Appalachian Basin
Gas Well Deliquification Seminar

Marietta College

Marietta, Ohio

June 4 – 6, 2012

Plunger Lift
Optimize and Troubleshoot

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CONTENTS

- ❑ **Optimized ?**
- ❑ **Optimize a single well**
- ❑ **Optimize many wells**

PRIMARY PURPOSE

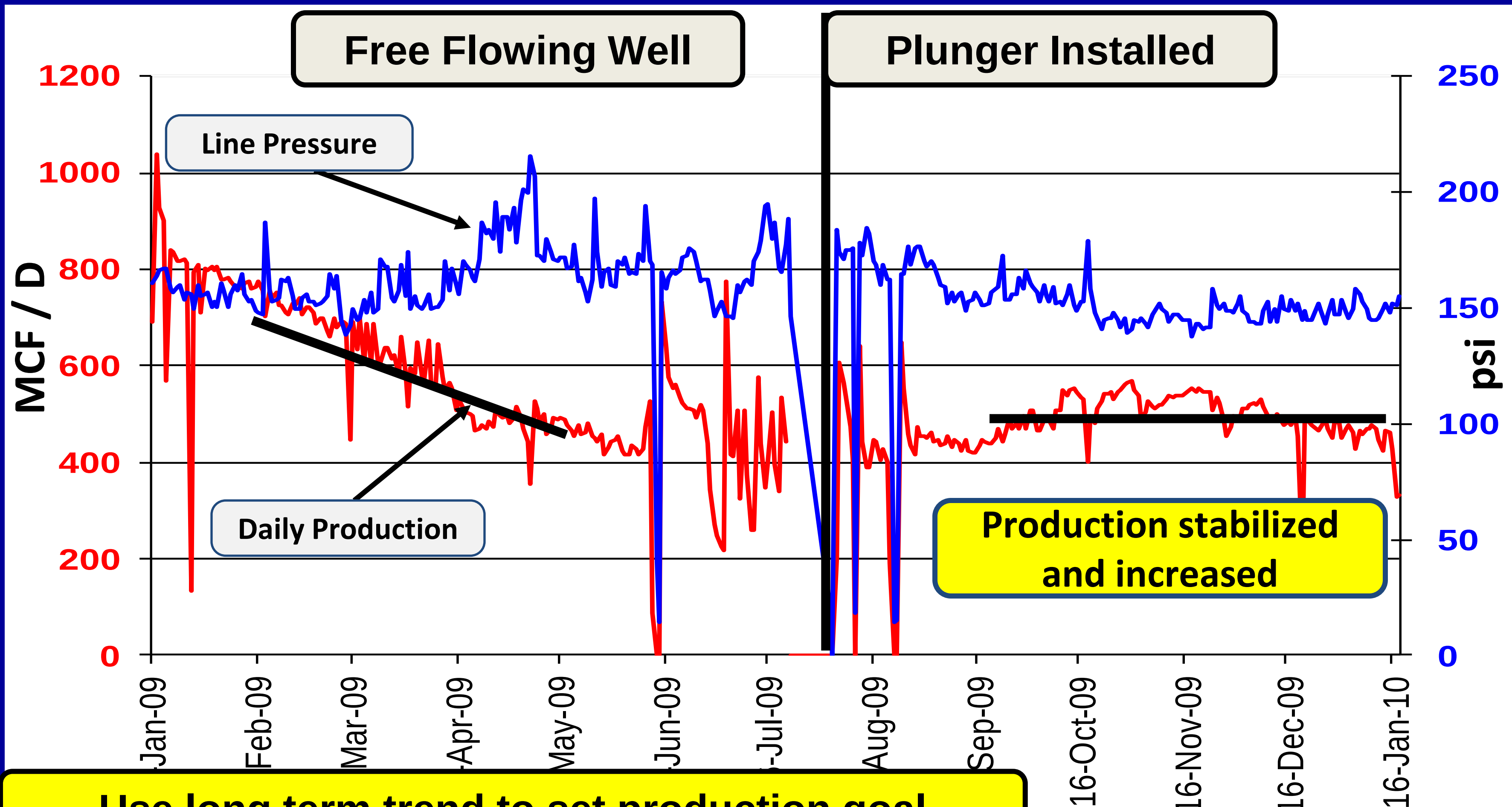
Remove liquid from the tubing so gas can flow freely to the surface

GOAL

OPTIMIZED

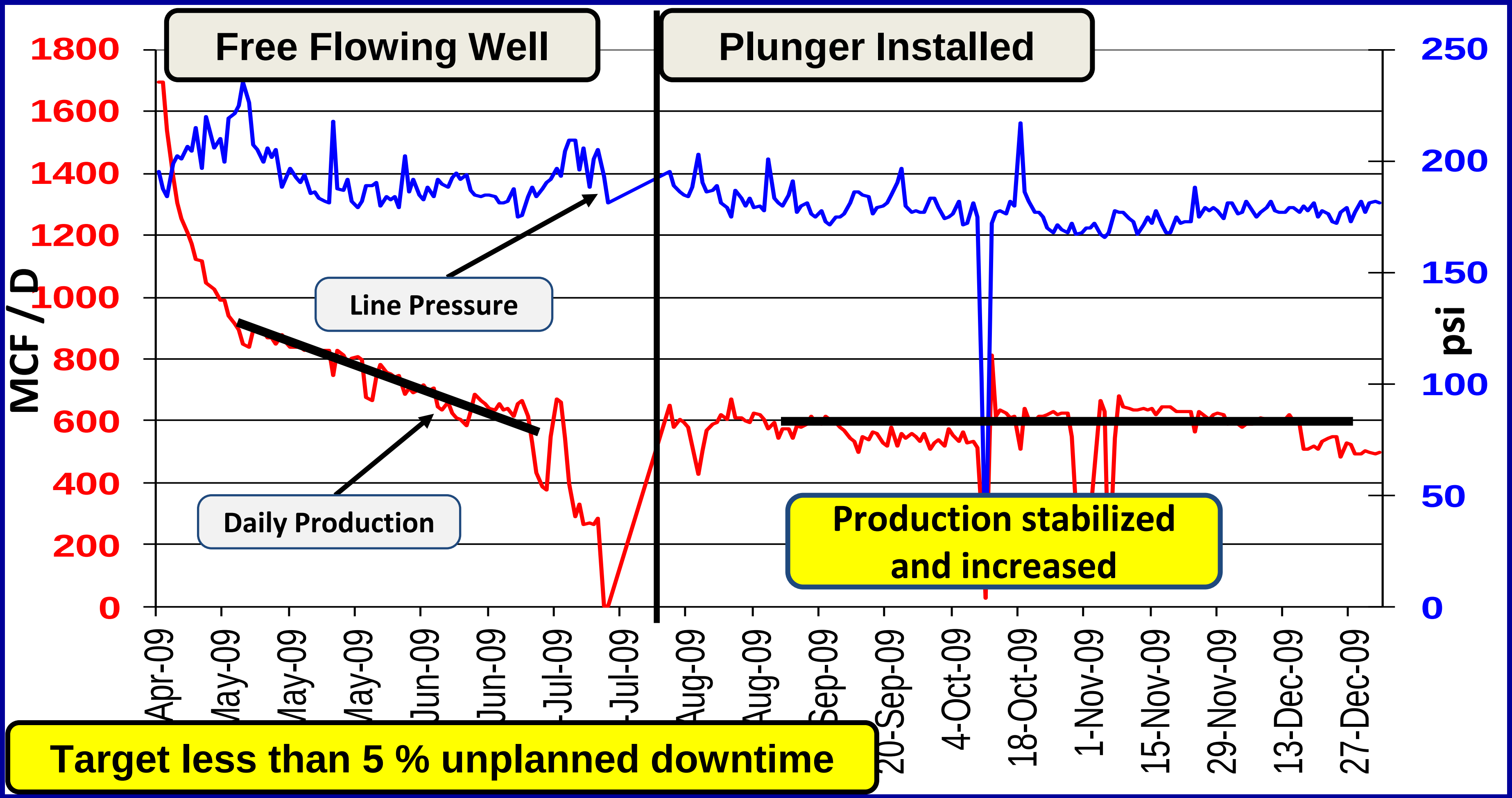
- ✓ 70 % or more of AOF
- ✓ On original decline curve

