect to complex well azimuth, high inclination, etc

ISOMETRIC VIEW of Well profile –COMPLEX AZUMITH & HIGH INCLINATION

Modified rod string design

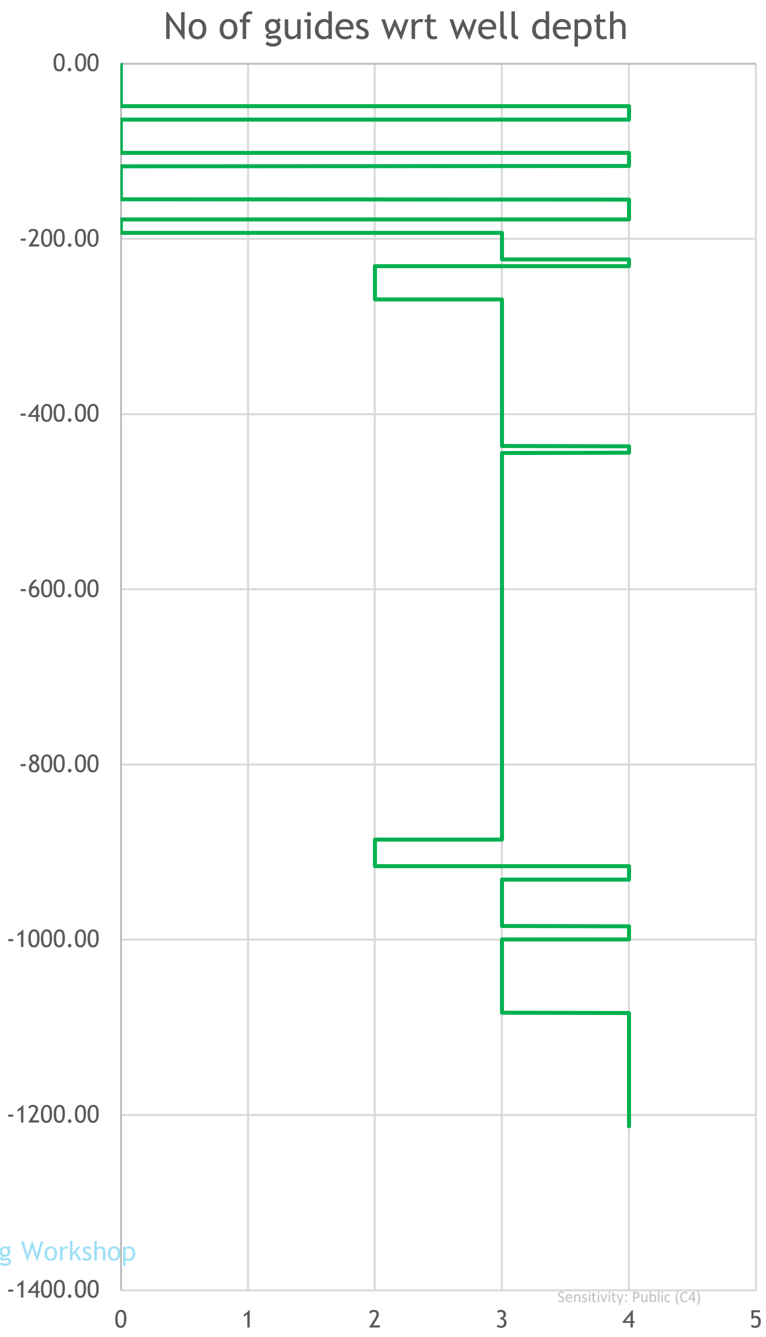


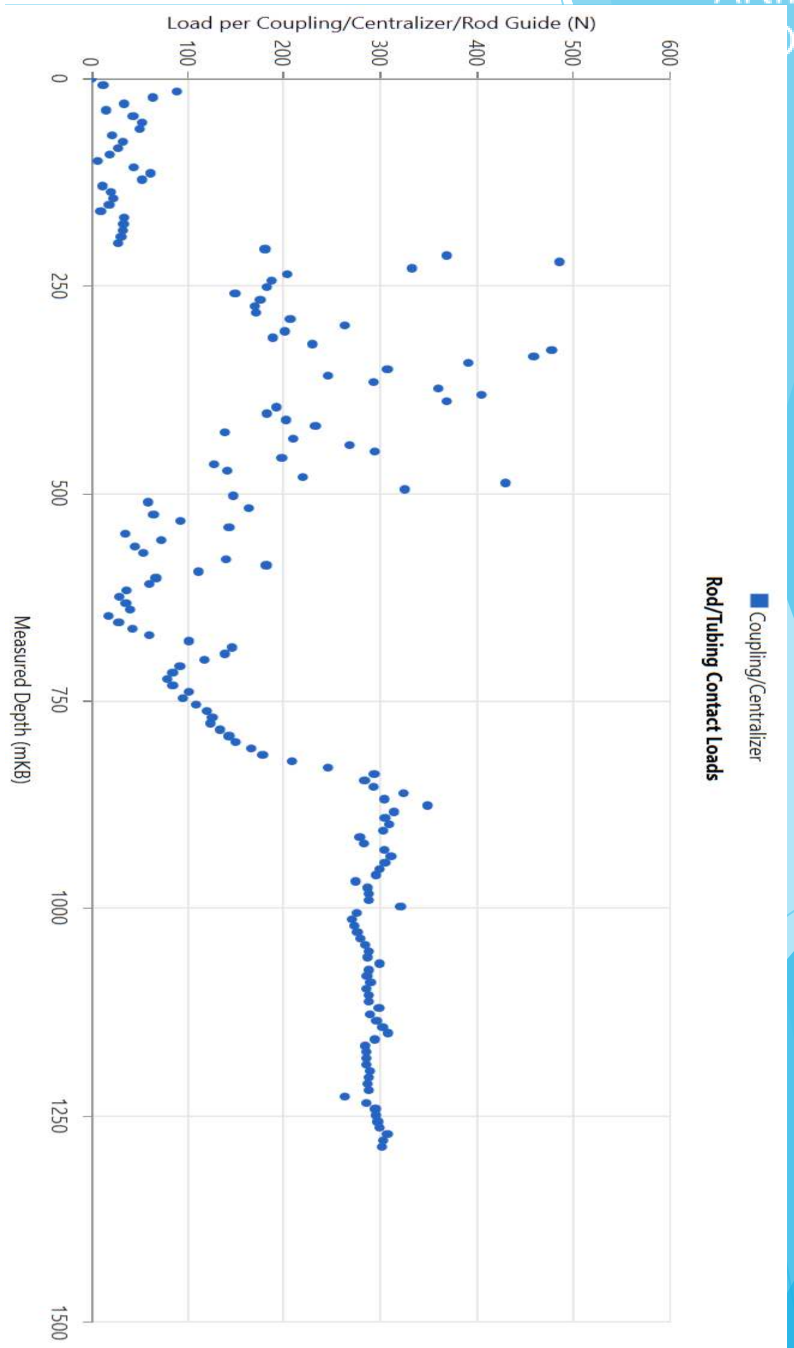


Green color is no. of guides (labeled at bottom of chart) vs Well depth, Black color trend is DLS vs Well depth and blue color trend is well inclination angle vs Well depth

Rod guides vs well depth and rod contact load vs well depth chart with well depth

New kind of rod-string design different from any conventional rod string design software for a sucker rod pumping well.



