Improvements in ESP Designs in Non-consolidated Sandstone Reservoir and Mature Field, Marine Region, Mexico*

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Abstract

This presentation documents field experiences and integral solutions implemented in wells through technical analysis between Baker Hughes, a GE Company, through multidisciplinary work with our main client in Mexico.

The integral solutions evaluated include:

- Productivity evaluation and definition of critical pressure drop per well through nodal analysis
- Evaluation of reservoir characteristics and optimal production rates and fluids properties
- Drainage area analysis between nearby producing wells
- Analysis of existing well completion and sand control techniques
- Implementation of corrective cleaning in producing wells through ESP (Electrical Submersible Pump) systems
- Improvements in ESP designs, like special configuration, such as stabilized pumps, mixed flow stages, abrasion resistant materials, and others. As well techniques of surveillance, monitoring and diagnosis of wells
- Improvement of ESP completion through implementation of downhole tools to separate solids that extend the ESP run life

The success of this evaluation has several key factors based on the goals set by the operator and the ESP supplier. This common goal is maximizing ESP run life and well performance without adding to well downtime. This presentation describes several benefits achieved through interdisciplinary work, including expanded reservoir evaluation, lower completion analysis enhanced and well productivity.

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Improvements in ESP designs in Non-consolidated sandstone reservoir and mature field Marine Region – Mexico

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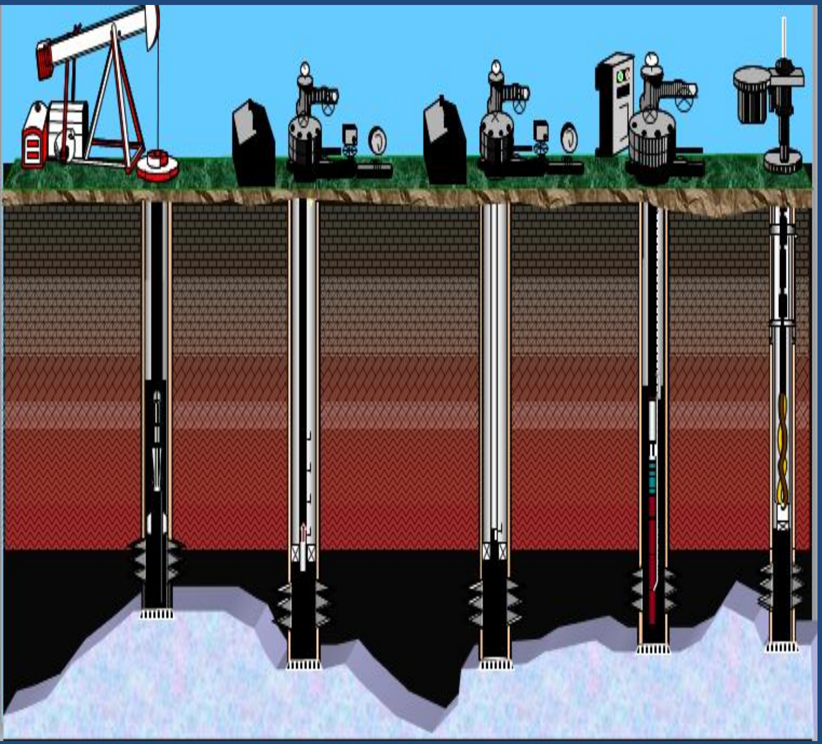
Today's agenda

- Introduction.
- Workflow : Productivity and Reservoir evaluation.
- Description & Considerations for improvements in ESP designs.
- Reservoir characteristics.
- Productivity analysis & Improvements in ESP designs.
- Implementation of downhole tools to separate solids that extend the ESP run life.
- Conclusions.

Introduction

Once natural lift becomes insufficient, artificial lift methods are employed to lift the fluid, allowing additional flow.

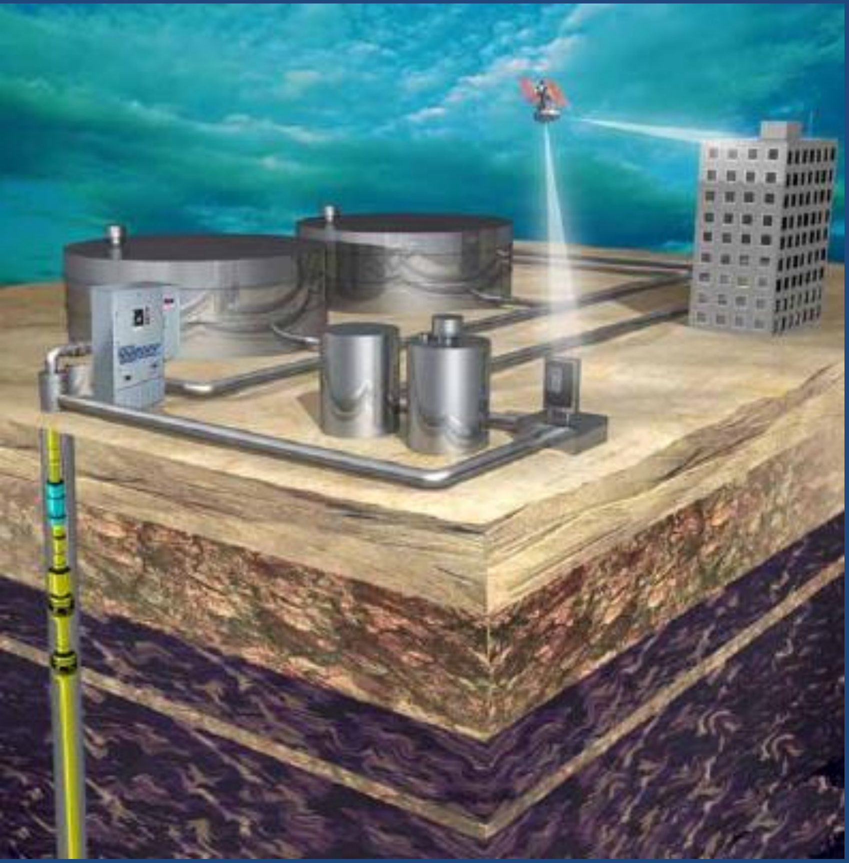


The electrical submersible pump systems deliver an effective and economical way of lifting large volumes of fluids from great depths under a variety of well conditions.

The ESP is a very versatile artificial lift method that can be operated in different and harsh environments all over the world.

<u>In most fields in the marine Region of Mexico, the ESP is the most adequate system due to the reservoir and well conditions.</u>