GOAL



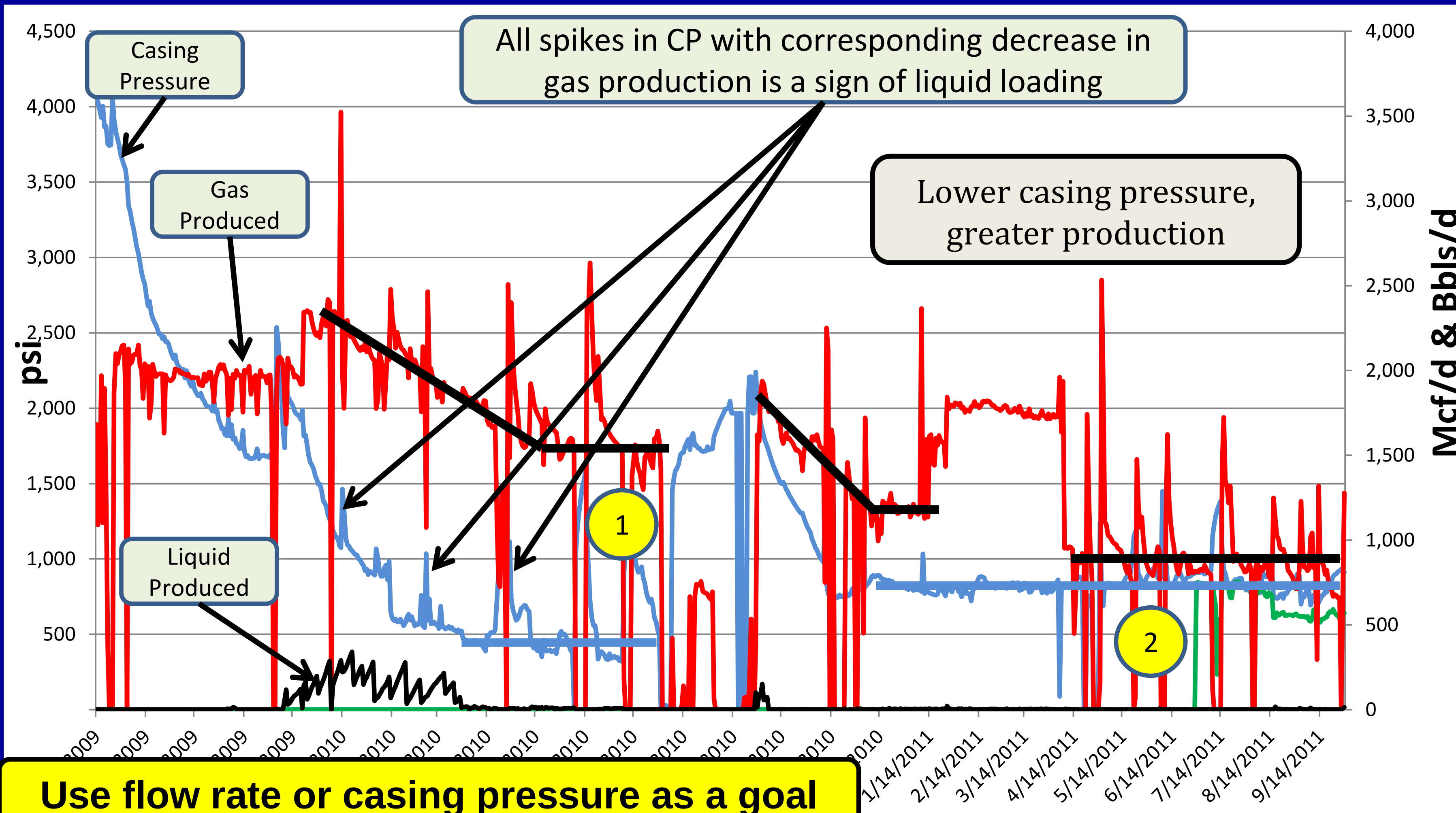
Use long term trend to set production goal

GOAL



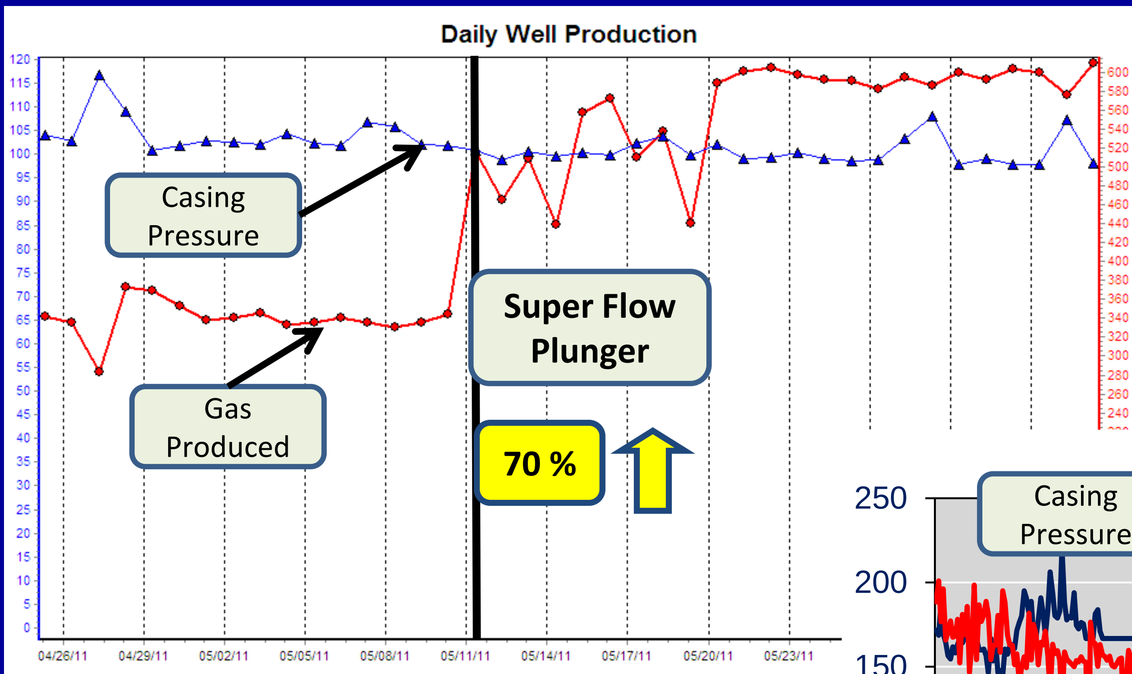
Free Flowing Well
Plunger Installed
MCF / D
psi
1800
1600
1400
1200
1000
800
600
400
200
0
250
200
150
100
50
0
Line Pressure
Daily Production
Production stabilized and increased
Apr-09
May-09
May-09
May-09
Jun-09
Jun-09
Jul-09
Jul-09
Aug-09
Aug-09
Sep-09
20-Sep-09
4-Oct-09
18-Oct-09
1-Nov-09
15-Nov-09
29-Nov-09
13-Dec-09
27-Dec-09
Target less than 5 % unplanned downtime