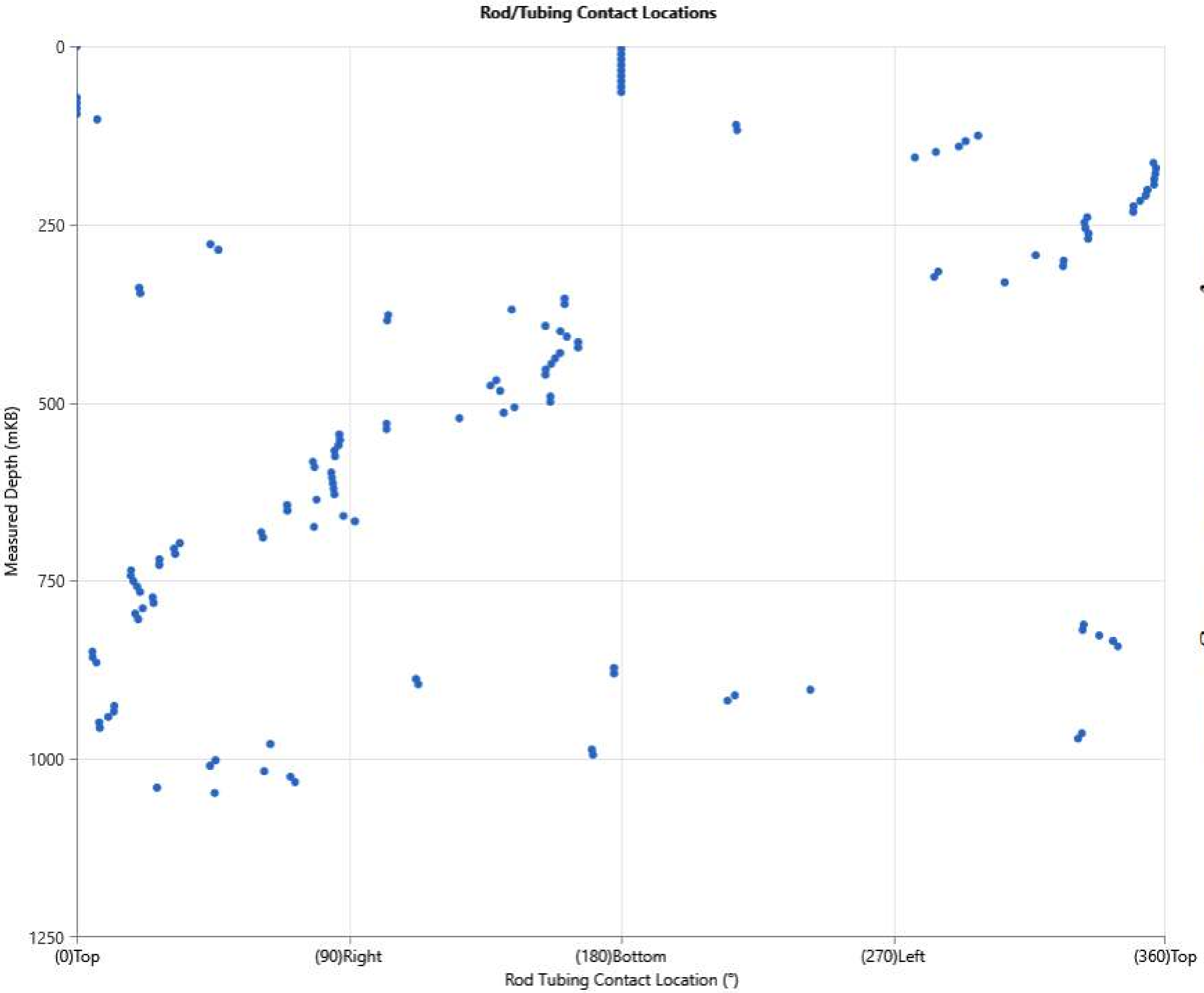


Analysis Results - Rod/Tubing Contact

Refer to the Rod & well’s contact load chart over 360 deg face of tubing inner wall

vs

Measured depth (m)



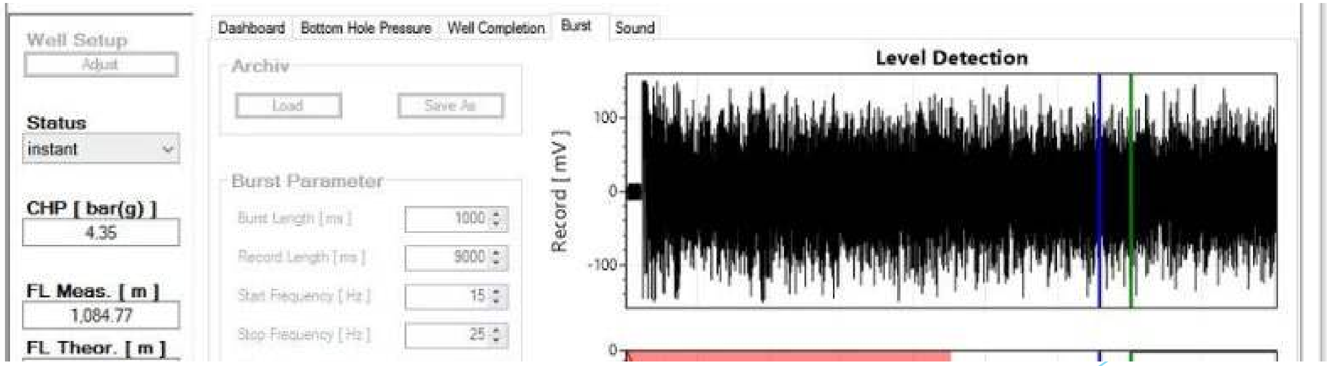
(5) ECHOSHOT DATA QUALITY

OPERATIONAL & TECHNICAL CHALLENGES

- The majority (~70%) of the wells in this field are having high solution GOR (>500 scf/bbl)
- 40% of the wells are having very high solution GOR (1000-4000 scf/bbl)
- Max. 40% of total gas flow comes via annulus, but in 40% of wells (~20 wells), DHGS is installed.
    - In DHGS wells, 90-100% gas produce via annulus
- The range of gas rate observed from annulus is in the range of 0.2-3 MMSCFD.
- These high gas rate creates noise signals in annulus which distorts the reflection peaks (1st, 2nd, and all the reflections)
- Sp.Gvty of annulus gas varies b/w 1.1-1.5, which changes sound vel.

TECHNICAL, OPERATIONAL & DIGITAL SOLUTIONS IMPLEMENTED

- One of the industry's patented technology was applied
    - It measure sound velocity using its calibration box on each well
    - Auto electronic sound wave generation – max. freq of 10 sec/data
    - Eliminated the requirement to install thick pup joints & collar count method to get fluid level.
    - It can listen to well noise freq and send freq range waves accordingly



High noise signal example from most of the wells

(6) WELLBORE CLEANOUT CHALLENGES IN HORIZONTAL WELL BORE

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OPERATIONAL & TECHNICAL CHALLENGES

- The ratio of vertical section to horizontal section in the range of 1 to 1.5 which is less.
- The lifting velocity required to lift sand in these wells is comparatively higher because of high deviation and lateral section.
- The ratio of lifting to settling velocity should be more than 5-6 times to properly lift the sand to surface.
- Formation sand and rock particles which are much bigger in diameter & size were also produced in addition to proppant sand while well bore clean out.
- The coil tubing unit and small rod running unit were unable to conduct wellbore cleanout operation because of inability to reach deeper in lateral section of horizontal wellbore due to high snubbing force requirement
- Due to depletion in reservoir pressure, which is the case in majority of wells, there have been severe fluid losses (more than 70%).
- The return rates in these wells are not enough to lift the sand till surface.

TECHNICAL, OPERATIONAL & DIGITAL SOLUTIONS IMPLEMENTED

- Modifications done in cleanout ways
  - Adopting reverse circulation - reduction in return flow area to get higher lifting velocity at same return rates.
  - Guar gum addition - water viscous in the range of 5-10 cP. To reduce settling velocity of particles by factor of 3-6 times.
  - To prevent formation damage surfactant addition was done.
  - These modifications improved return rate and sand lifting rate.