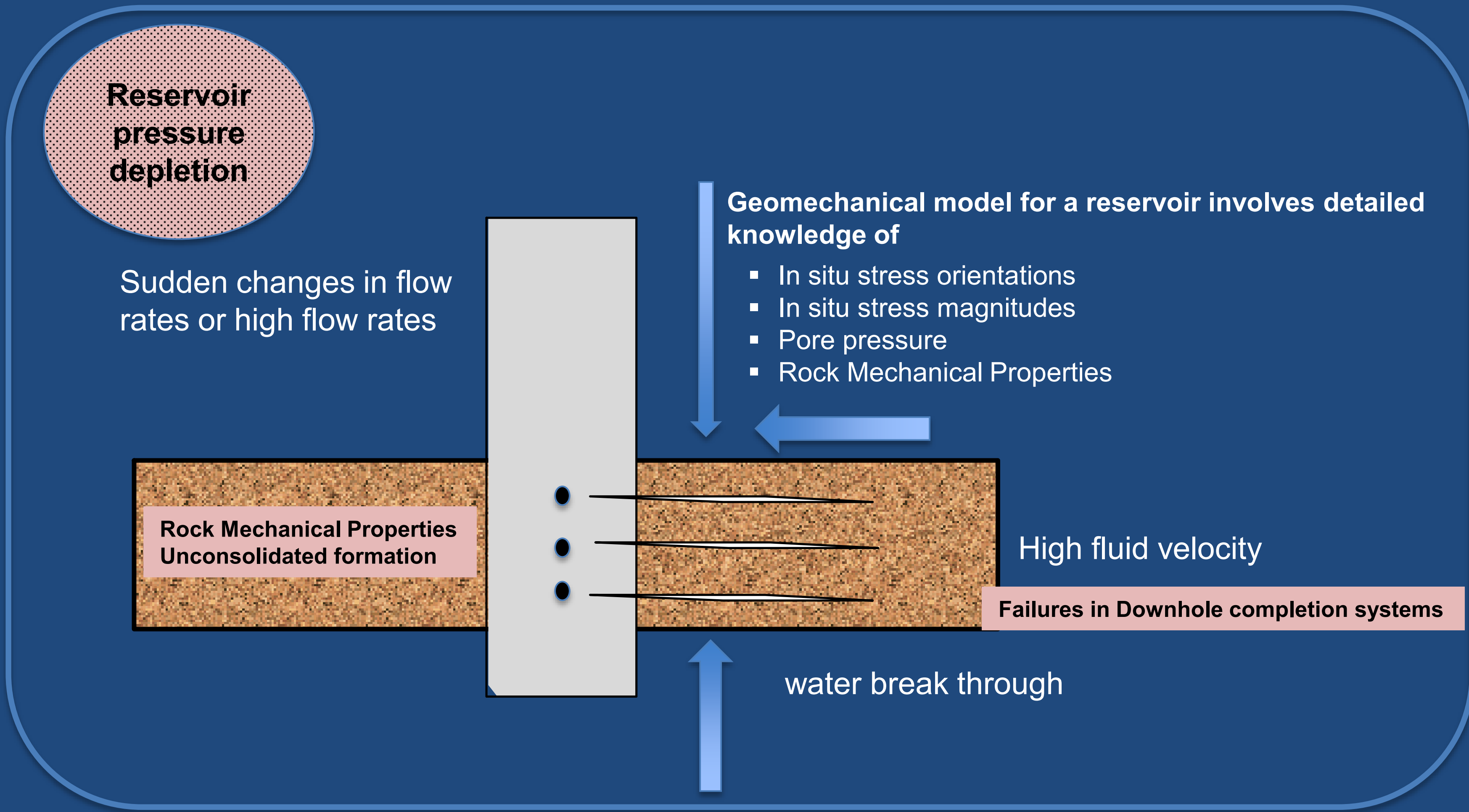
Introduction



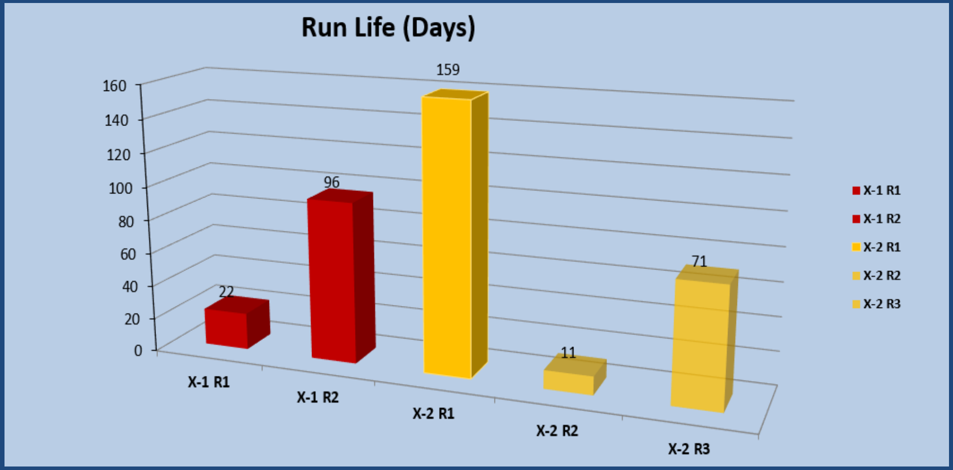
The problems associated with sand production in wells of the Marine Region fields in Mexico have been extensively evaluated through many technical studies: optimal completion analysis for each specific well, geomechanical models to determine premature sand production as well as risk matrices of the well completion and productivity analysis.

<u>This work provides some of the proposed solutions that were executed in wells with running ESP during the well screening and designing in order to mitigate sand production issues based on the well productivity to improve the ESP performance and reliability.</u>

Typical sand problems observed in the field



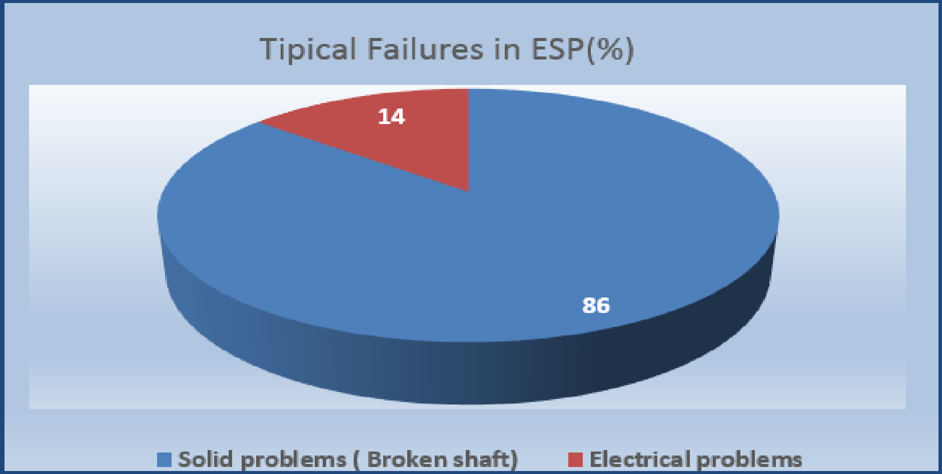
ESP Run life before productivity integral analysis



Generally, any ESP equipment failure in offshore operations is extremely costly.

The production losses and workover cost associated with ESP failures represent a significant impact on any project economics.

The run life of an ESP installed in wells of a Jurassic reservoir used to vary between 2 months (most critical condition) to 8 months (more optimistic application).



Considering one sample: 86% of the failures correspond to broken shafts caused by the accumulation of solids that completely clogged the pumps and the other 14% corresponded to electrical failures.

Productivity, Reservoir and Evaluation for ESP designs

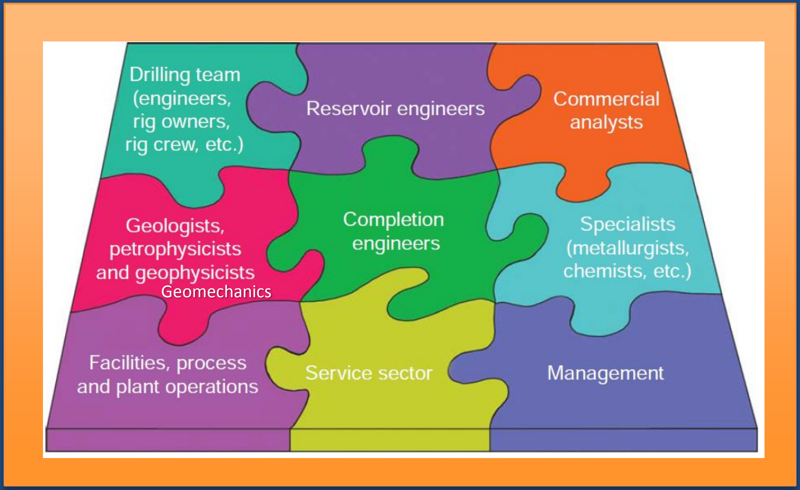
Our goal is to provide customers with an integrated service value combination that will optimize each stage of the process, which includes but not limited to: pump design, implementation, and real-time monitoring in order to analyze production performance. (Multidisciplinary teams GPE-ALS support- Mexican Customers):

	1 VERIFY		2 DESIGN		3 SUPPORT		4 OPTIMIZE
STAGES	Wellbore Model (Set up and Calibration)	Description of well architecture, fluid properties and production capacity (IPR)/ PVT validation, Multiphase Flow)	Detailed Engineered ESP Design	Fully engineered design which takes into account reservoir and fluid properties	Reservoir Simulation Support	Improved accuracy for lift estimation / performance for viscous crude applications	ESP System Sizing and Optimized Configuration
OBJECTIVE	▪ Data gathering, review and analysis ▪ Estimation of well productivity, including production rates		▪ Optimum pump depth ▪ Calculating gas properties and ▪ Pump selection, as well as cable and accessories		Generation of lift curves for various simulators which: ▪ Allows for a wider range of system configurations ▪ Takes into account the heating effect of the pump ▪ Incorporates Baker Hughes' proprietary viscosity correction factors		▪ Carry out nodal analysis ▪ Stress analysis for equipment and casing ▪ Full system testing simulation
ACTION	- Nodal analysis - Accurate modeling of the Artificial Lift system using Baker Hughes' AutographPC™ software		- Sensitivities on pump's operating conditions are carried out on AutographPC™		Provision of a more representative description of the fluid flow in the wellbore, which is required for reservoir simulation		Simulation of different scenarios which may include expected variations in the operating system through the well life.

Improvements in ESP designs and integral solutions

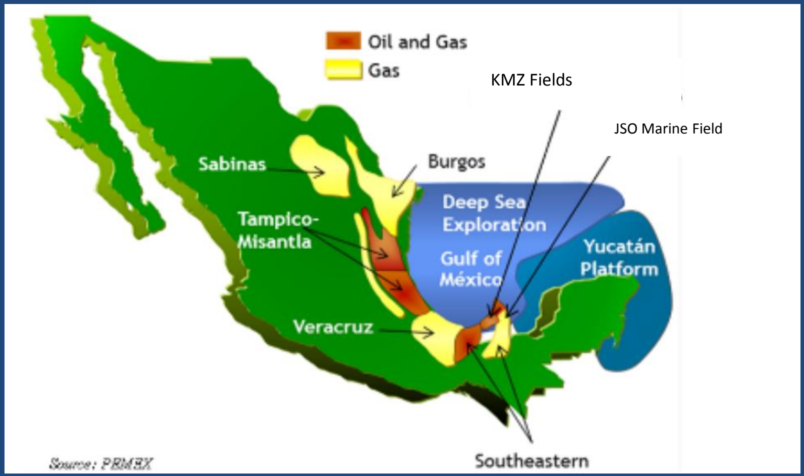
The integral solutions evaluated include:

- Evaluation of the reservoir characteristics, optimal production rates and fluids properties.
- Productivity evaluation / definition of the critical drawdown pressure per well through nodal analysis.
- ESP surveillance, monitoring and diagnosis.
- Analysis of existing wells completion and sand control techniques.
- Improvements in ESP designs like special configuration such as stabilized pumps, mixed flow stages, abrasion resistant materials and others. As well as surveillance techniques, monitoring and wells' diagnosis.
- Improvement of the ESP completion through implementation of downhole tools to separate solids that extend the ESP run life.
- Implementation of corrective cleanings in producing wells through ESP systems.



Reservoir characteristics

Offshore Field – Mexico



Location: Gulf of Mexico (offshore).