GOAL

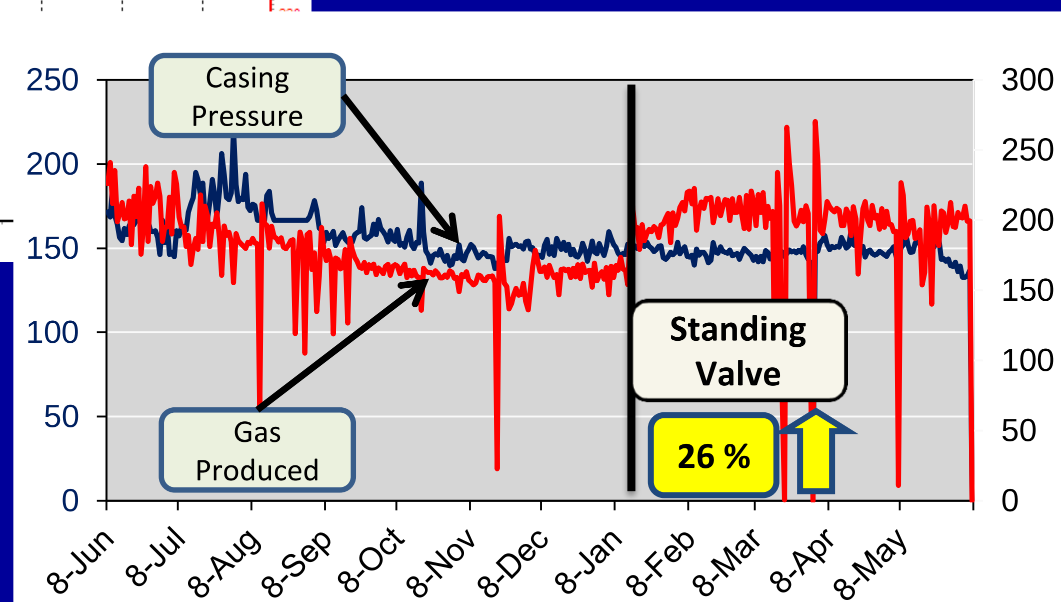


Use flow rate or casing pressure as a goal

GOAL

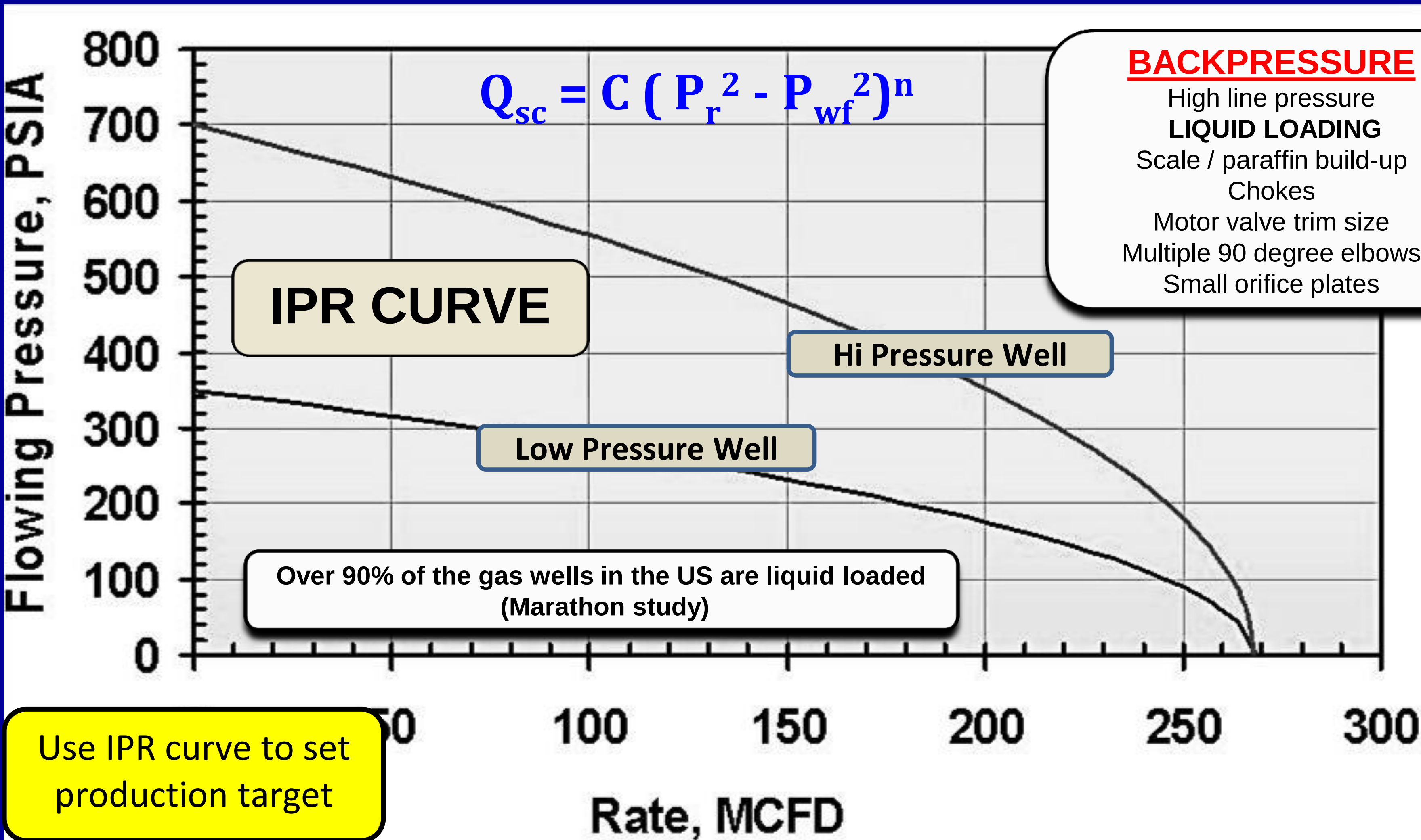


Production goals or trial and error?



Set a production target for each well!

GOAL

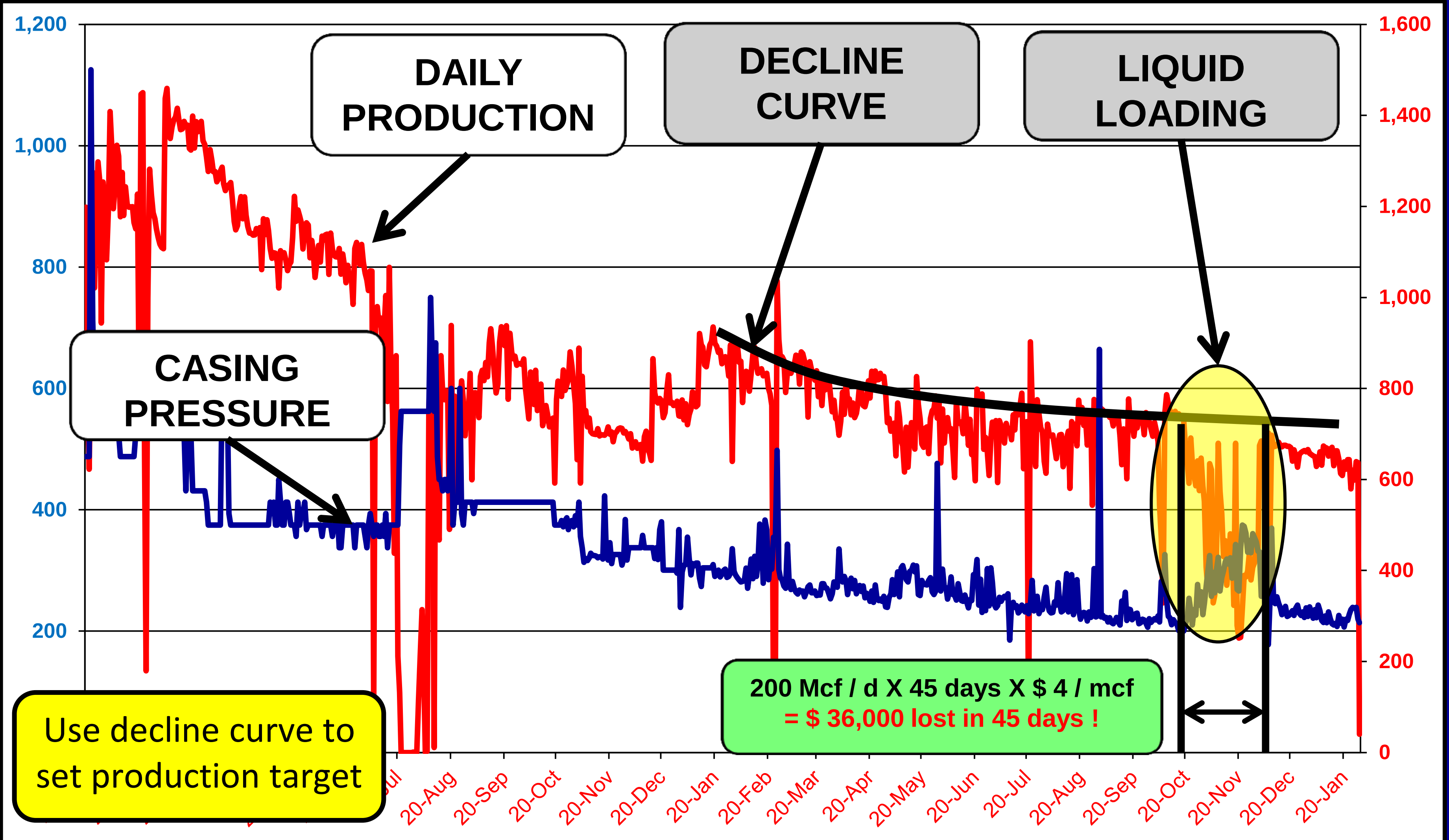


BACKPRESSURE

High line pressure
LIQUID LOADING
Scale / paraffin build-up
Chokes
Motor valve trim size
Multiple 90 degree elbows
Small orifice plates