Size range of formation rocks & sand received at surface

(7) DYNA CARD, ALS PARAMETERS MONITORING & WELL OPTIMIZATION CHALLENGES

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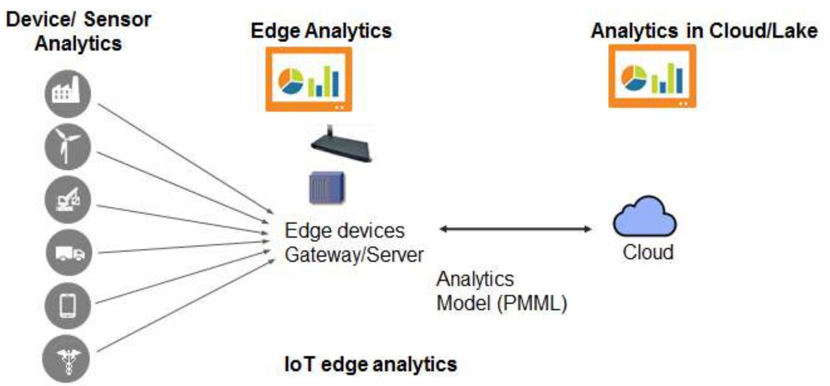
OPERATIONAL & TECHNICAL CHALLENGES

- Harvesting vast amounts of data has been identified as an enabler of operational performance improvement. The measurement of key performance indicators is a routine practice in well construction, but a systematic way of statistically analyzing well & lift performance against a large data bank of offset wells is not a common practice. The performance of statistical analysis in real time is even more rare.
- There were no arrangements of real time dyna card acquisition technology because of very high data frequency requirement that is 128 - 768 data points per minute.
- There were no platform for mapping both surface & downhole parameters at one place.
- All these complications impose challenges in optimizing the well & lift system performance.

TECHNICAL, OPERATIONAL & DIGITAL SOLUTIONS IMPLEMENTED

- There were 2 portals made to access digitalization platforms. First one on the basic powerBI application of microsoft and second portal was made with the application of edge devices.
- Power BI dashboard
  - A smart real time dashboard was built with historian data mapping.
  - It generates well trip alerts & alerts of well parameters threshold breach.
  - It also highlights issues in well performances in a lesser amount of time
  - Avoid/minimize well downtime in addition to remarkable data analysis & data visualization application of BI
- Edge AI devices and IOT solutions
  - This set up has the capability to control wells on real time majorly based on dyna cards behavior



MAJOR OBSERVATIONS & RESULTS

- Long horizontal lateral sections well bore cleanouts still poses serious challenges, especially in more depleted reservoir wells. It is observed more challenging in low GOR wells.
- It is detected that surface cylinder twisting is diminished by adoption of the modified unconventional design
- Conventional echo-shot gun generates fluid level peaks that are unreliable due to high gas noise in well annulus. So, accordingly different technology was adopted.
- It has been observed that due to high deviation, DLS (dog-leg severity) and vibration effects, thread from pump valve rod which inserts inside plunger and discharge sub unscrews in a few wells. Better thread connections or medium strength Loctite gel was observed to be suitable to prevent this problem
- For well modelling of these packer-less high GOR SRP wells, conventional steady state software are not effective.
- It was realized that the lower side of rod string guide were continuously in contact with tubing wall and because of continuous up & down reciprocation cycles, one side of rod guide was getting weared and others were not. This was resulting in decrease in rod run life. Refer to the figures beside. Gear based Rod rotator support was observed to be effective but with lever angle of ~60 deg

MAJOR OBSERVATIONS & RESULTS CONTD.

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- It has been observed that due to high deviation & high DLS of wells, the sucker rod pump valve rod gets damage/bend. Discharge sub guide of the pump is also observed to be damaged and broken due to valve rod movement. It has been observed in all the sucker rod pumps wells in this field. During pulled out pump refurbishment, same is changed every time
- Due to low productivity of well and less average liquid rate value (~270-300 bpd), the delta pressure (pressure drop) across the multi phase flow meter (MPFM) at well pad is generally very low. This DELTA-P value is required to measure the liquid rate by the MPFM. So, to measure well oil rates, hot water is required to be injected at surface to increase the total liquid rate to enter the MPFM. The water rate can be separately quantified in MPFM easily, since in most of the wells water cut is 0%.
- There was no equation/correlation available for actual production loss calculation in packer-less sucker rod pump well having very low productivity index. Wellbore storage effect in packer-less wells play important role in gradual production influx rate decrease. This case is applicable in constant rate producing sucker rod pumping well.
- There are a combination of exponential function which directly quantifies the production loss rate increase with time. As a result, whenever well is shut-in for short amount of time, the production loss number is comparatively less and unquantifiable.

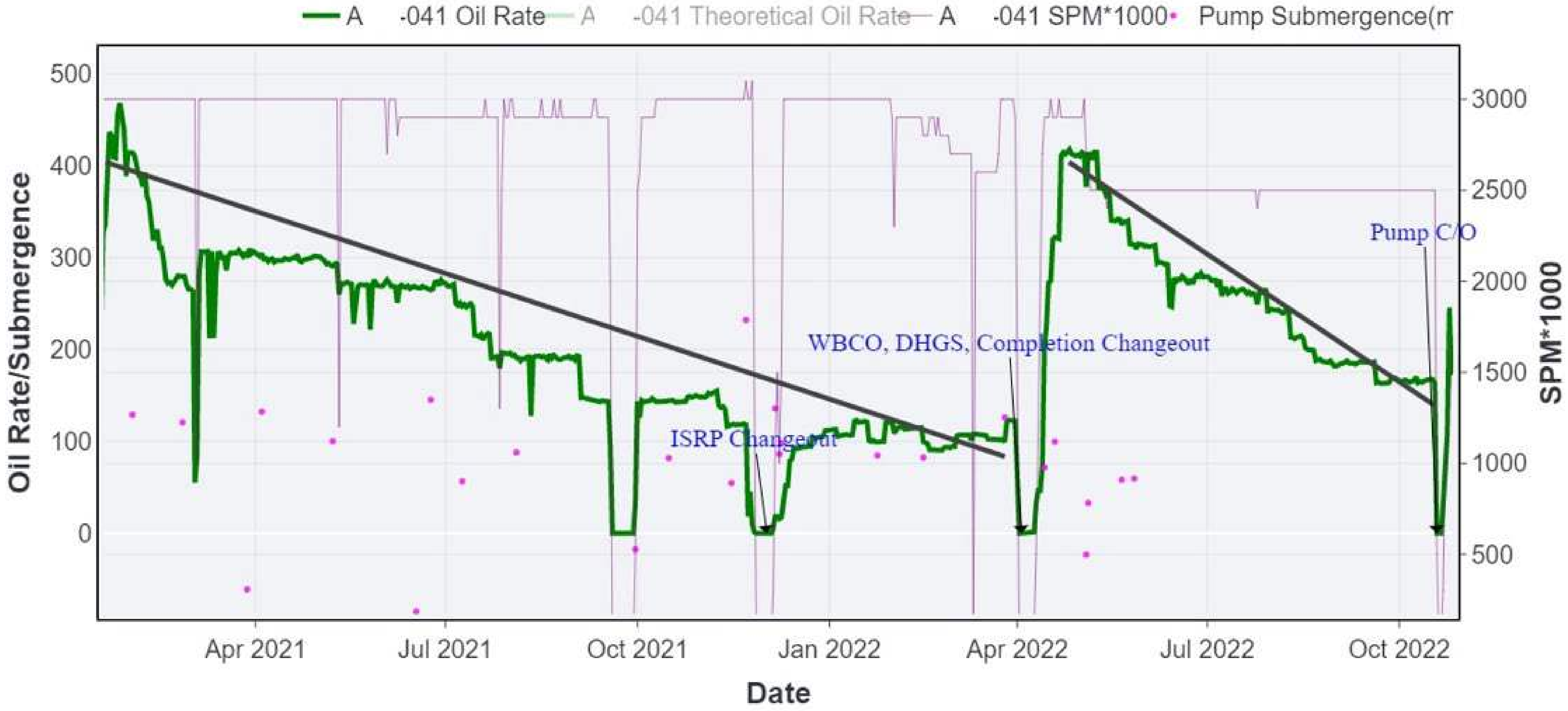
FIELD OBSERVATIONS: - ANALYSIS of Productivity index decline in screened-gas separator well