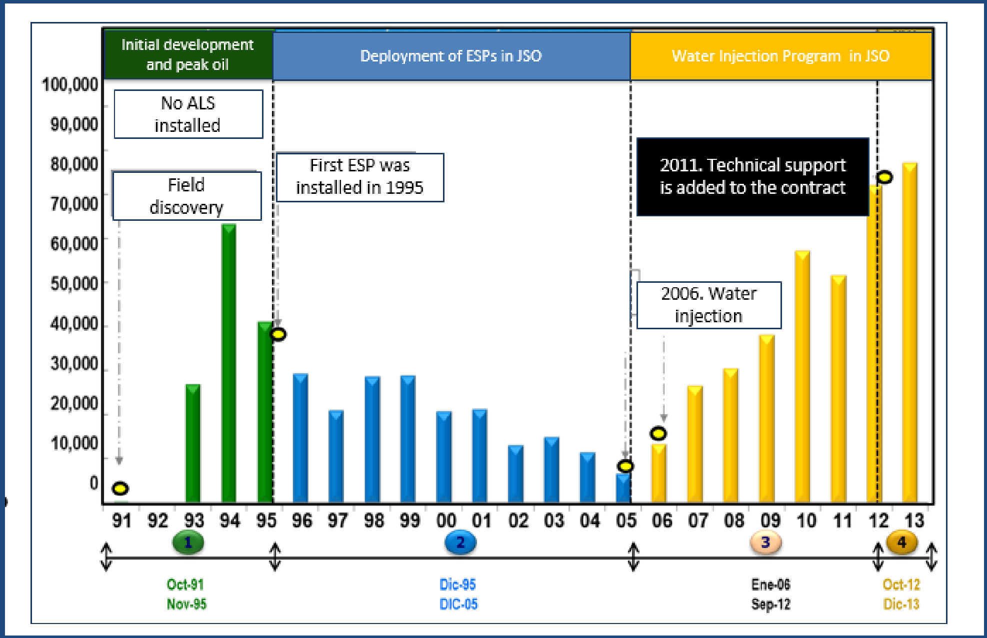
Reservoir Jurassic

Production challenges

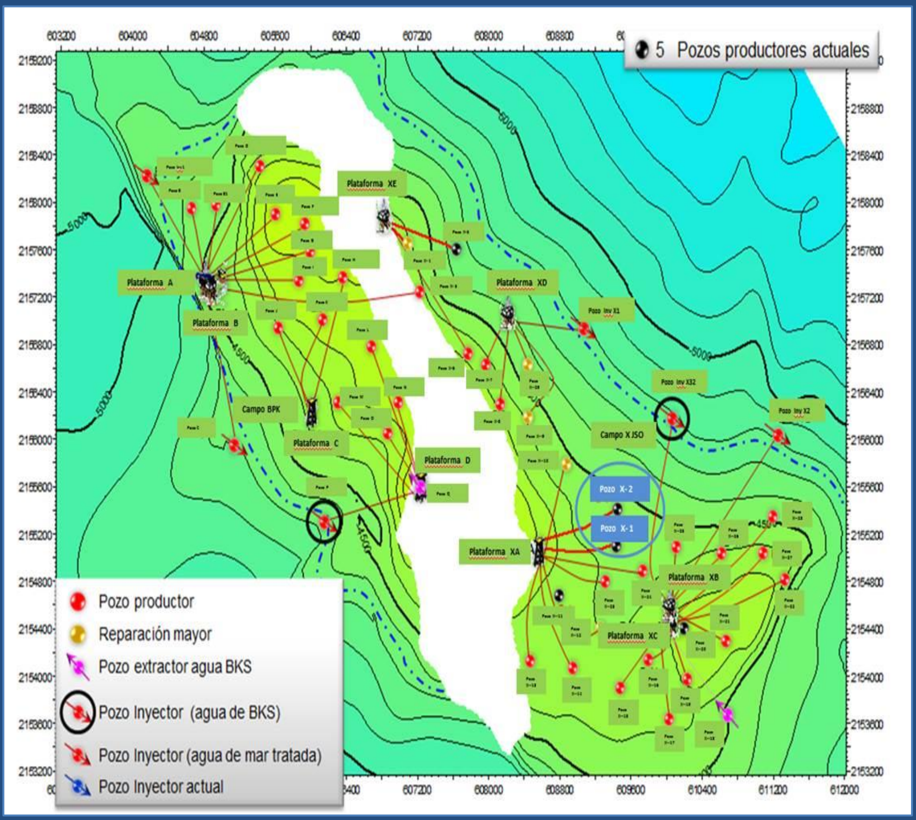
Jurassic Reservoir

- Unconsolidated sandstone
- Low reservoir pressure Lack of pressure support
- Sand production
- Short ESP run lifes (most ESP's failed after operating 5 months or less).
- Decreasing rates due to inefficient lower completion in existing wells : erosion and wear in stand alone, slotted liner, and wire wrapped screen.

Field development since discovery (1991)



Reservoir characteristics



	Description	JSO	Units
Oil exploration	Discovery	1992	Year
	Start of operation	**1993**	**Year**
	Initial reservoir pressure	581	kg/cm^2
	Current reservoir pressure	**220**	**kg/cm^2**
	Temperature	108	°C
Fluids	**Oil Density**	**27**	**°API**
	Viscosity @ Pb	2.04	cp
	Bo @ Pb	1.29	m^3/m^3
	Bubble Pressure	115	kg/cm^2
	Solution Gas oil ratio @ Reservoir condition	52.8	m^3/m^3
	Salinity	250	mppm
Reservoir drive mechanism		Rock Drive Expansion	
JSO Formation	**Reservoir rock lithology**	**Sandstone**	
	Net Thickness	100	m
	Porosity	**22**	**%**
	Water saturation	16	%
	Permeability	**800**	**mD**
	OWC	4,777	mvbnm
Well Status	Drilling	16	quantity
	Producers	**5**	**quantity**
	Injectors	1	quantity
	Closed	3	quantity
	Abandoned	4	quantity

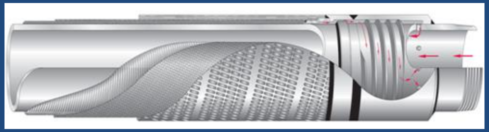
Productivity Evaluation

When dealing with low reservoir pressures, the implementation of ALS can help to increase wells’ productivity by reaching lower flowing pressures.

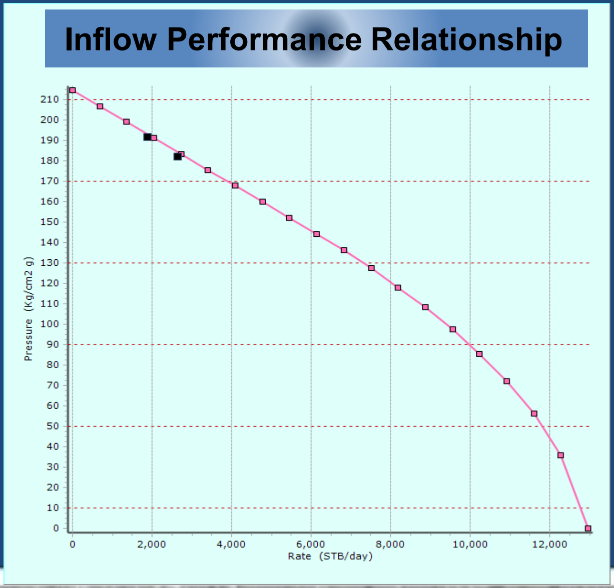
Having an accurate characterization of the fluid properties (o/g/w) and understanding the potential risks associated to sand production, play a crucial role during the design, installation and continuous monitoring of the ALS installed in the well.

Low reservoir pressure and water production

Sand production and fines migration



Reservoir simulation **at a well level** in order to analyze the various completion solutions (ICDs, screens, dual completions) to mitigate sand production and water production.

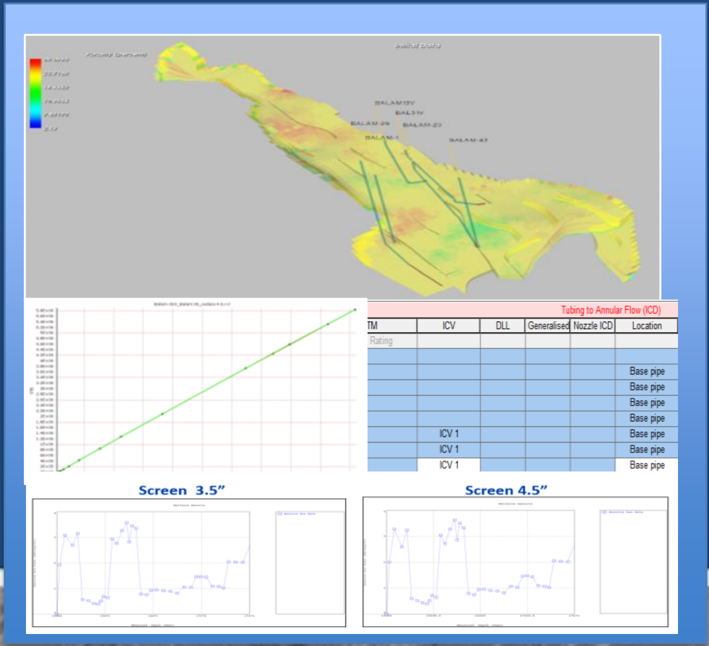


Geomechanical modesl

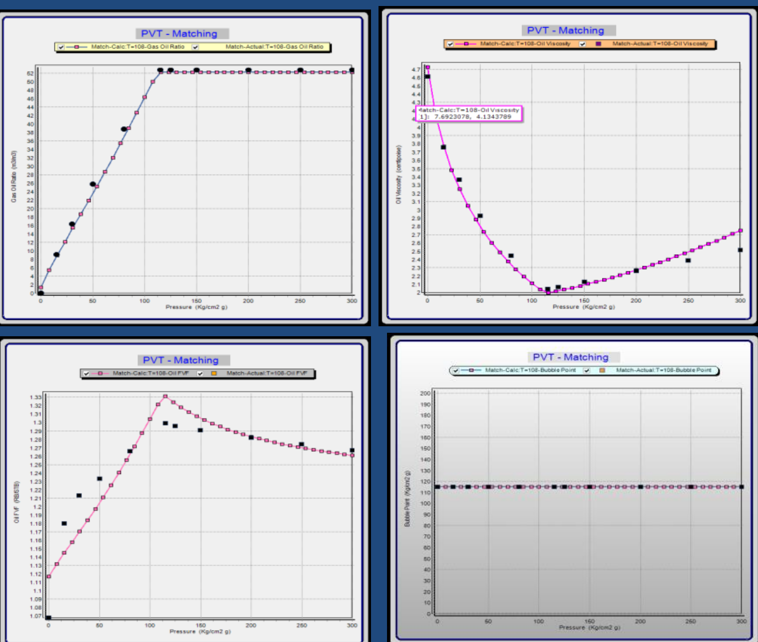
Rock Mechanical Properties from Log Data
Sonic Velocity
3D Models based on wells
(minimum Pwf)