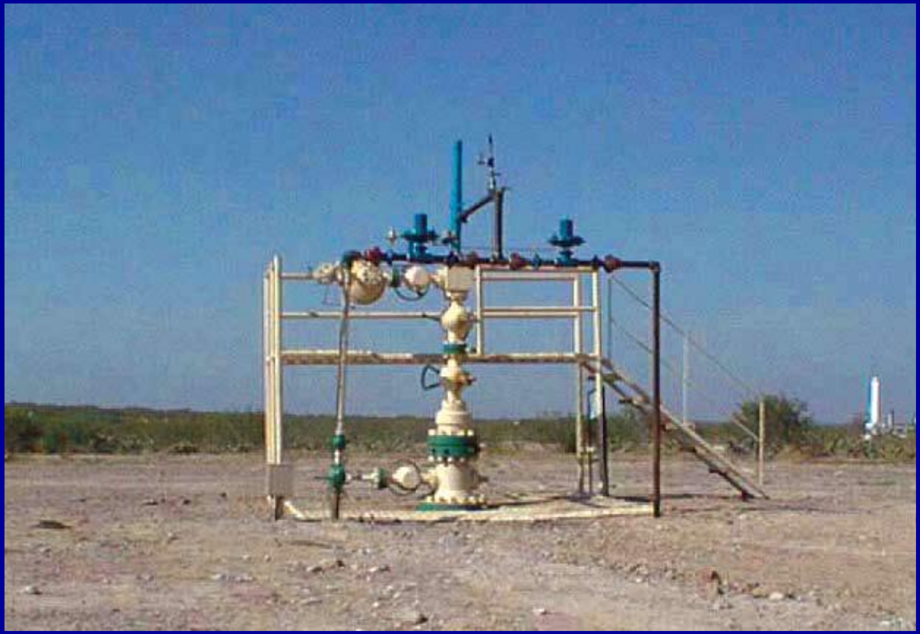
Use IPR curve to set production target

GOAL



1,200
1,000
800
600
400
200
1,600
1,400
1,200
1,000
800
600
400
200
0
DAILY PRODUCTION
DECLINE CURVE
LIQUID LOADING
CASING PRESSURE
200 Mcf / d X 45 days X $ 4 / mcf
= $ 36,000 lost in 45 days !
Use decline curve to set production target
20-Aug
20-Sep
20-Oct
20-Nov
20-Dec
20-Jan
20-Feb
20-Mar
20-Apr
20-May
20-Jun
20-Jul
20-Aug
20-Sep
20-Oct
20-Nov
20-Dec
20-Jan

Optimize a well



Optimize a well

- Know production target (Flow rate or casing pressure)
- Mechanical considerations
  - Minimize restrictions - chokes, motor valve trim, orifice plate, etc
  - No holes in tubing
  - Same ID spring to spring
  - No packer
  - Bottom hole spring location
  - End of tubing relative to perforations
- Select the appropriate plunger

Optimize a well

- Use checklists!
  - Pre-Installation
  - Installation
  - Troubleshooting
  - Etc
- Select the appropriate algorithm
  - Time assumes limited well variations
  - Self adjusting algorithms can be less labor intensive
  - Minimize variation! Same lift pressure and liquid load
  - Optimize production – use plunger velocity as indicator

Optimize a well

Pre-Installation checklist

Item	Description	How determined?	Yes	No
1	Approaching liquid loading	○ Currently adding foaming agent ○ Flow rate is less than critical ○ Production peaks and valleys	✓	
2	Prior 90 day production chart available?		✓	
	Well bore diagram available		✓	
	Well bore survey available		✓	
3	Current choke setting	Evaluate at full open choke	✓	
	Packer in well (2000 scf / bbl / 1000 ft of lift)			✓
	Gas lift mandrel in well			✓
	Sufficient gas volume (400 scf / bbl / 1000 ft of lift)	○ Actual = ________ ○ Required = ________	✓	
	Sufficient gas pressure (Lift pressure >/= 2 X Liquid load)	○ Lift pressure (after X time shut-in) = ____ ○ Liquid load = ____	✓	

Optimize a well

Pre-Installation checklist

Item	Description	How determined?	Yes	No
4	Estimate production increase	Review prior 90 day downtime Review production chart Review IPR curve A pressure reduction of X = Y Mcf = Z $'s	✓	
5	Known plumbing configuration		✓	
6	Reviewed data sheet with supplier		✓	
7	Orifice plate ID known	ID = ___________	✓	
	Motor valve trim size known	Trim size / type = ____________	✓	
	Check for other restrictions		✓	
8	Determine bottom hole spring reqm'ts	Location, seating nipple type / ID, standing valve with pressure relief spring	✓	
9	Determine telemetry plan. Contact IT and gas measurement group if needed		✓	
10	Suppliers contacted, parts available. Installation schedule confirmed.		✓	

Optimize a well

Pre-Installation checklist

Well loaded symptoms

- ❑ Well is down frequently
- ❑ Adding foaming agent to well
- ❑ Intermittent well
- ❑ Frequently swabbing or venting
- ❑ Production fall off decline curve
- ❑ Significant peaks and valleys in production chart
- ❑ Flow rate nearing critical

Plumbing configuration

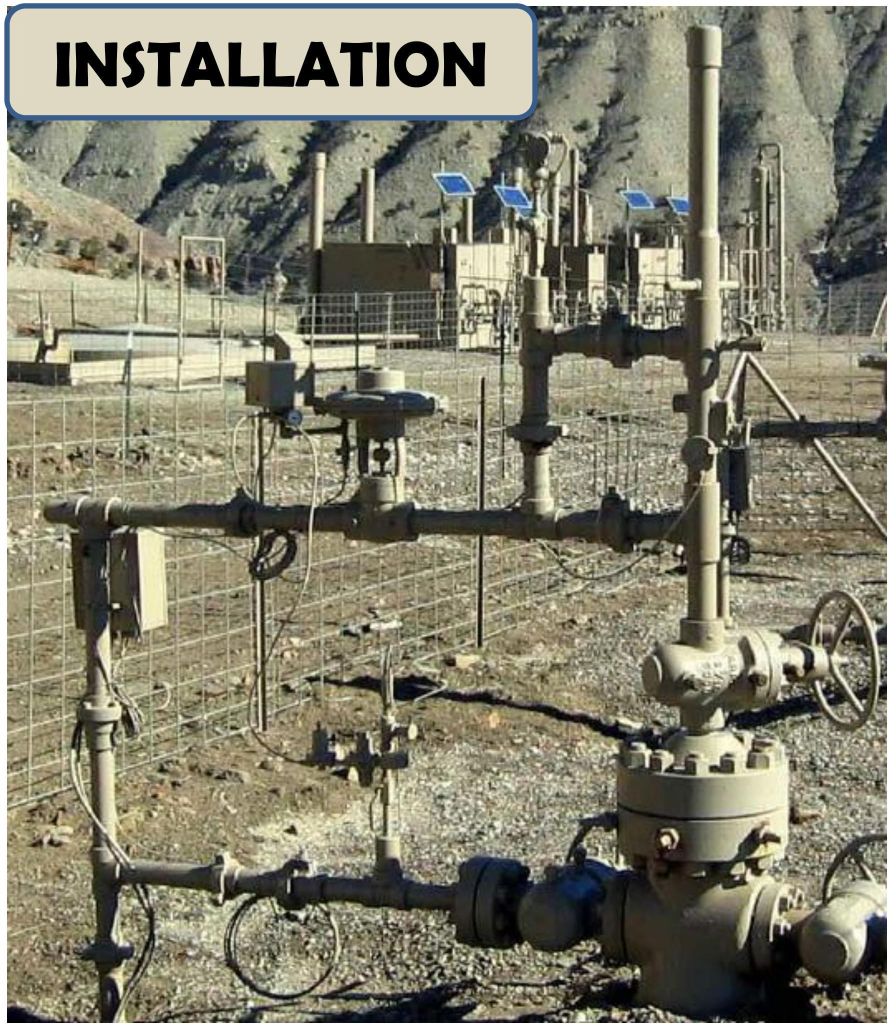
- ❑ Ensure dry, clean gas supply to solenoid
- ❑ By Pass loop for motor valve needed?
- ❑ ID ball valve locations.
- ❑ Sufficient ports for transducers, gauges, etc
- ❑ Ensure no liquid traps
- ❑ Minimize number of 90 degree bends.
- ❑ Platform needed to access lubricator?
- ❑ Emergency shut-down device required?