Using conventional tubing screen & downhole gas separation has major problem:-

- CATEGORY-1:- Well Productivity index and Production severe decline observed in wells where **no returns/sand lifting** was observed during wellbore cleanout by workover rigs and in wells where downhole gas separator is installed. It is observed that **SAND production increases due to increased pressure drawdown by gas separation resulting in well productivity index decline and pump failure in 30-60 days only**
- CATEGORY-2:- In wells where **good returns/sand lifting** was observed in WBCO+DHGS job, comparatively **Lesser productivity & oil rate decline is concluded**
- **REFER THE BELOW SLIDES FOR PROOF**

CATEGORY-1 WELLS

A-041: - It can be observed by the linear decreasing trend that of oil rate with production time. Frequent well productivity decrease due to sand production. Gas separator installed in April 2022, after which increase in sand production results in more steeper production decline linear trend



A-41:- Avg. Pump Intake Pressure 800 psi to 220 psi post separator installation

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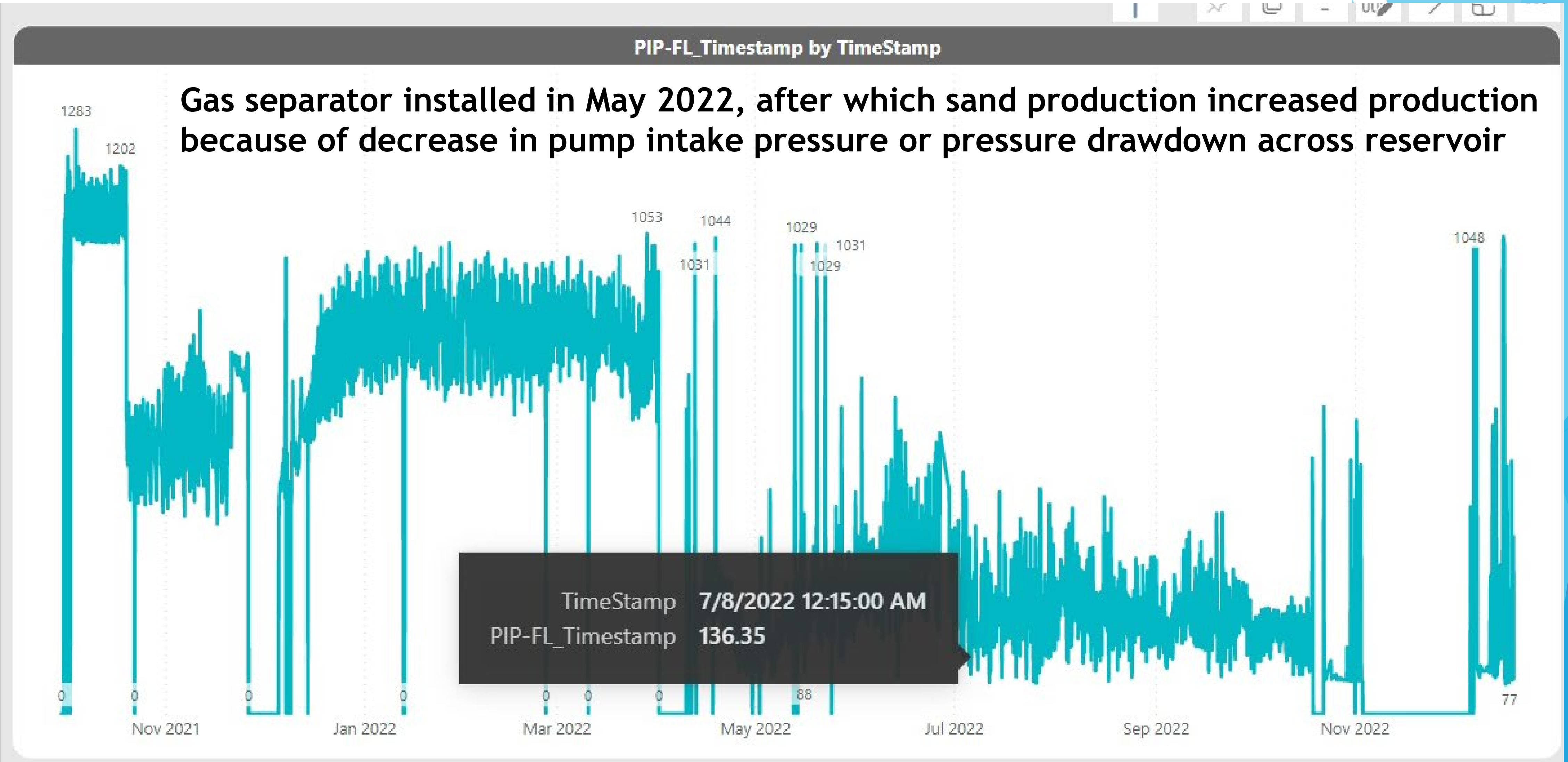
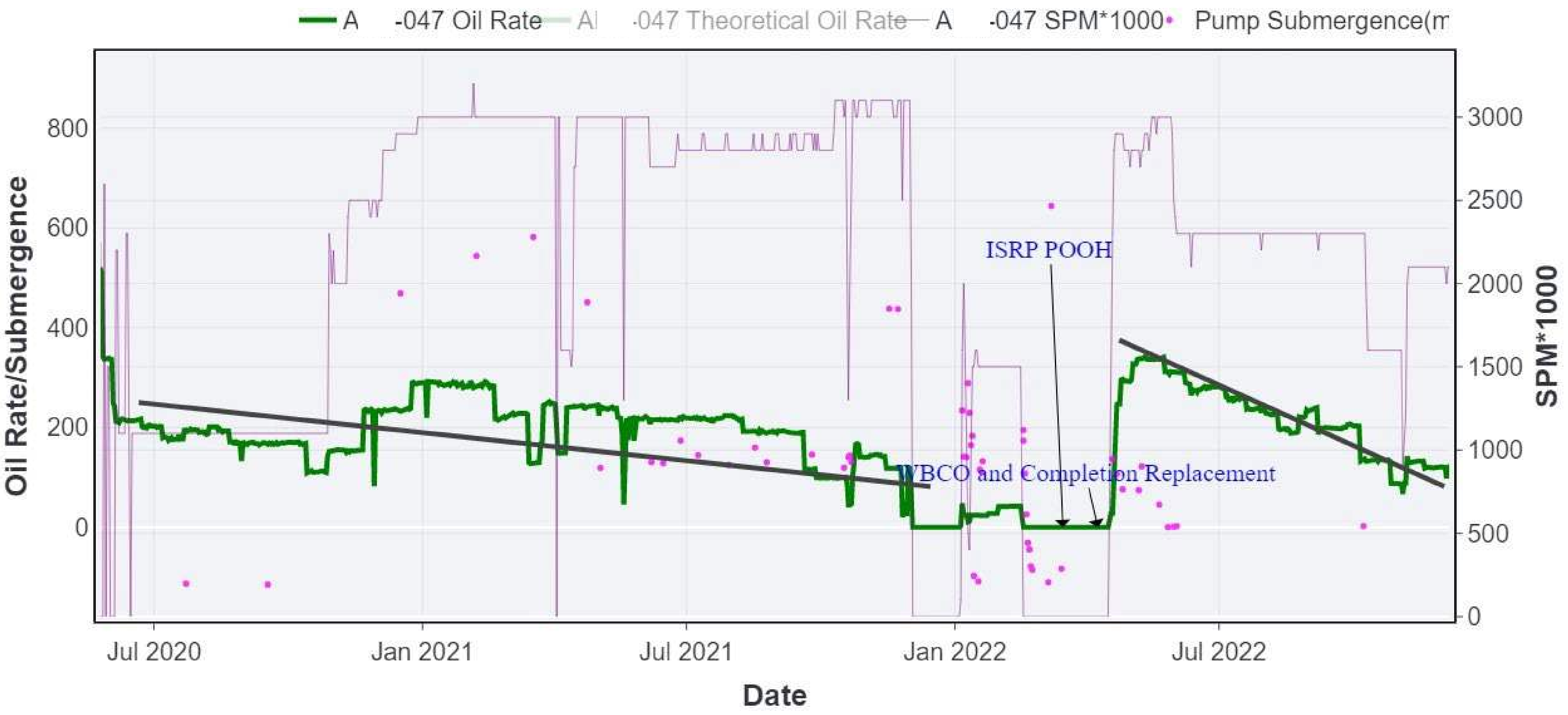