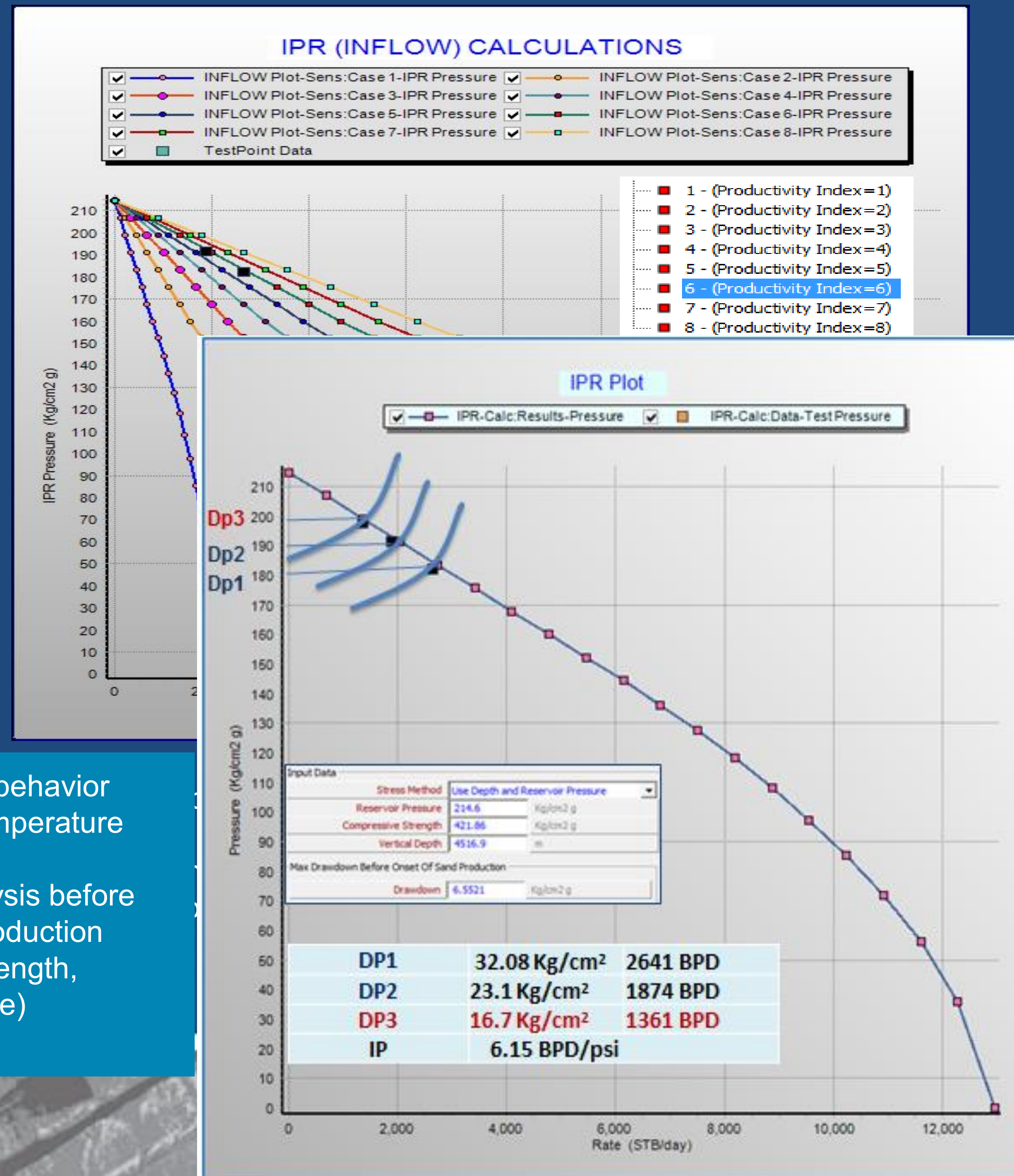
Nodal Analysis
PVT analysis
(Pb, uo, Density ,SARA analysis (asphaltenes)
Water Analysis (incrustations)

Completions
Artificial Lift



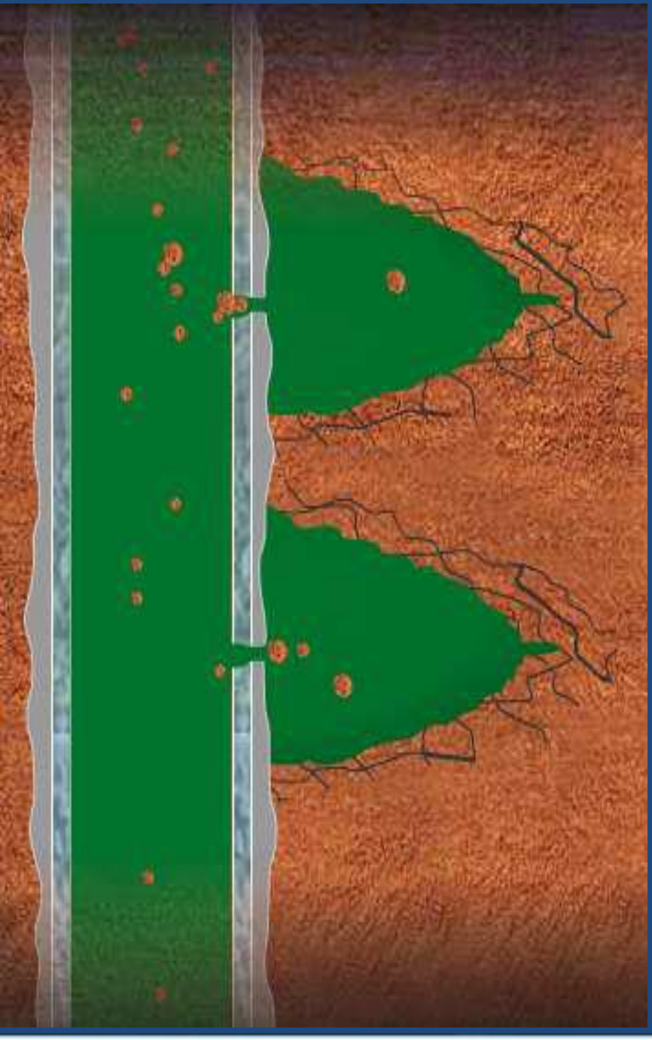
Productivity Evaluation





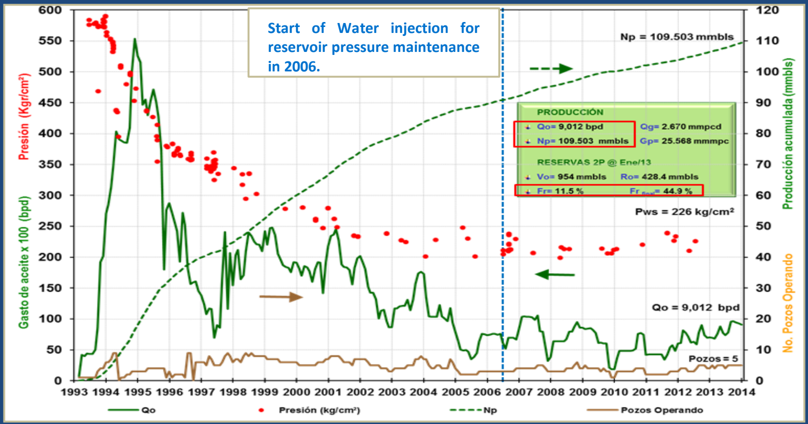
- ❑ PVT analysis and fluids properties calibration
- ❑ Nodal Analysis
- ❑ Productivity Index estimation
- ❑ Sensitivities to reservoir parameters:K, H , Skin, Pws.
- ❑ Flow correlation behavior
- ❑ Pressure and temperature gradient
- ❑ Drawdown analysis before onset of sand production (compressive strength, reservoir pressure)

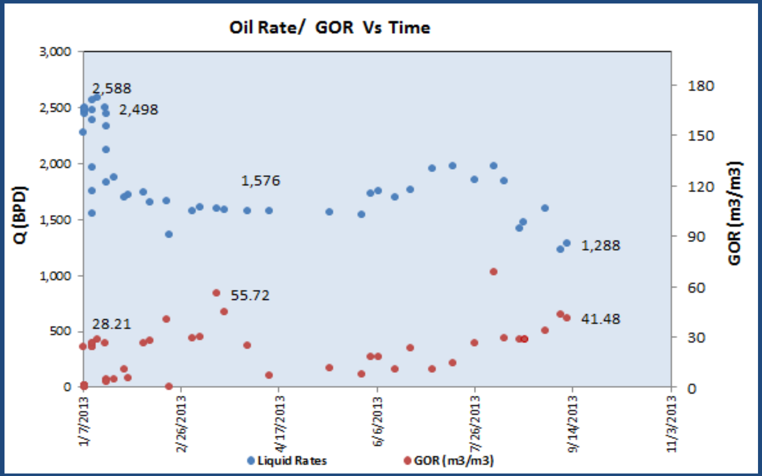
Critical drawdown - Relevant Previous work



- In 2008, the Operator performed a geomechanic study over the JSO reservoir. Mechanical Earth Models were built to provide the major inputs (i.e. UCS: Uniaxial Compressive Strength and Stress directions) for the sand control technique.
- In 2005, the operator performed a geomechanic study in the field to model the fault leakage potential.
    - Critical Drawdown as a function of compressive strength
    - Estimation of Historical drawdown at completion failure
    - <u>Critical drawdown pressure : ~10 -15 Kg/cm2</u>
    - Some wells produce with “no secure” drawdown pressure. Sand production is presented with any drawdown in this reservoir.
    - Some solutions to drain the target area of new wells : Horizontal wells
        - Optimal length of horizontal well (operational efficiency and economic viability)
        - OPTIMAL LENGTH : 600 m to 1000 m
        - Improve solid influx and enhance ESP survivability

Production analysis

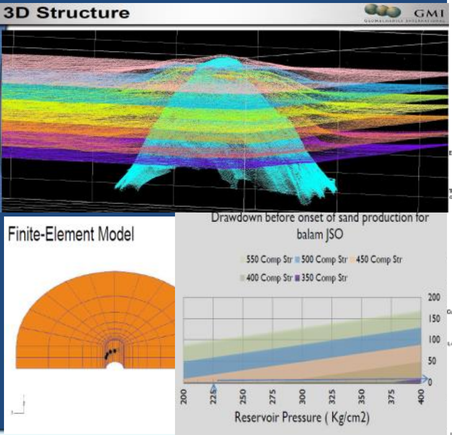


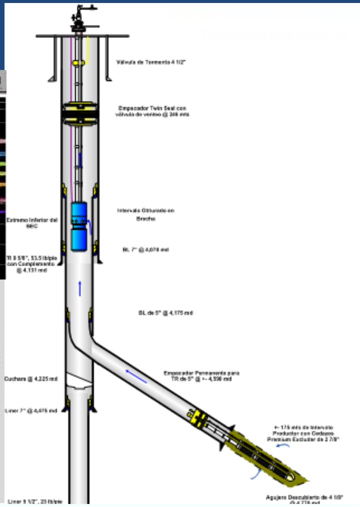


Oil rates scenarios considered Q: 1,300 BPD to 3,000 BPD.