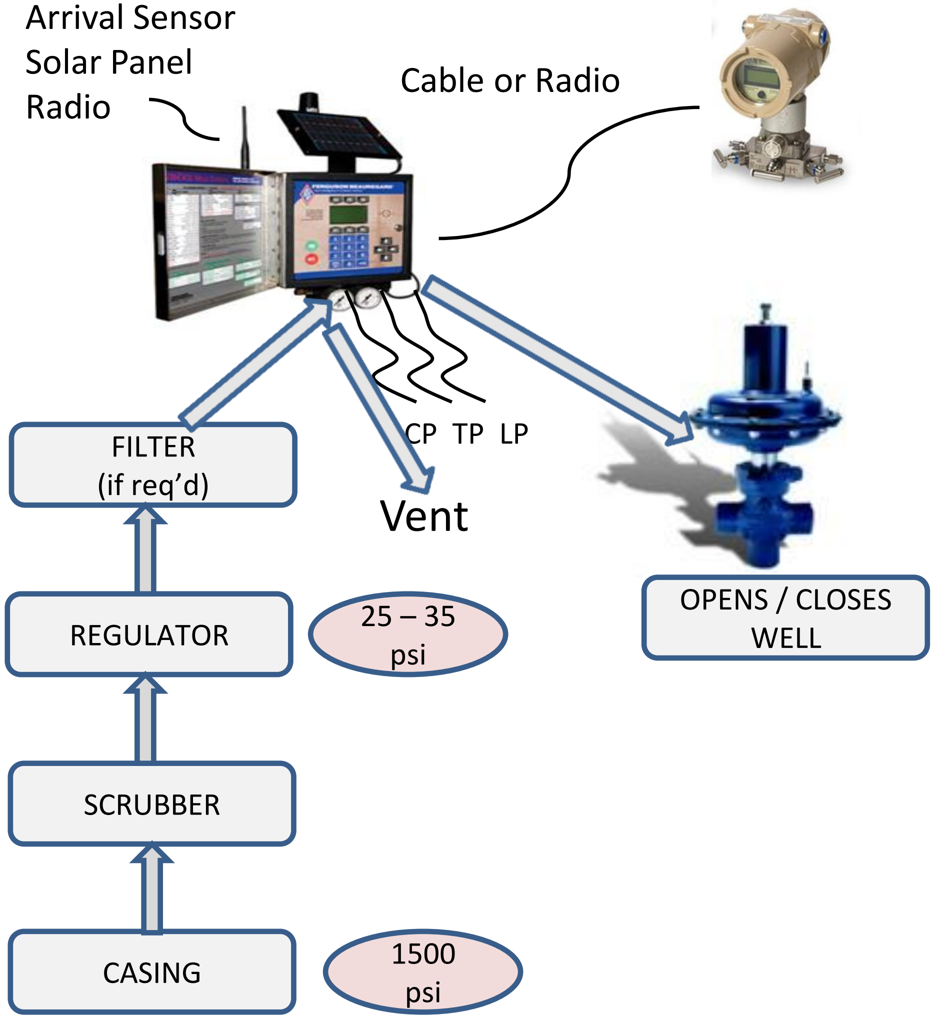
Bottom hole sprig location

- ❑ Know seating nipple ID
- ❑ Horizontal wells - Less than 50 degree deviation.
- ❑ Vertical wells – as low as possible and still surface plunger
- ❑ Prefer standing valve with pressure relief spring

Optimize a well

Installation Process

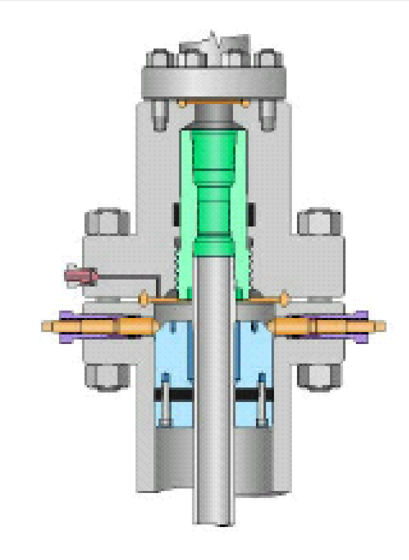


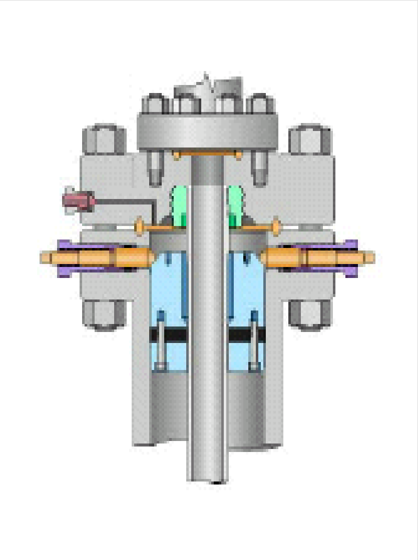


Optimize a well

Installation & Start-up Process

1. Set tubing plug and pressure test tubing. If tubing integrity is good, continue.
2. Check tubing diameter using a ring gauge. If necessary, broach the tubing to ensure no tight spots between the seating nipple and lubricator connection point.
3. Ensure well head diameter is the same as the tubing ID. If larger, sleeve the wellhead.
4. Prepare the flow line and install the flanged control valve for plunger lift control.
5. Install the lubricator (dual outlet preferred) on the wellhead and plumb in the flow line.





Optimize a well

Installation & Start-up Process

6. Set the bottom hole spring assembly at the prescribed location.
7. Install the plunger lift controller, ensuring required supply line pressure to the solenoid latch valve is **reliable and free of debris and liquid**. Do not over pressurize the solenoid valve or motor valve!
8. With the well closed, observe casing and tubing pressure. If the well is liquid loaded, swab the well until the available Lift Pressure (Casing – Line) is at least 2 times the Liquid Load in the tubing (Casing – Tubing).
9. Engage the catcher to hold the plunger. Place the selected plunger in the lubricator. **Ensure the plunger selection matches the well conditions.**
10. Observe the casing pressure. If casing pressure is high, resulting in a potential rapid plunger run, open the well to bleed off some casing pressure until it is in an acceptable range. Be careful not to liquid load the well during this process.
11. If casing pressure is in an adequate range, drop the selected plunger.

Optimize a well

Installation & Start-up Process

11. Using plunger fall time calculations, allow adequate time for the plunger to reach the bottom hole spring assembly.
12. Document the lift pressure prior to opening the well. Allow the plunger to surface, documenting plunger arrival velocity. Generally, plunger arrival velocities between 500 and 1000 feet per minute are desirable.
13. Allow the well to flow until the flow rate approaches the critical flow rate. Then, shut the well in, documenting the liquid load soon after the well is closed. Compare the liquid load, lift pressure and plunger arrival velocity.
14. If necessary, adjust controller settings in preparation for the next cycle to achieve optimal production at desirable plunger velocities.