A-047: - It can be observed by the linear decreasing trend that of oil rate with production time. Frequent well productivity decrease due to sand production. Gas separator installed in May 2022, after which increase in sand production results in more steeper production decline linear trend



A-047:- Avg. PIP 780 psi to 250 psi post separator installation

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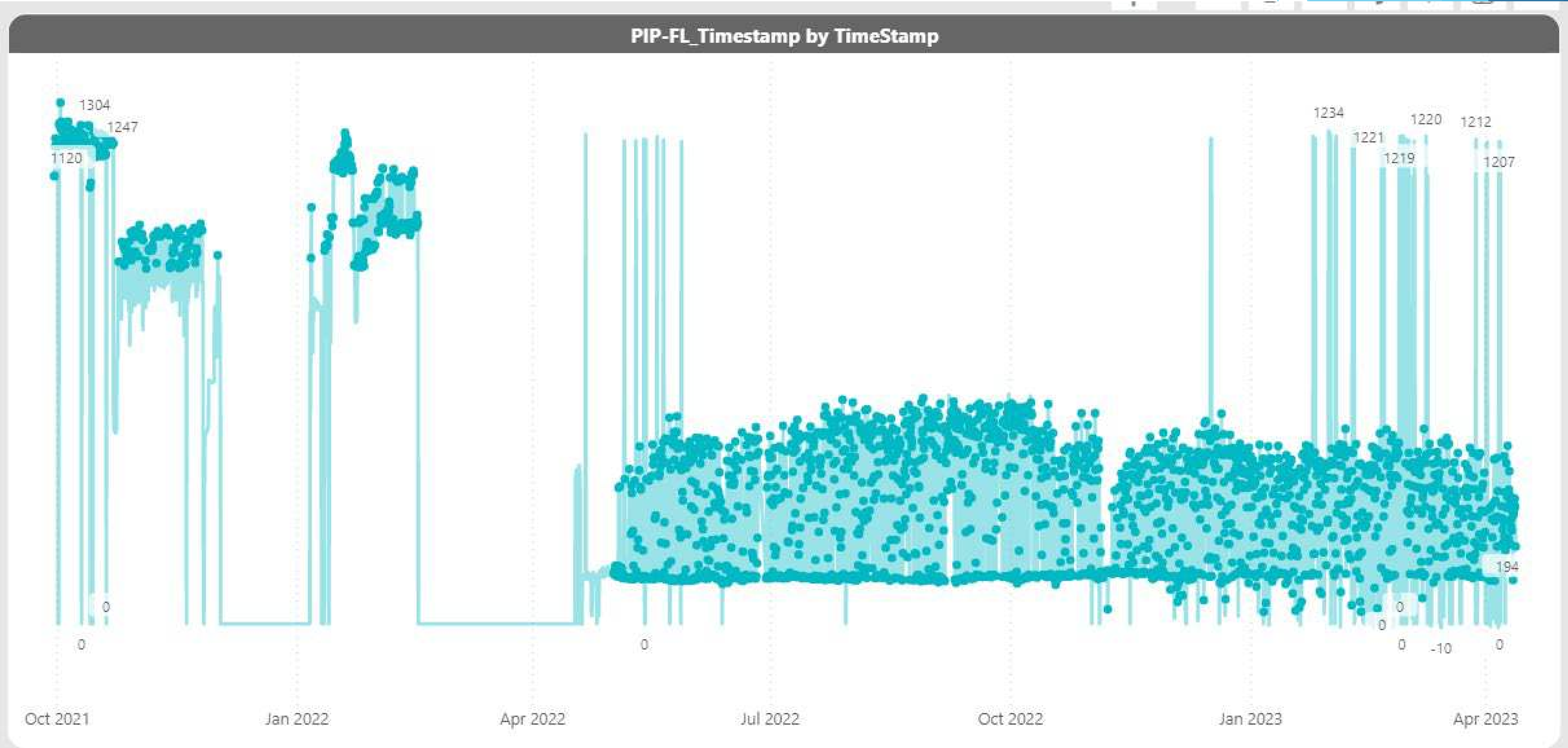
Gas separator installed in May 2022, after which sand production increased production because of decrease in pump intake pressure or pressure drawdown across reservoir



A-013: - Before downhole gas separator installation till Sept 2022, there was no production rate decline observed but after Gas separator installation, there was increase in sand production resulting in steep production decline linear trend