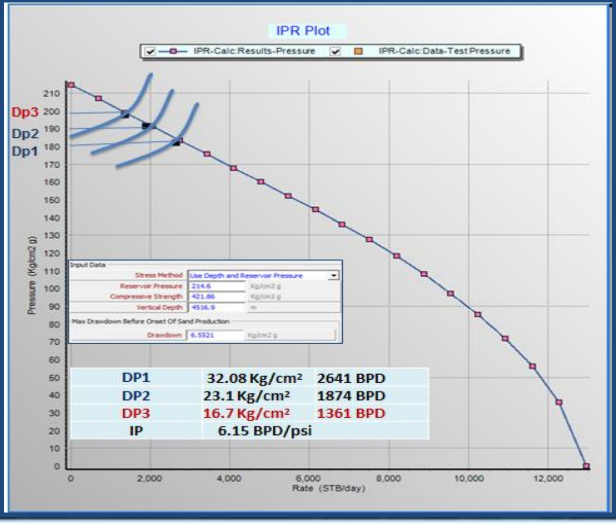
Results with lower drawdown involved fluid rates between 1,300 BPD to 2,000 BPD.

Geomechanical model





Understanding reservoir & well connectivity through Geomechanics

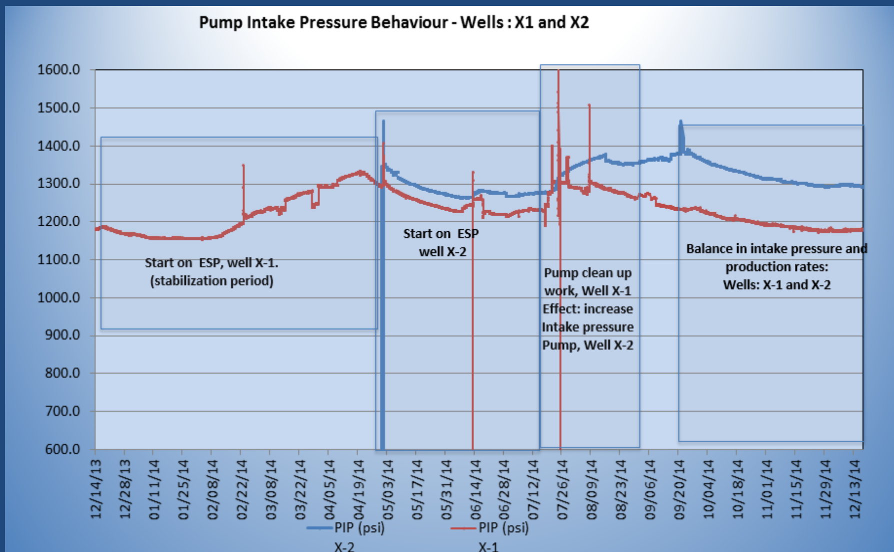


Critical drawdown (Geomechanical Previous work)

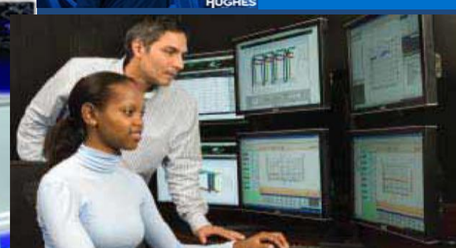
- Simulations indicate that sand is produced with even lower pressure drops than those indicated in the geomechanical studies due to:

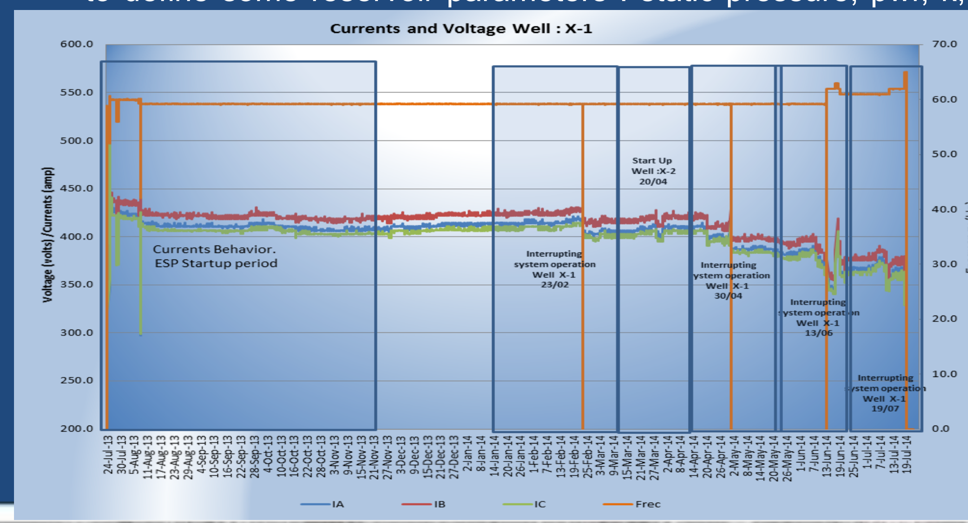
  - Stress conditions in the rock.
  - High depletion in reservoir pressure.
  - Orientation of some wells in the reservoir.
  - Formation damage (non-compatible fluids during the completion and drilling operations).
  - Some mechanical failures in existing wells (eroded screens).

ESP surveillance, monitoring and diagnosis



- Pump surveillance, monitoring and diagnosis through ESP downhole sensor provides valuable information about the ESP and well performance.
- Real time analysis enables teamwork and allows to identify possible effects of the interference between the drainage areas of some wells.
- Through real time ESP monitoring is possible to identify problems in the equipment and potential difficulties in well productivity and reservoirs.
- Data from downhole ESP sensor may be useful in well testing to define some reservoir parameters : static pressure, pwf, k,



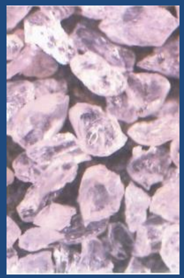


Improvements in ESP designs

ESP systems are not particularly good at handling solids production. The synergic work between our customers and BHGE specialists considered the implementation of the proper technology for severe solids production. BHGE has several options available which will enhance the overall operation of the ESPs in abrasive environments.

How much sand can a pump handle ?

Depends on:



- ❑ Fluid type: light oil, heavy oil, water cut and emulsions.
- ❑ Pump stage configuration.
- ❑ Total liquid flow rates.
- ❑ Characteristics of solids (hardness, acid solubility).
- ❑ Quantity of sand produced, particle size distribution, mineralogy (quantity of quartz) and sand geometry (angularity).
- ❑ Other factors such as carbonates and corrosion.

Consequences of sand production in ESP system

Problem

Solid Production

Effect

Artificial lift system (ESP)

Productivity index

Consequences

- Severe wear of vanes (consequence of: abrasion and erosion - radial & axial)
- Broken shaft (high torque for pump clogging)
- Obstruction of the flow area (impellers)-plugging
- Vibration (affects bearings, mechanical seals, etc.)
- Lower efficiency of pump
- Obstruction of perforated interval due large solids accumulation (damage formation)

Wear of vanes

Broken shaft

Obstruction of pump flow area

What strategy to follow?

Active control

Passive control

Gravel Pack

Screens

Frack Pack

Chemical consolidation

Drawdown control

Selective drilling

Oriented drilling technologies

Handling solids production / ESP

New technologies Implementation

Handling solids production - ESP

You should evaluate

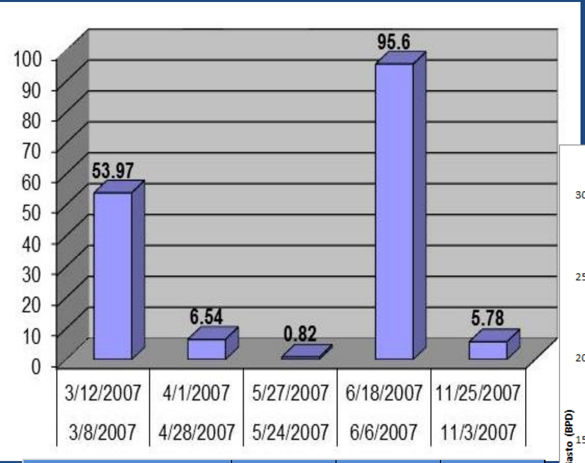
- Costs and Risks
- Productivity and behavior over time
- Reservoir characteristics
- Environmental impact
- Operational Considerations
- Industrial safety

Example of ESP selection and design for a well

<u>Reviewing available information</u>

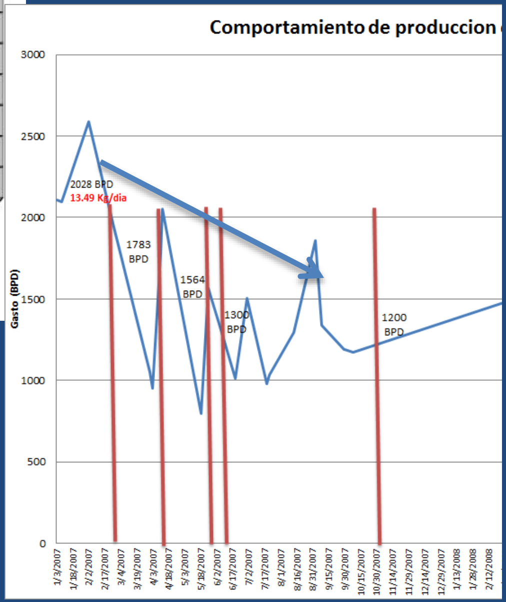
- Production data and historic trends
- History of solids production (non-intrusive device)
- Fluid properties
- Well history: including work-overs, treatments, monthly clean-up operations through ESP systems with HCL -10%, etc.
- Granulometric distribution, composition of solids and geometry.
- Previous ESP run life and failure analysis.