- Optimal Production is achieved at the lowest flowing bottom hole pressure
- Practical application strives toward operating at low casing pressures, thus lifting small amounts of fluid on each cycle, cycling many times a day.

Optimize a well

Algorithm

Open Conditions

(After fall time elapses)

- Time = set point
- Tubing pressure = set point
- Casing pressure = set point
- Tubing/Casing = set point
- Tubing – Line = set point
- Lift pressure = set point
- Lift pressure = Foss and Gaul
- Load Factor = Set point

Load Factor = Liquid Load / Lift Pressure

Close Conditions

(After plunger surfaces)

- Time = set point
- Tubing pressure = set point
- Casing pressure = set point
- Flow Rate = set point
  = Critical flow
  = % of critical

Objective:
Open at minimum pressure required to surface plunger at desired plunger velocity

Objective:
Maximize production while allowing the designed quantity of liquid to enter tubing on every cycle

CONVENTIONAL PLUNGER EXAMPLE (8000 foot deep well)

TRADITIONAL

- Fall time (Use EchoMeter to optimize)
  - Gas – 7750 ft @ 180 fpm
  - Liquid – 250 ft @ 40 fpm (1 bbl)
  - Total = 43 min + 6 min
  - Total = 49 min + 10%
  - Total = 54 min
- CP Build
  - 30 min to reach req'd pressure
  - Higher pressure req'd to lift 1 bbl
- Rise Time
  - 600 fpm = 13 min
- Production mode (afterflow)
  - 60 min
- Total cycle = 2.6 hours or 9 trips / day
- **Total Production time = 9 hours (Partially in liquid loaded tubing)**

FREQUENT TRIPS

- Fall time (Use EchoMeter to optimize)
  - Gas – 7937 ft @ 800 fpm
  - Liquid – 63 ft @ 40 fpm (¼ bbl)
  - Total = 10 min + 1.5 min
  - Total = 11.5 min + 10%
  - Total = 12.5 min
- CP Build
  - Open when plunger reaches bottom
  - Less pressure req'd to lift ¼ bbl
- Rise Time
  - 600 fpm = 13 min
- Production mode (afterflow)
  - 15 min
- Total cycle = 40.5 min or 35.5 trips / day
- **Total Production time = 8.75 hours (Clear tubing, lower flowing pressure)**