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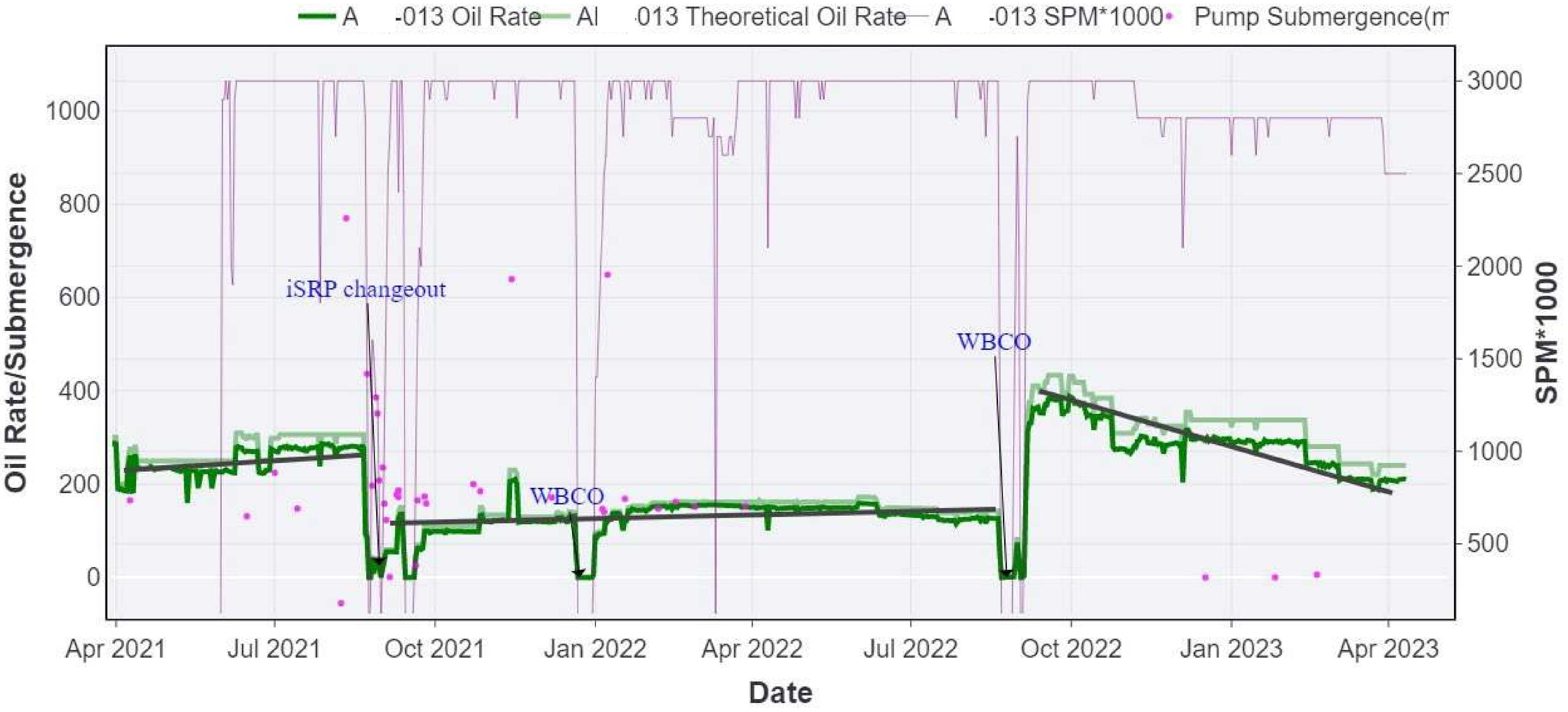
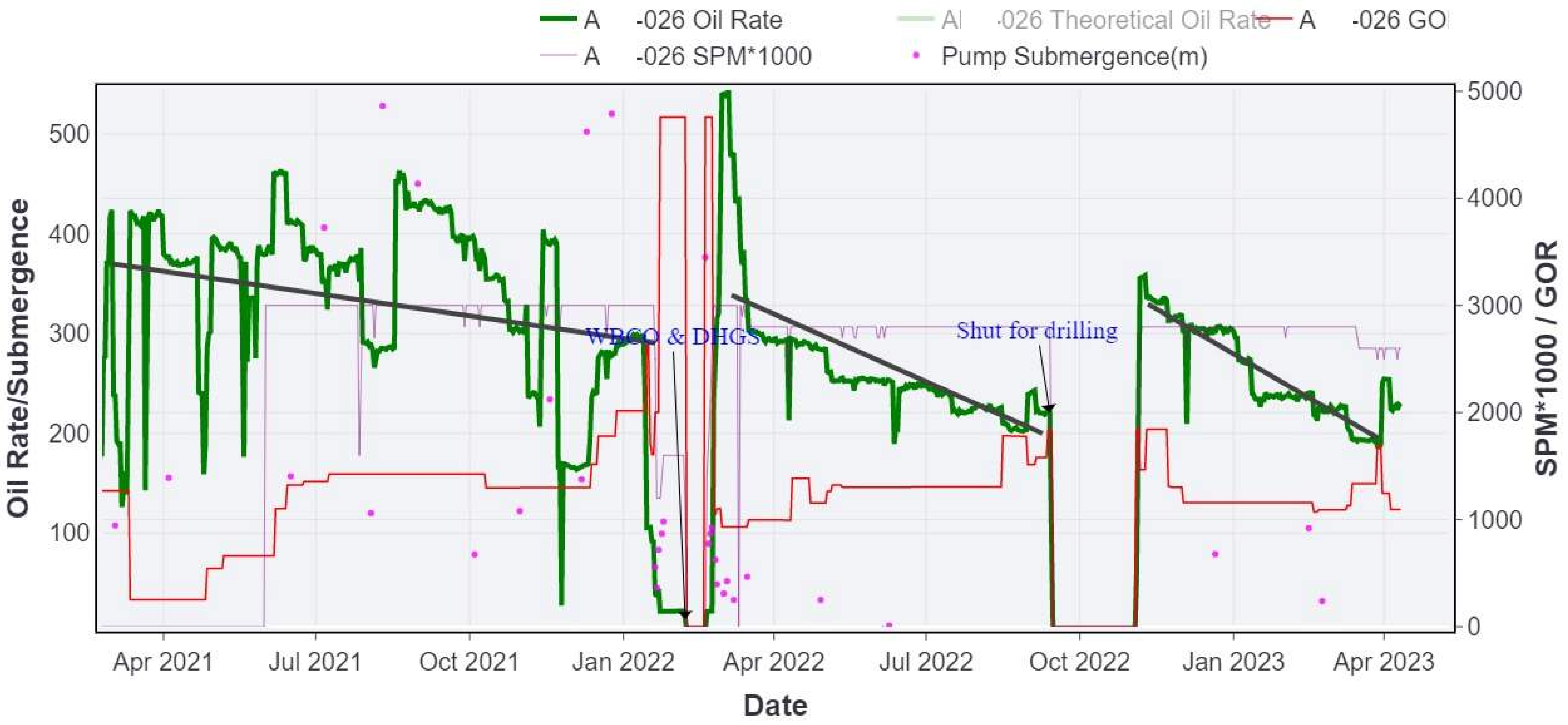


A-026: - Before downhole gas separator installation till April 2022, there was less production rate decline observed but after Gas separator installation, there was increase in sand production resulting in steep production decline linear trends



A-036: - Before downhole gas separator installation till Jan 2023, there was less production rate decline observed but after Gas separator installation, there was increase in sand production resulting in steep production decline linear trend

A-036 :- PIP comparison pre & post separator installation – 700 psi (prior) and ~70 psi (post)

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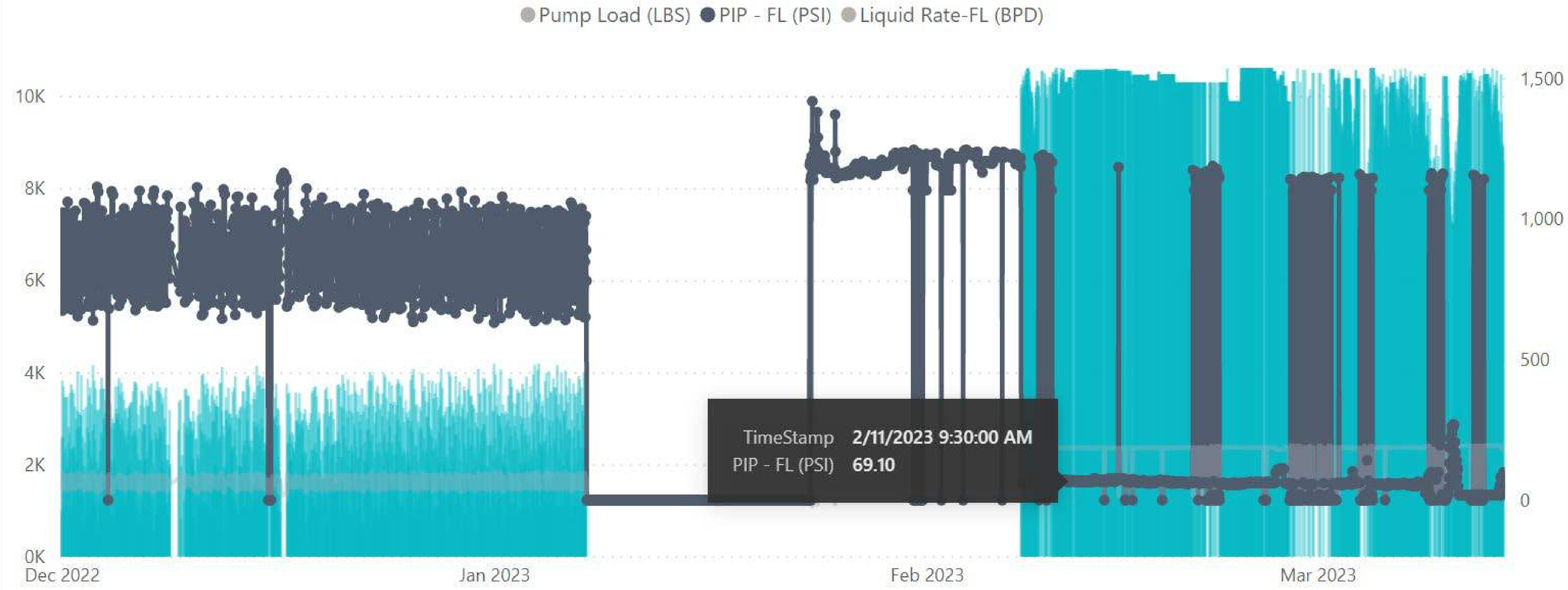
Gas separator installed in May 2022, after which sand production increased production because of decrease in pump intake pressure or pressure drawdown across reservoir