Measurement of surface solids



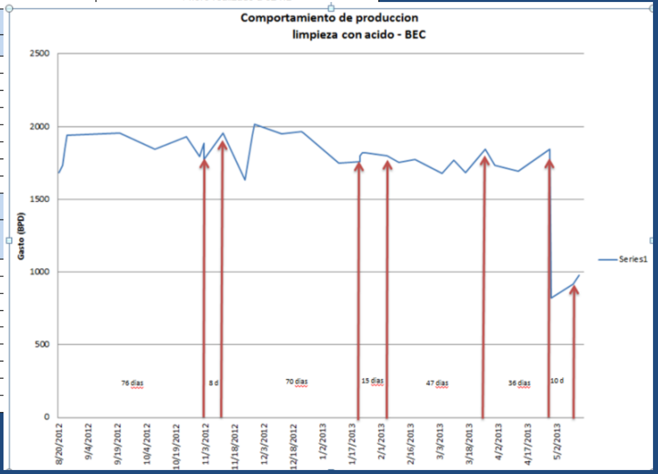
Fecha		Total (Kg)	DIAS	Kg/dia
8/3/2007	12/3/2007	53.97	4	13.49
28/04/2007	1/4/2007	6.54	27	0.24
24/05/2007	27/05/2007	0.82	3	0.27
6/6/2007	18/06/2007	95.6	12	7.97
3/11/2007	25/11/2007	5.78	22	0.26

Well production behavior



Statistic of cleaning interventions (perforations and pump)

Fecha Actualización	Ql bbls/d	Tiempo entre limpiezas (dias)	Observación
5/14/2013 10:23	977		Frec. 62 Hertz, afoo despues de limpieza de Eq.BEC
5/11/2013 20:01	920		Aforo después de la limpieza del equipo BEC.
5/1/2013 17:58	822	10	A 62 Hz (Después de una estimulación con 5m3 de ácido)
4/28/2013 18:28	1,847.00		A 62 Hz
4/15/2013 10:23	1,692.00		Aforo realizado a 62 Hz
4/8/2013 13:53	1,735.00		Aforo realizado con 62 Hz
3/26/2013 11:35	1,843.00	36	Aforo a 62 Hz, después del tratamiento de limpieza por EA
3/21/2013 9:00	1,684.00		Aforo realizado a 62 Hz
3/12/2013 9:25	1,771.20		Aforo realizado a 62 Hz
3/6/2013 10:06	1,676.00		Aforo realizado a 62 Hz
2/24/2013 11:49	1,776.00		Frecuencia 62 hz
2/18/2013 21:17	1,753.20		Aforo realizado a 62 Hz
2/7/2013 16:31	1,797.80	47	Aforo realizado a 62 Hz, después de la limpieza con ácido en directa por TP
1/25/2013 16:53	1,821.00		Aforo realizado a 62 Hz
1/23/2013 12:41	1,817.00		
1/23/2013 12:38	1,761.00		
1/23/2013 12:36	1,797.00		
1/12/2013 12:53	1,747.20		
12/23/2012 18:37	1,953.00		
12/31/2012 8:03	1,964.60		
12/12/2012 20:46	1,950.20		
12/1/2012 19:35	2,016.00		
12/1/2012 19:35	1,941.00		
12/1/2012 19:35	1,631.00		
11/13/2012 8:37	1,958.00		
11/5/2012 12:23	1,886.00		
11/5/2012 12:22	1,773.00		
10/31/2012 12:53	1,796.00		
10/31/2012 11:35	1,928.00		
10/14/2012 19:03	1,845.00		
9/24/2012 18:16	1,954.20		
8/24/2012 19:06	1,942.50		
8/24/2012 8:10	1,846.10		
8/22/2012 21:11	1,734.70		
8/21/2012 7:12	1,681.90		



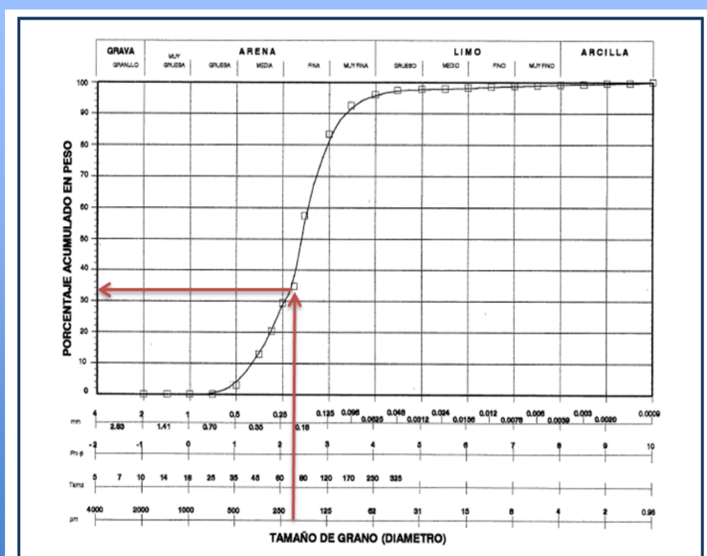
- **Reduction in well production (decreasing from 2000 BPD to 1200 BPD).**
- **Excessive sand production in wells with high liquid flowrates (1800 BPD -2500 BPD ---- Sand volume : 13.49 kg/day).**
- **Well Monthly interventions : Pumps Clean up (tubing or annular) (10% HCL) .**

Quantity of sand that falls to the bottom of the well (production interval) and quantity of sand passing through the pump.

- It is necessary to know granulometry of the rock (grain size probability curve).
- With granulometry information and the maximum suspension diameter (Robinson equation).
- Suspension diameter : 225 microns (analysis made in Mexico ESP case Study).

Results indicate : Approximately 68% of the particles will be handled by the pump. Fraction of surface solids is 56.91 ppm.

Granulometric distribution curve (core sample JSO – 4445.8 m)



Conclusion: There is 68% probability to find grains with this particle diameter ≤ 225 microns.

When the fluid and sand properties are known, equation of Robinson allows to determine the widest diameter that can be transported to the surface for a given liquid rate (Q = Velocity * Area).

$$D_{MAX} = \sqrt{\frac{V * 18 * \mu}{g * (\rho_{arena} - \rho_{liq})}}$$

Considering:
Q = 1800 BPD, bottom viscosity 0.32 cP @ 200 ° F, casing 7¾ inches x 46.1lb / ft.

D suspension particles = 225 microns.

Particles with diameters less than 225 microns are dragged through the pump (according to the equation) and any particle bigger than 225 microns fall at the bottom of the well.

Geometry and composition of grains

FIGURA No. 9

PROFUNDIDAD: 4445.84 m
NUCLEO: 7

ANALISIS GRANULOMETRICO:

% PESO ACUMULADO	UNIDADES PHI
5	1.03
16	1 60
25	1.88
50	2 40
75	2.83
84	3 03
95	3 84

TAMAÑO DE GRANO: 2 34 (0.20 mm)

ESCOGIMIENTO (phi): 0 78 MODERADO

ASIMETRIA (phi): -0 03 SIMETRICA

ANGULOSIDAD (phi): 1.22 ANGULOSA

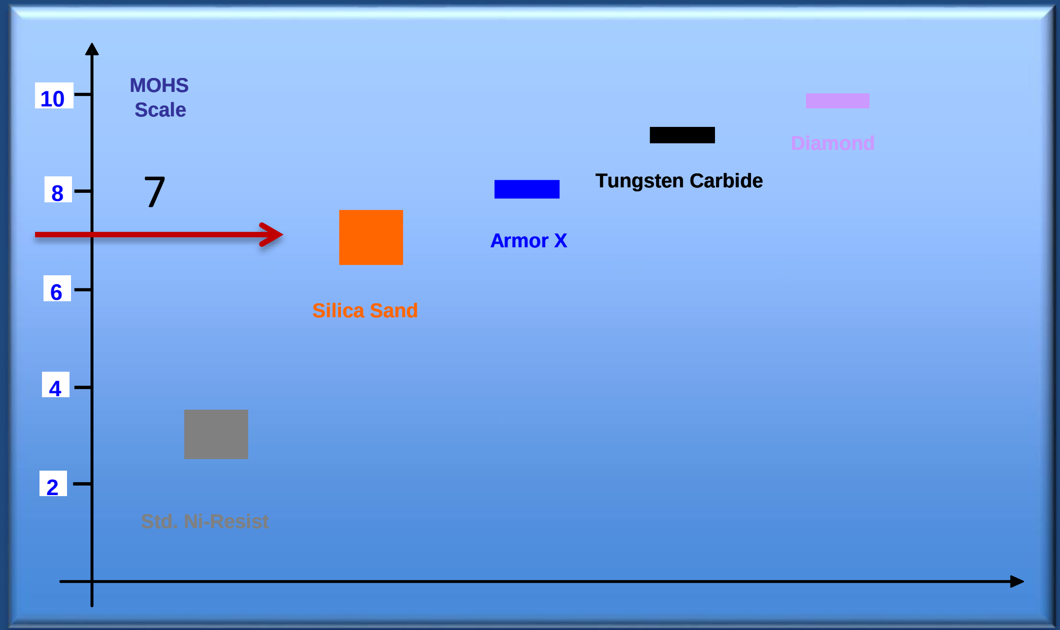
TAMIZ No	MICRONES	UNIDADES PHI	PESO RETENIDO	PESO ACUMULADO	% PESO RETENIDO	% PESO ACUMULADO
10	2000	-1.00	0.00	0.00	0 00	0.00
14	1400	-0 49	0.00	0.00	0 00	0.00
18	1000	0 00	0.00	0 00	0 00	0 00
25	710	0.49	0.00	0.00	0.00	0 00
35	500	1 00	0 90	0.90	3.00	3.00
45	355	1 49	3.00	3.90	10.00	13.00
50	300	1 76	2.20	6.10	7 33	20.33
60	250	2.00	2 70	8.80	9.00	29 33
70	212	2 25	1 60	10 40	5.33	34 67
80	180	2.47	6.80	17 20	22.68	57.34
	125	3.00	7 81	25.01	26 03	83.37
	90	3 47	2 76	27.77	9.19	92 56
	63	3 99	1 03	28 80	3.44	96 00
	45	4.47	0.42	29 21	1 39	97 38
	32	5 00	0.11	29.32	0.36	97.74
	24	5 50	0 05	29.37	0 15	97.90
	16	6.00	0.09	29 46	0 31	98.20
	12	6.50	0.11	29 57	0 36	98.56
	8	7 00	0.05	29.62	0.15	98 72
	6	7.50	0.09	29.71	0 31	99.02
	4	8 00	0.05	29.75	0.15	99 18
	3	8 50	0 05	29 80	0 15	99 33
	2	9.00	0 08	29.88	0.26	99.59
	1 5	9.50	0.03	29.91	0 10	99.69
	1	10.00	0.09	30.00	0 31	100.00
	<1	>10	0 00	30.00	0.00	100.00