Optimize a well

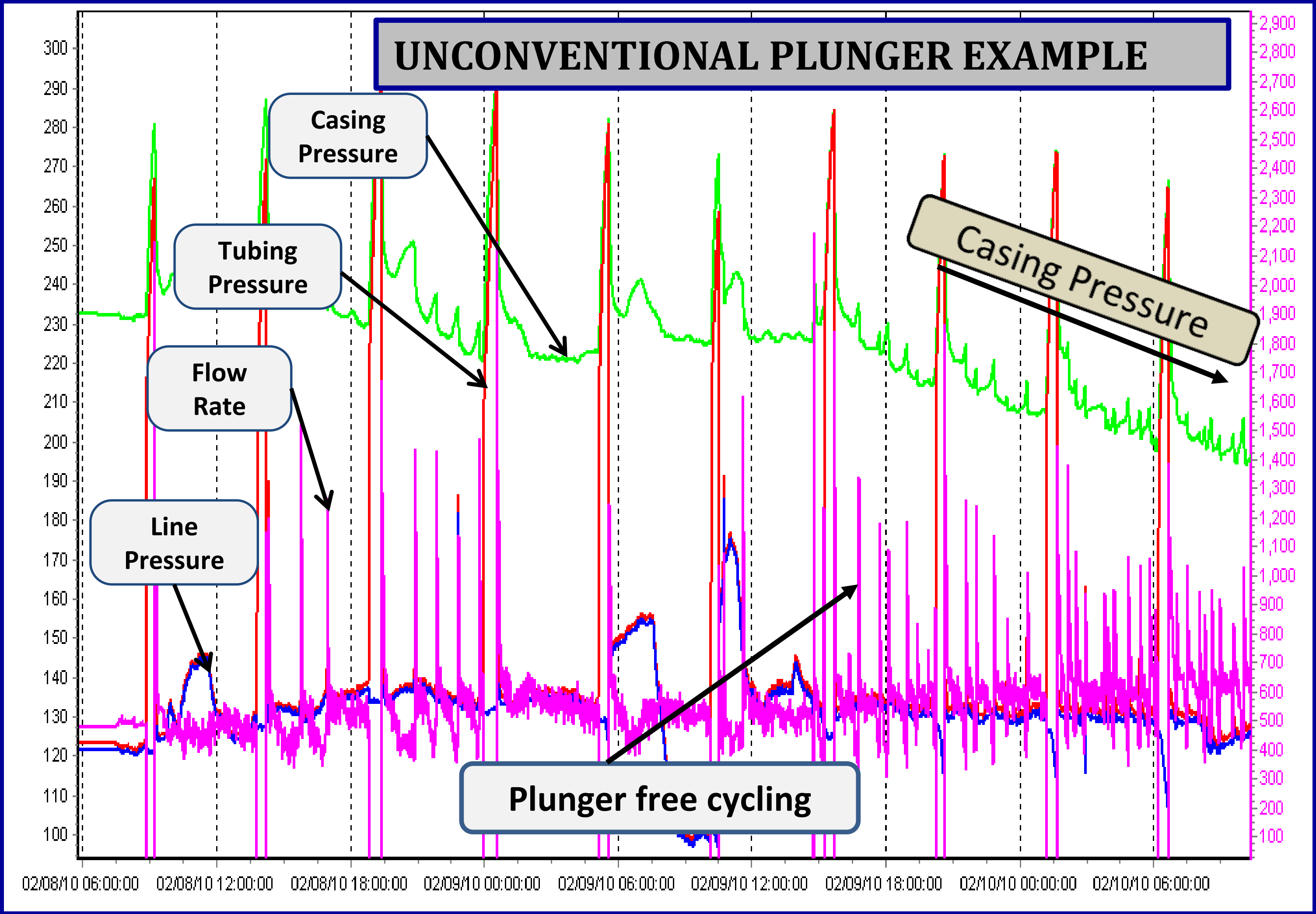
Design Lift Cycle

Plunger falls when well is open

Only round trip times recorded

Less shut-in

Excessive plunger velocities possible



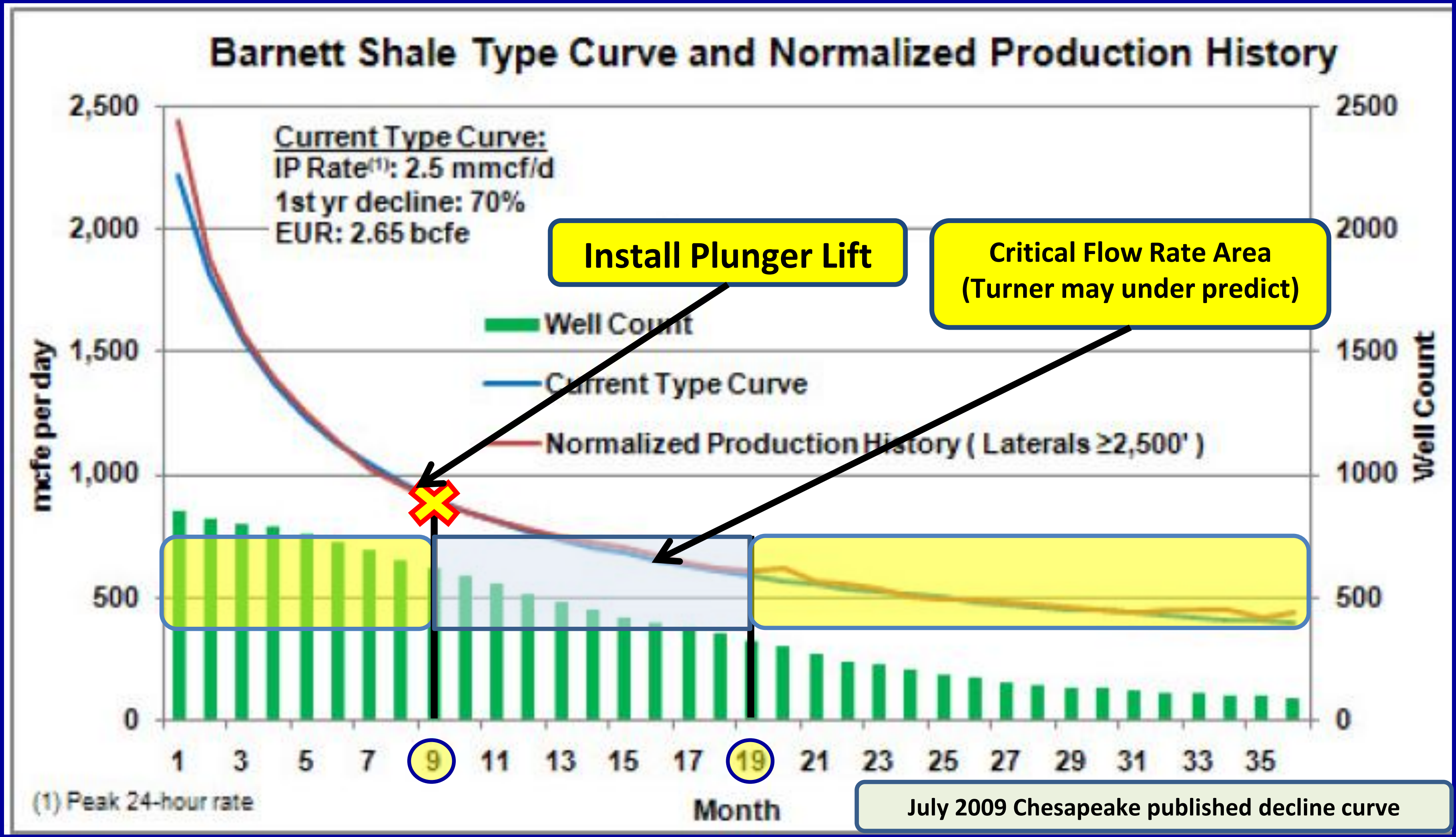
Optimize many wells

Optimize many wells

1. Install artificial lift before production declines
2. Determine best artificial lift type for well conditions
3. Know target (production or casing pressure)
4. Aggressively prevent unplanned downtime
5. Troubleshoot – detect rapidly, solve root cause!
6. Prioritize wells daily – before driving route
7. *Produce at the lowest flowing bottom hole pressure*
8. Train wide and deep!

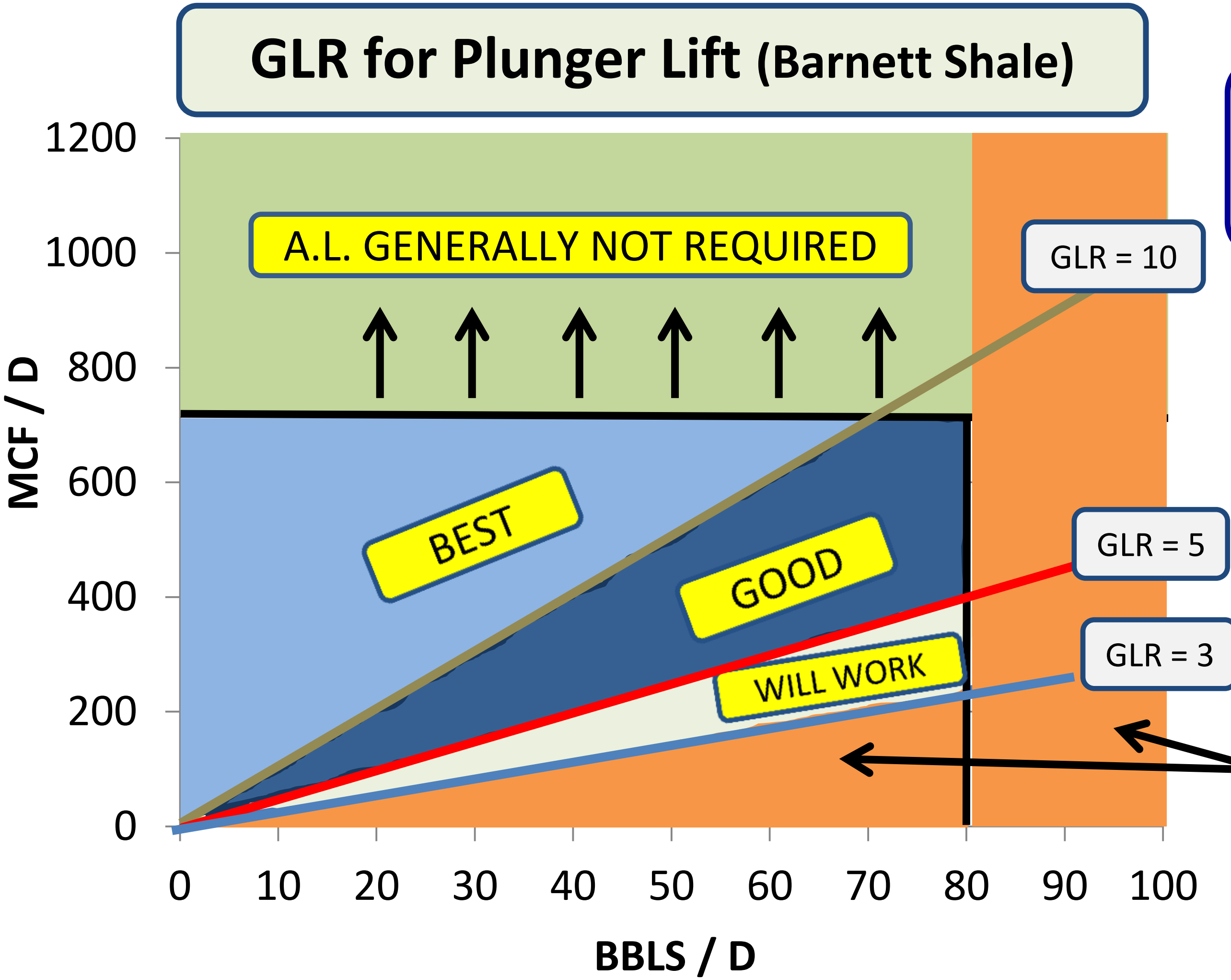
Optimize many wells

1. Install A.L. before liquid loading



Optimize many wells

2. Know which A.L. type to use



Minimum Gas Volume Required
(7500 ft TVD)

- 400 scf / Bbl / 1000 ft of Lift
- 3 Mcf per BBL or GLR = 3

Note:
Higher GLR wells are easier to keep running, resulting in less non productive time

CONSIDER:
2 Stage Plunger Lift,
Gas Assisted Plunger Lift,
Plunger Assisted Gas Lift