ANALYZATION OF THE ABOVE-MENTIONED PROBLEMS OF PRODUCTION DECLINE, ASSOCIATED POSSIBLE SOLUTIONS & RESULTS

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- In fields where sand production occurs along with oil and gas production, there are frequent down-hole sucker rod pump failures. If sand production is prevented by installation of sand screens at pay-zone section across the casing or liner sections, then the well productivity is affected due to choking of these screens and inaccessibility of retrieving these permanently installed screens. If tubing tail pipe screens are used, then sand is filtered at screen and settled in wellbore. The continuous sand settling in wellbore preferably at high dog leg severity sections results in well productivity decrease. The well productivity is also hampered when the tubing screens are choked by sand creating extra pressure loss and oil rate loss.
- In many wells where high gas rate is an issue, well cannot produce effectively without use of downhole gas separator. If gas separators are installed along with tubing-based sand screens, then again similar problems are faced related to well productivity decrease because of either sand choking the screens or sand settling in wellbore sections gradually creating sand bridges.
- Below are the advantages of this new design invention -
  a. Efficient and enhanced well production life
  b. Prevent oil rate gradual loss with time due to well productivity decrease by sand accumulation in well - This saves many hundred thousand barrels of oil which cost millions of dollars
  c. Prevent requirement of well bore cleanout by workover rigs or coil tubing units which takes many days – These saves millions of dollars by saving expensive day rate cost of rigs, coil tubing units, brine, and other chemicals
  d. Save well downtime due to no requirement to shut oil well for wellbore cleanout – It saves 1 week to 3 weeks of well production loss (well downtime), saving thousands of barrels of oil loss & associated revenue.
  e. Save expensive downhole sucker rod life pumps, and other accessories: - Frequent failures of downhole pumps and other accessories result in continuous change out of downhole pumps. This saves many hundred thousand dollars per year.
  f. Save well downtime by avoiding well shut due to downhole pump changeout by small workover rod running rigs: – It saves Minimum 2-3 days of well production loss (downtime), saving hundreds of barrels of oil & associated revenue.
  g. Uninterrupted long gas separation supported high production rate access from oil wells
  h. Very high gas separation efficiency (>700 barrels per day at 100% gas separation efficiency)

- It is a completely field-tested design resulting in oil production saving and enhancement.

WHY in-house innovation design– “ADVANCED DOWNHOLE GAS AND SAND SEPARATOR SAFEGUARDING WELL PRODUCTIVITY DECLINE BY SAND” better & suitable?

a. It targets both sand and gas filtering with no side effects related to well productivity decline.
b. Efficient and enhanced well production life
c. Prevent oil rate gradual loss with time due to well productivity decrease by sand accumulation in well - This saves many hundred thousand barrels of oil which cost millions of dollars
d. Prevent requirement of well bore cleanout by workover rigs or coil tubing units which takes many days – These saves millions of dollars by saving expensive day rate cost of rigs, coil tubing units, brine, and other chemicals
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h. Uninterrupted long gas separation supported high production rate access from oil wells
i. Very high gas separation efficiency (>700 barrels per day at 100% gas separation efficiency)

- It is a completely field-tested design resulting in oil production saving and enhancement

OBSERVATION related to tight oil field challenges of estimation of reservoir pressure depletion, productivity index, fluid level estimation, actual production loss number post well shut-in

Oil wells reservoir pressure and productivity index keeps on changing during the life of an oil well (5 - 25 years). The production rate numbers are very critical which can only be calculated if reservoir pressure and productivity index of the well at certain point of time is known. Without production rate number oil and gas companies cannot monitor and keep track of their production outputs and thus their revenue.

In cases of decreasing oil production from wells, it is very critical for the oil and gas companies to restore or even increase the production from their oil wells. Oil loss is the key information to allocate & report post OIL well shut in. It was important to calculate the actual oil production loss numbers when a packer-less well is shut-in. High permeable formation takes less time for equilibrium establishment whereas low permeable reservoir takes much more time for the same. The actual oil loss from a packer-less well in tight oil reservoir is not direct, that is oil rate multiplied by shut-in time. When a packer-less well in a tight oil formation (running on sucker rod based downhole pump) is shut-in for a few hours then the actual oil loss is comparatively less. Oil loss rate increase gradually with time at exponential rate.

This derived equation/algorithm is a function of exponential-based functions of the liquid column rise or bottom hole pressure rise with time in well, oil influx rate decrease trend with time during transition phase of well shut-in along with estimation of various important parameters which are very valuable to any oil and gas company.

Below is the list of these parameters which are result of this work:-

a. Estimate actual reservoir pressure or reservoir pressure depletion (which is difficult in low Productivity index tight oil field wells)
b. Estimate oil well productivity index
c. Estimate actual production loss in packer-less oil wells (considering wellbore storage behavior) at any point of shut-in time
d. Estimate oil rate influx trend (decreasing trend) at any point of shut-in time
e. Estimate downhole pump submergence trend in case of packer-less oil wells at any point of shut-in time
f. Estimate oil well production rate prior to oil well was shut-in
g. Estimate oil well fluid actual density or water-cut in well fluid

Equation observation & results

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There are 4-4 equations derived with the help of Modified Vogel work & inflow performance relationship

The equation are derived as main function of shut-in time-

1) Column rise trend (time)
2) Pump intake Pressure rise trend (time)
3) Liquid rate decrease trend (time)
4) Actual oil loss trend in barrels (time)

1) The equations are function of Casing head pressure, , gas column hydrostatic pressure, productivity index, initial pump submergence, well fluid density, well capacity per feet, reservoir pressure.
2) RESULTS OF BOUNDARY CONDITION – VERIFIES THE END RESULT

- At t = 0,
  - H[t=0] (Pump submergence at shut-in time “t”) = H_initial (Pump submergence at shut-in time zero)
  - Q-liq rate[t=0] (Liquid rate at shut-in time t=0) = J (Pr-Pwf) , where J = Productivity index, Pr = Reservoir Pressure, Pwf = flowing bottom hole pressure
- At t = infinity
  - H[t] (Pump submergence at shut-in time “t”) = (Pr at pump depth – CHP – Gas column hydrostatic pressure)/Fluid density
  - Q-liq rate [t] = 0

WHY THE DERIVED CORRELATION/EQUATION IS BETTER & SUITABLE?

1) It takes weeks a few hours of bottom hole shut-in pressure data even in case of low productivity index wells, which is highly economical as it results in millions of dollars of revenue loss saving
2) It does not consider the reservoir properties and fluid properties except the fluid density which can be measured on surface very easily. This fluid gradient can also be predicted as output of the method
3) It has no dependence on well life
4) It does not require support of expensive surface well testing unit, instead a few echo-shot points from well annulus in case of packer-less wells or downhole pump intake pressure data in case of packer wells
5) It does not require surface production rate measurement which is a big challenge in low productivity wells and where resources are not available to measure
6) The productivity index of these wells is also estimated using the reservoir pressure data with very short amount of well shut-in time
7) This solution estimates the actual production loss (barrels of oil) due to wellbore storage effect after low productivity well (in which partial pump fill-age occurs) is shut-in
8) In various cases where oil wells production rate is not known because of multiphase flow meter (MPFM) problem, unavailability of multiphase flowmeter (MPFM) or very low-production rate numbers which cannot be measured by flowmeters, this method can be easily applied to estimate well production rate
9) In cases of SUCKER ROD PUMP SUPPORTED WELLS in which dyna-card data is erroneous due to gas influx in downhole pump, it determines fairly accurate well production rate
10) This correlation Invention determines the downhole pump submergence numbers without usage of echo-shot gun, thus saving cost of echo-shot survey cost. This is possible if the available data for reservoir pressure and productivity index of well are reliable

DERIVED EQUATIONS FIELD VERIFICATION

Artificial Lift R&D Council

A tight oil well shut-in build up column rise data (comparison of curve equations with actual downhole data taken by automatic fluid level echo-shot device)