- ❑ 38% CLAYS,
- ❑ 62% QUARTZ
- ❑ (SILICA - HARDNESS: 7 SCALE MOHS)

To determine Material Recommendation Index (MRI) and to select the proper type of abrasive protection and pump configuration, the following information is needed:

- ❑ Volume of solids handled by the pump :56.91 ppp
- ❑ Particle diameter: D particle ≤ 225 microns
- ❑ Composition/ mineralogy : 38 clays and 62 quartz
- ❑ Hardness of the grains: 7 Mohs

•Light	< 10 mg/liter
•Moderate	11 - 50 mg/liter
•Heavy	51 - 200 mg/liter
•Severe	>200 mg/liter



Improvements in ESP designs

1. Mixed flow stages with radial and axial stabilization every three stages (tungsten carbide bushings). Stages made of abrasion-resistant material (Ni-Resist) SSD type.

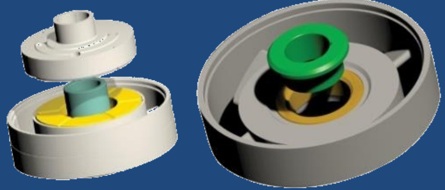
2. Stages with larger flow area to avoid clogging and stuck stages. (lower erosional velocity which reduces wearing and vibration)

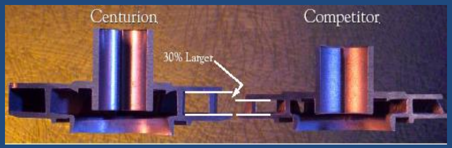
3. Diffuser includes rotary suppressor flaps to reduce damage in pump stages and avoid possible mechanicals failures in housing.

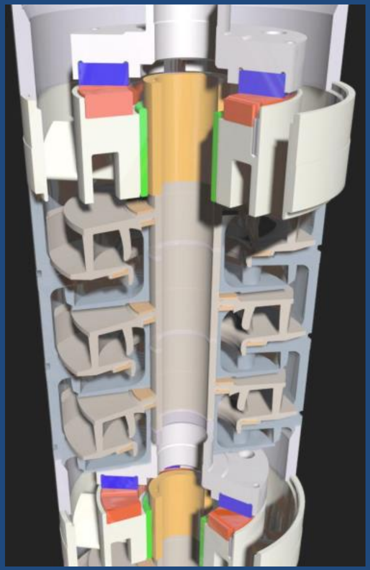
4. Pumps with extended operating ranges that adapt to changing well conditions as production rates change, providing operational flexibility ideally for this reservoir types in which the production index declines rapidly due to the accumulation of solids in the perforated interval.

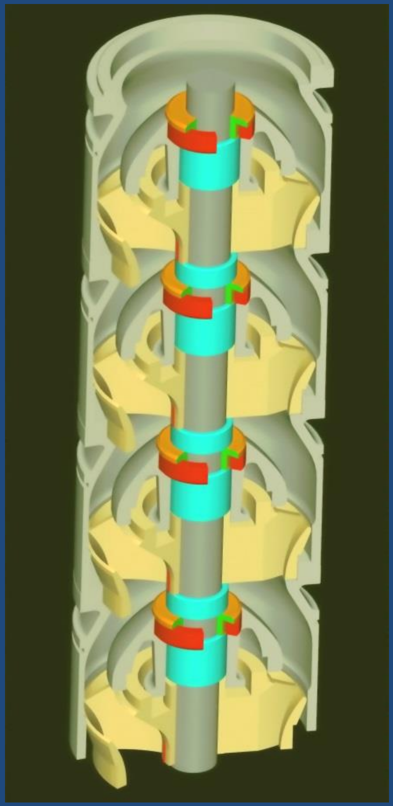
5. Pump geometry generates higher lift per stage, requiring fewer stages than conventional or radial pumps (less mechanical complexity). Wider stage vane openings reduce pump plugging and give ESP systems enhanced solids and gas-handling capabilities.

6. The Monel shaft material was replaced with Inconel material for a better resistance under plugged and over-torque events.

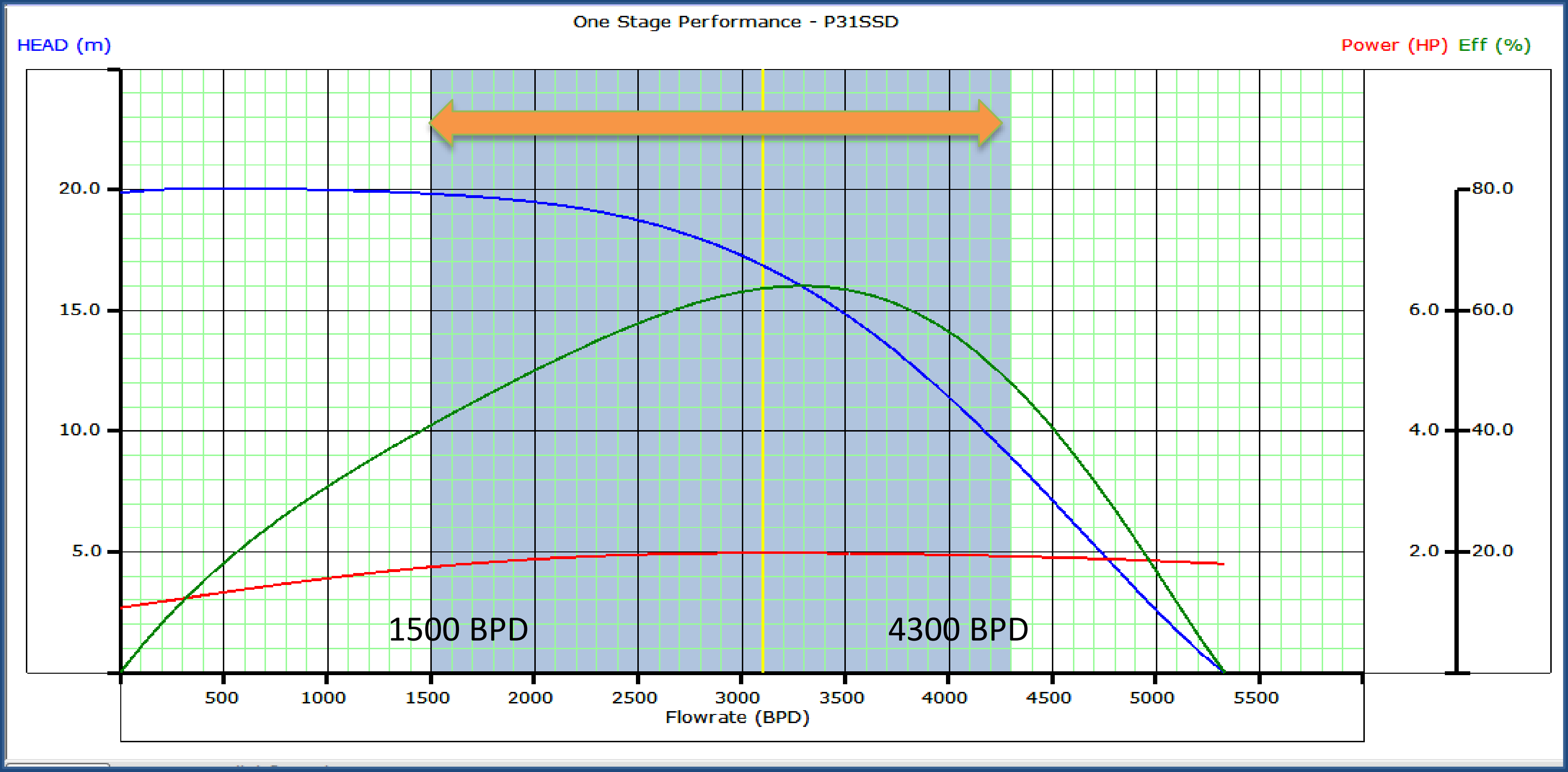




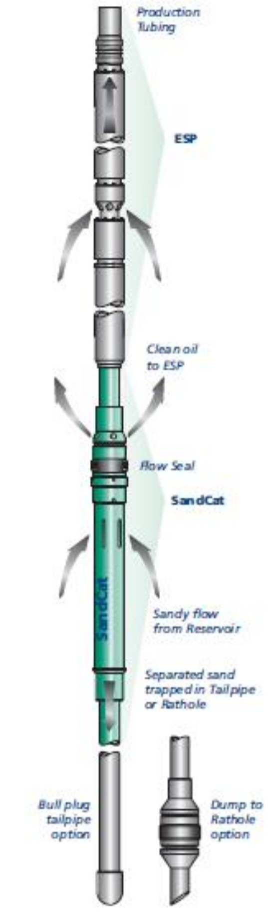




The pump allows a wider operating range that offers a higher operational flexibility which is needed in this type of sandstone reservoir, where the well production declines are too high due to the gradual solids accumulation in the production interval.



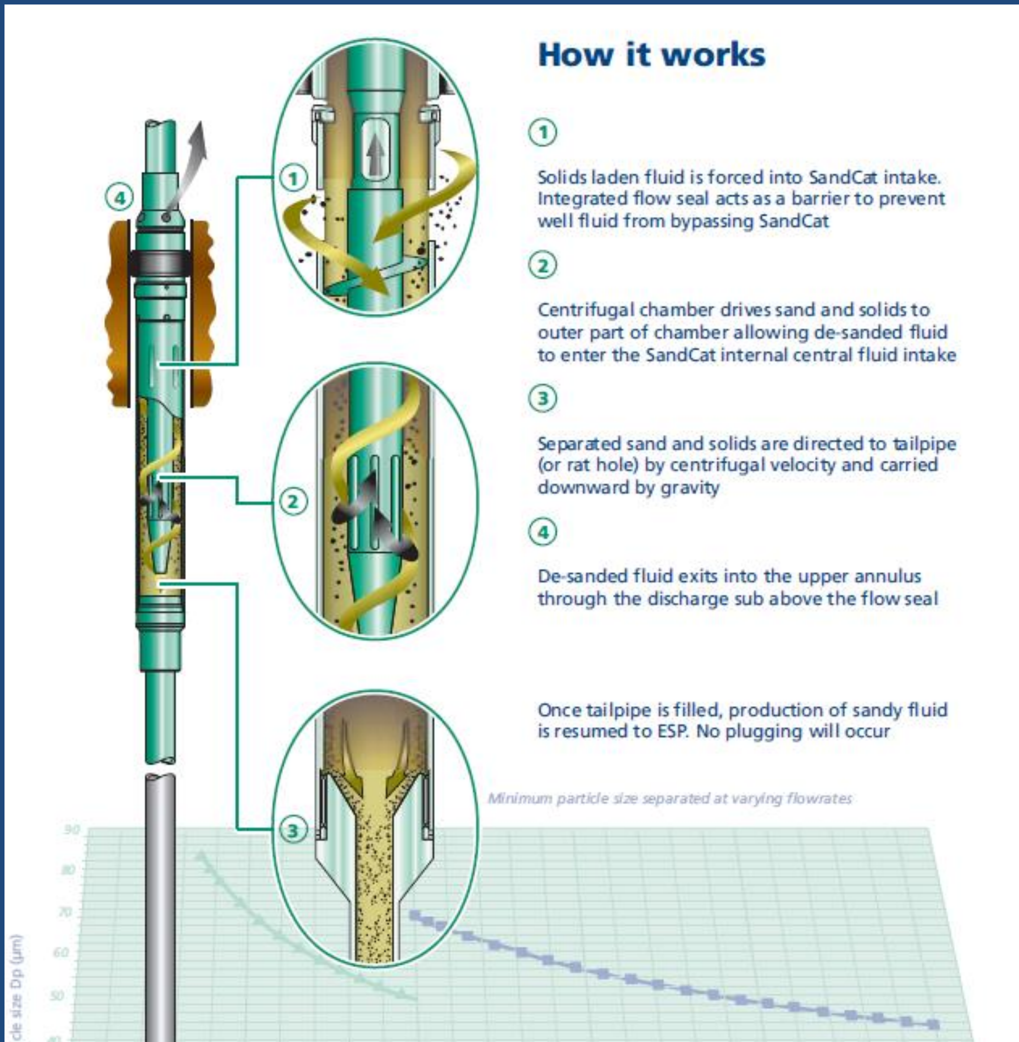
Improvement in ESP completion through downhole tools to separate solids and extend ESP run life



Downhole Sand separator is designed to separate the sand from the produced fluid before it enters the pump. This device is attached below the ESP motor (base of the motor). The sand separator has no moving parts. The process of separation is done by centrifugal forces generated by the velocity of the fluids in the helicoidally section of the device.

The sizing of the ESP system with the downhole sand separator was the first application tested in wells from Marine Region of Mexico.

The obtained results and the low capital cost of the solution made it possible to standardize the application and use the tool with an ESP for every well in the field.



Downhole Sand Separator

Key Features

- Separates sand particles of 40 Microns and above.
- No well preparation required- RIH with ESP.
- No moving parts.
- Assists gas separation.
- Low capital cost.
- The sand management system if offered for different types of sand.
- Collection options.

Casing Size	Solid separator OD	Flow rate	Overall Length
5-1/2"	4"	200-1000 bbd 400-1300 bbd 1000-1700 bbd 1200-2000 bbd	112.7" 118.7" 121.7" 123.5"
7"	5-1/2"	200-1000 bbd 1000-2200 bbd 1500-2800 bbd 1800-3600 bbd 2500-5000 bbd	114.5" 125.7" 140.7" 148.7" 165.7"

Improvement in ESP completions (Downhole Sand Separator)

Sizing of Pipe storage

Solids Separator

Estimation of sand volume produced (sand to be stored in the downhole pipe) in order to calculate filling time of the storage pipe (consider pipe diameter).

Well geometry

Desired production rate

Limitations of the motor sensor connection (maximum weight supported :pipe + wet sand)

General Steps:

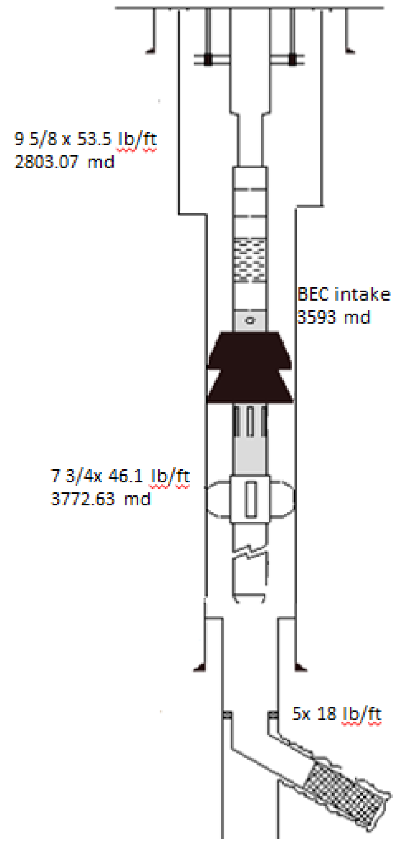
- With the desired production and well geometry, the separator model was selected (expected production ranges between 1200 BPD to 2000 BPD).
- Another factor to be considered for the design of the separator involved the volume of produced sand.
- The case study considers the most critical solid production rates for a well. The design takes into account the new expected liquid production rate: 1800 BPD and the surface solids measurements : 13.49 kg/day This evaluation estimated a surface fraction of solids :56.91 ppm.

Well	Daily Volume of Sand (not compacted)		Sand height in camera per day		Filling time Chamber of accumulation
	ft3/d	m3/d	ft/d	m/d	días
X-1	10.02	0.28	0.93	0.3537	122

Final Sand Separator Configuration

Definition of the length “pipe tail“ depends on : maximum weight supported by the motor sensor connection (In this case is 16,602 Lbs) . This arrangement considers a pipe length of 137 meters (Tubing 3 ½ inch).

The total weight is 7,930 Lbs (weight of the solid separator + pipe tail saturated with wet sand).



Tubing chamber	3 ½” x 9.2 Lb/ft
Tubing area (m2)	0.00476
Length (m)	137
Volume (m3)	0.6534

Equipment	Weight (Lb)
Cross over	25
Packer	80
Solids separator	65
Solid accumulation chamber (considering wet sand)- 137 m	7760
Total weight (Lb)	**7930**

Conclusion

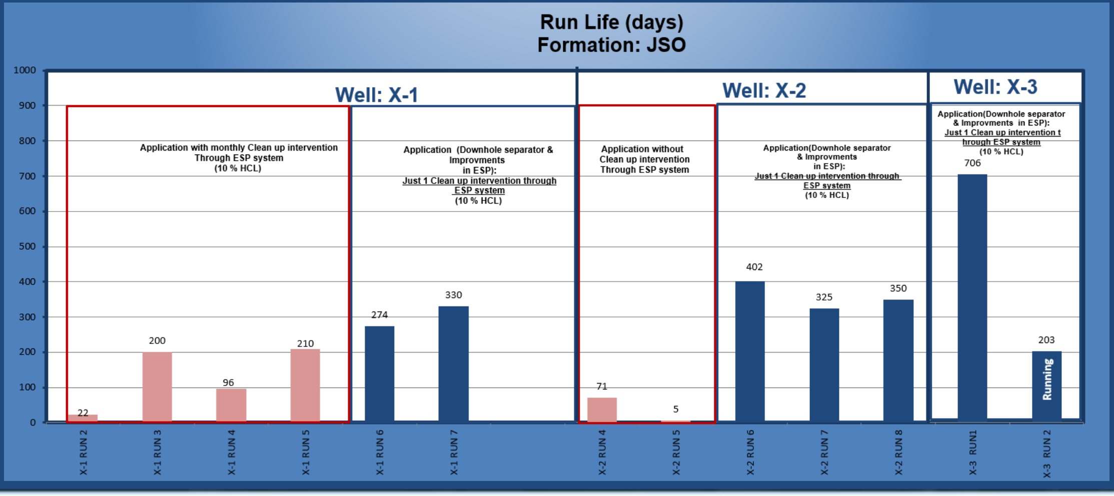
- Improvement in ESP run life (Uninterrupted operation without well intervention for clean-ups through the ESP systems), reduction of drilling costs: 14.4 MMUDS/year (reduction of 6 interventions) and savings of 2.5 MMUDS associated with less well interventions for cleaning up through the pumps.

- Uninterrupted production per well : 2000 BPD during 12 months and more.

- Significant reduction of risks for ESP systems avoiding too many intervention for well cleaning up. (ESP equipment less exposed to chemicals .

- Update geomchanical model considering current reservoir conditions, reduction of pore pressure (continues increase in mechanical stress) and changes in Wells drawdown (inadequate drag forces).

- Conservative production rates per well, considering critical drawdown



Thank you for your attention

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The authors are grateful for the collaboration of the operating company and the multidisciplinary work made it with them, special thanks to the well productivity area and team and the VCD engineering team.

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