After long shut-in -

Pump submergence stabilized at – 243 mTVD

Pr_at pump depth calculated at CHP of 4.26 bar = 362 psi

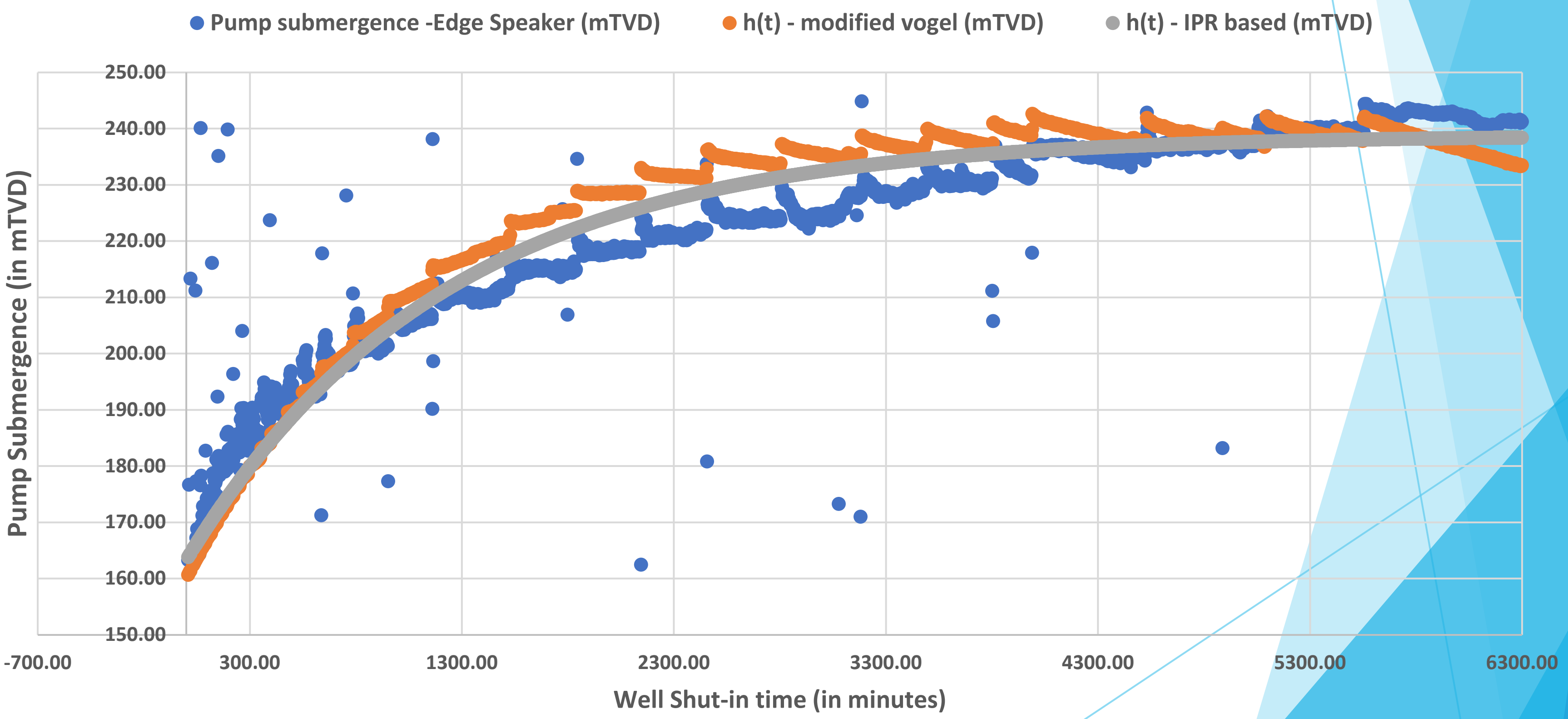
Observations by curve matching :-

Pr ~ 490 psi (~360 psi at pump depth), whereas expected was >950 psi

PI matched ~0.1 bpd/psi

Where, Pr = Reservoir pressure, CHP – Casing head pressure

Column-rise Equation verification by build up data of by automatic fluid level echo-shot device



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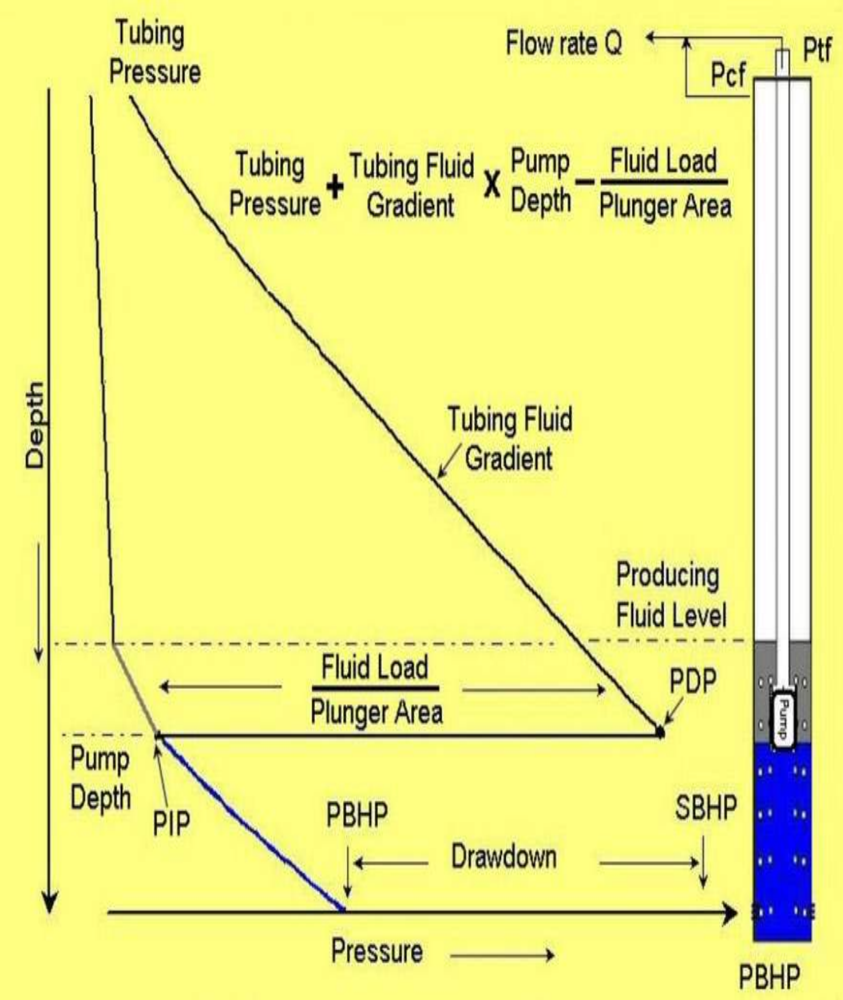
CONCLUSIONS

- Sand production from wells is necessary especially when wellbore cleanout is difficult, efficiency of the same is not good and cleanout sustenance is also a challenge.
- So, an in-house innovation design– “ADVANCED DOWNHOLE GAS AND SAND SEPARATOR SAFEGUARDING WELL PRODUCTIVITY DECLINE BY SAND” which prevented sand production, prevent sand to lay in the well-bore section and provide efficient gas separation was made, implemented & patented
- It is necessary to deploy real time data monitoring tools to monitor high number of wells effectively.
- IOT devices are great medium to provide real time dyna-cards, they provide pump control function, data analysis & other functions which are essential to run SRP well to achieve maximum pump & rod run life
- A good technology echo-shot device is necessary for fluid level detection, especially in cases of diversified annulus gas specific gravity or high solution GOR. The sound velocity in annulus is highly dependent on specific gravity under pressure value of 600-700 psi. The same was adopted in this field which could easily differentiate the actual fluid level signal by transmitting and receiving frequency range waves other than the gas noise frequency range observed from well in listening mode.
- Jet pump-based lift and cleanout ways can be very effective in frequent sand production to prevent well productivity drop. Similar technologies are sought in market, and this can be very effective in conducting balanced (underbalance) pressure condition cleanout operations. A pilot of the same is planned in future



CONCLUSIONS CONTD.

- Medium strength Loctite solutions can easily arrest the vibration-based unscrewing of thread from plunger with 100% efficiency.
- For well modelling of packer-less SRP wells, dynamic multiphase software are very effective.
- To prevent premature rod guide wear and rod failure, rod rotators were very effective. They rotate the rod string 360-degrees in 24 hours. This reduced the rod guide wear from one side and increased rod guide and rod body run life.
- Dyna card fluid load parameters were found to very effective in pump intake pressure calculation. It was found to be reliable (in the range of 10-20 % when compared to echo-shot based pump intake pressure calculation).
- Actual production loss equation with respect to time of shut-in was derived and verified with the column rise rate trend (detected with echo-shot fluid level).
- THE DERIVED CORRELATION/EQUATION IS BETTER & SUITABLE to estimate well reservoir, production and surveillance parameters very effectively

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