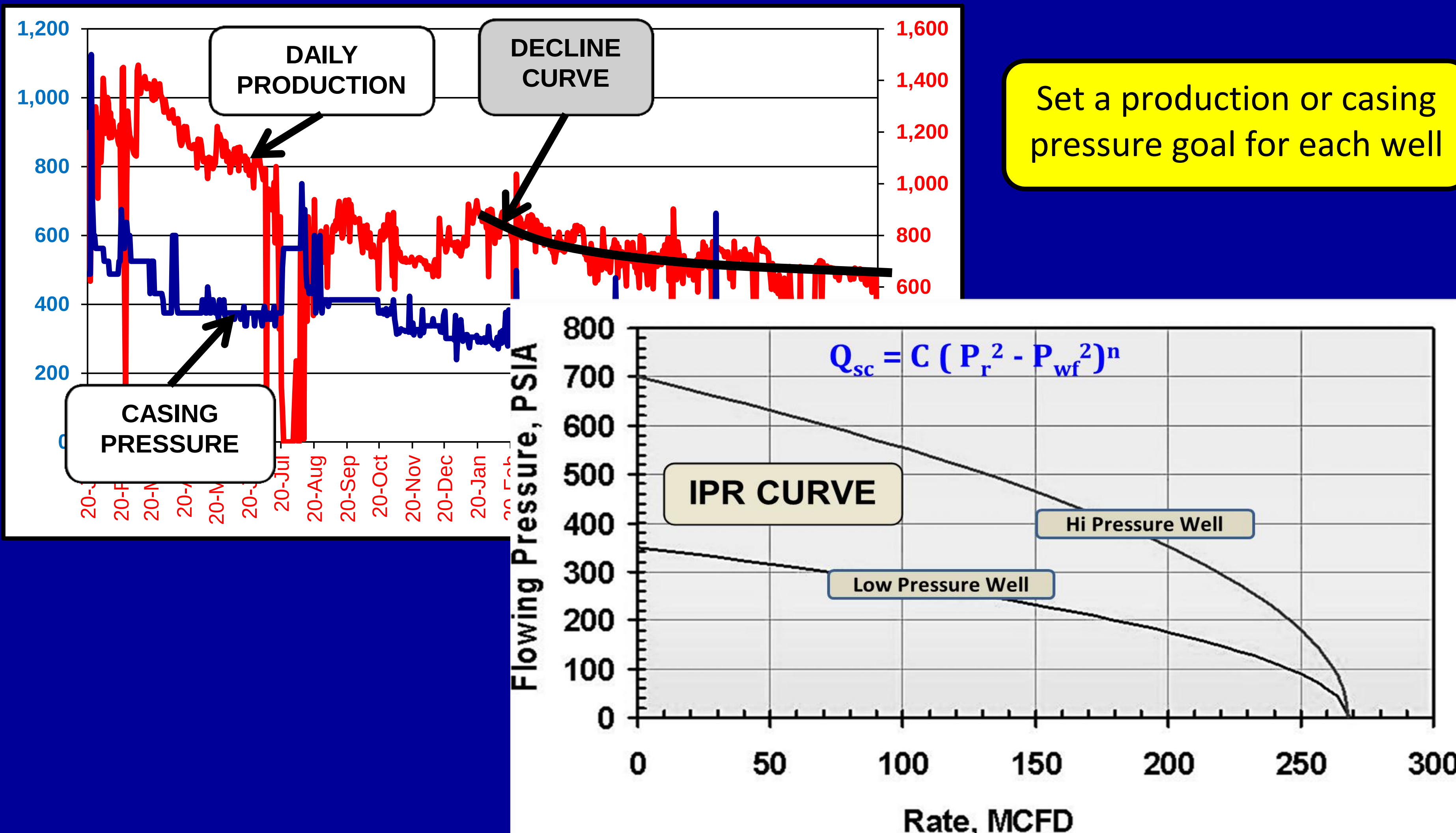
Optimize many wells

2. Know which A.L. type to use

TWO STAGE PLUNGER LIFT	GAS ASSISTED PLUNGER LIFT	PLUNGER ASSISTED GAS LIFT
○ Low GLR, marginal wells	○ Low GLR wells	○ Low GLR wells
○ 200 scf / bbl / 1000 ft	○ Gas injected to annulus 400 scf / bbl / 1000 ft	○ Add plunger to intermittent gas lift wells
○ Two or more plungers in the same well	○ Short shut-in times	○ Reduces injected gas requirements (30 % range)
○ Ideal for slim hole or wells with packers	○ + / - 250 Bbls / day possible	○ Eliminates fall back
○ Can be used with injection gas	○ Plunger seal is important	○ Increases production

Optimize many wells

3. Set production target – flow rate or casing pressure



Set a production or casing pressure goal for each well

Optimize many wells

4. Aggressively prevent unplanned downtime

PRODUCTION ($ 4.50 / Mcf)	$'s per day	$'s per week	$'s per month
25 Mcf / day	$ 113	$ 788	$ 3,150
50 Mcf / day	$ 225	$ 1,575	$ 6,300
100 Mcf / day	$ 450	$ 3,150	$ 12,600
250 Mcf / day	$ 1,125	$ 7,875	$ 31,500
500 Mcf / day	$ 2,250	$ 15,750	$ 63,000
750 Mcf / day	$ 3,375	$ 23,625	$ 94,500
1,000 Mcf / day	$ 4,500	$ 31,500	$ 126,000

How long to re-start a well? How long to detect after problem occurs, allocate well tender time, get parts, schedule wire line, schedule swab rig, etc ?

Optimize many wells

4. Aggressively prevent unplanned downtime

PREVENTATIVE MAINTENANCE

Inspection Point	Criteria	Technique	Daily	Weekly	Monthly	Other
Motor Valve	Fully opens and closes	Visually observe	✓			
	Supply line at 25 - 35 psi	Check supply line regulator	✓			
	Vent line clear	Motor valve closes	✓			
	Leaks	Review pressure chart		✓		Or upon reduced production
	Replace trim	Replace prior to failure				Set replacement schedule
Lubricator	Leaks	Visual Inspection	✓			
		Check O-ring			✓	
		Grease threads			✓	
	Micro fractures, damaged threads	Visually inspect after all fast arrivals. Consider flanged lubricator.				Inspect after all fast arrivals. Consider annual NDT.
	No sand / ice in top section	Visually inspect			✓	More frequently if needed
Lubricator Spring	Compression set	Measure edge of lubricator to spring			✓	Replace at appr. ½" reduction
	Fractured	Observe loose pieces	✓			
Catcher	Operational	Catch plunger			✓	
	Lubricator ID clear	ID clear with catcher disengaged			✓	
Arrival Sensor	Senses surfaced plunger	Observe plunger arrival(s)	✓			
	Wire to controller	Secure and does not obstruct valves	✓			
Bottom Hole Spring	Intake clogged	Check TP build time	✓			Watch charts (pressure, flow)
	Compression set spring	Pull and inspect spring				6 month intervals until proven otherwise
	Fishing neck integrity	Fishing neck not bent or mushroomed				
	Seating cups	Replace when spring is pulled				
	Fractured spring	Damaged plungers				

Optimize many wells

4. Aggressively prevent unplanned downtime

PREVENTATIVE MAINTENANCE

Inspection Point	Criteria	Technique	Daily	Weekly	Monthly	Other
Plungers	Fractured	Observe plunger cycle performance	✓			Check if missing arrivals
	Correct for well conditions	Well conditions stable?			✓	
		Production target achieved?			✓	
	Functional moving parts	Moving parts free, but not loose		✓		
	Loose parts	No obvious loose parts		✓		
	Fishing neck integrity	Fishing neck not bent or mushroomed			✓	
	Worn	Measure plunger OD			✓	Replace per schedule
Downstream Valves	Leaks	Review Pressure Chart		✓		Or upon reduced production
Battery	Voltage less than 10.5 V (12 V system)	Review Voltage	✓			
Tubing	Loss of integrity	Review pressure charts		✓		Or upon reduced production
Master valves and wing valves	Leaks	Ensure no leaks when fully closed		✓		
	Grease	Grease valves. Excessive grease may foul plunger and hang it in tubing			✓	Schedule per manufacturer recommendations

NOTE: Above is an example of a Preventative Maintenance program for plunger lift equipment. Based on actual field and specific well site experience, adjustments are anticipated.

Optimize many wells

5. Troubleshoot -

1. **DETECT RAPIDLY**

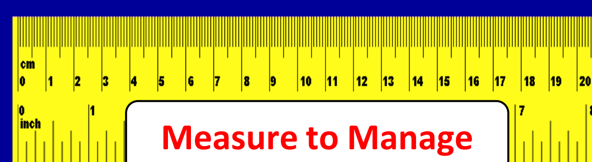
   Station Name : Well # 2 H
   Alarm Text : Low Sales Press
   Time Logged : Feb 4, 2011, 7:06 AM
   Value : 32.9
   Set point : 45.0
   ALARM!

2. **DIAGNOSE WITH DATA**
   - Then prescribe

3. **WORK THE RIGHT PROBLEM**
   - Pareto Analysis
   - Training? Process ?

4. **SOLVE ROOT CAUSE**
   - Plan, Do, Check, Act
   - 5 Why's
   - A3's

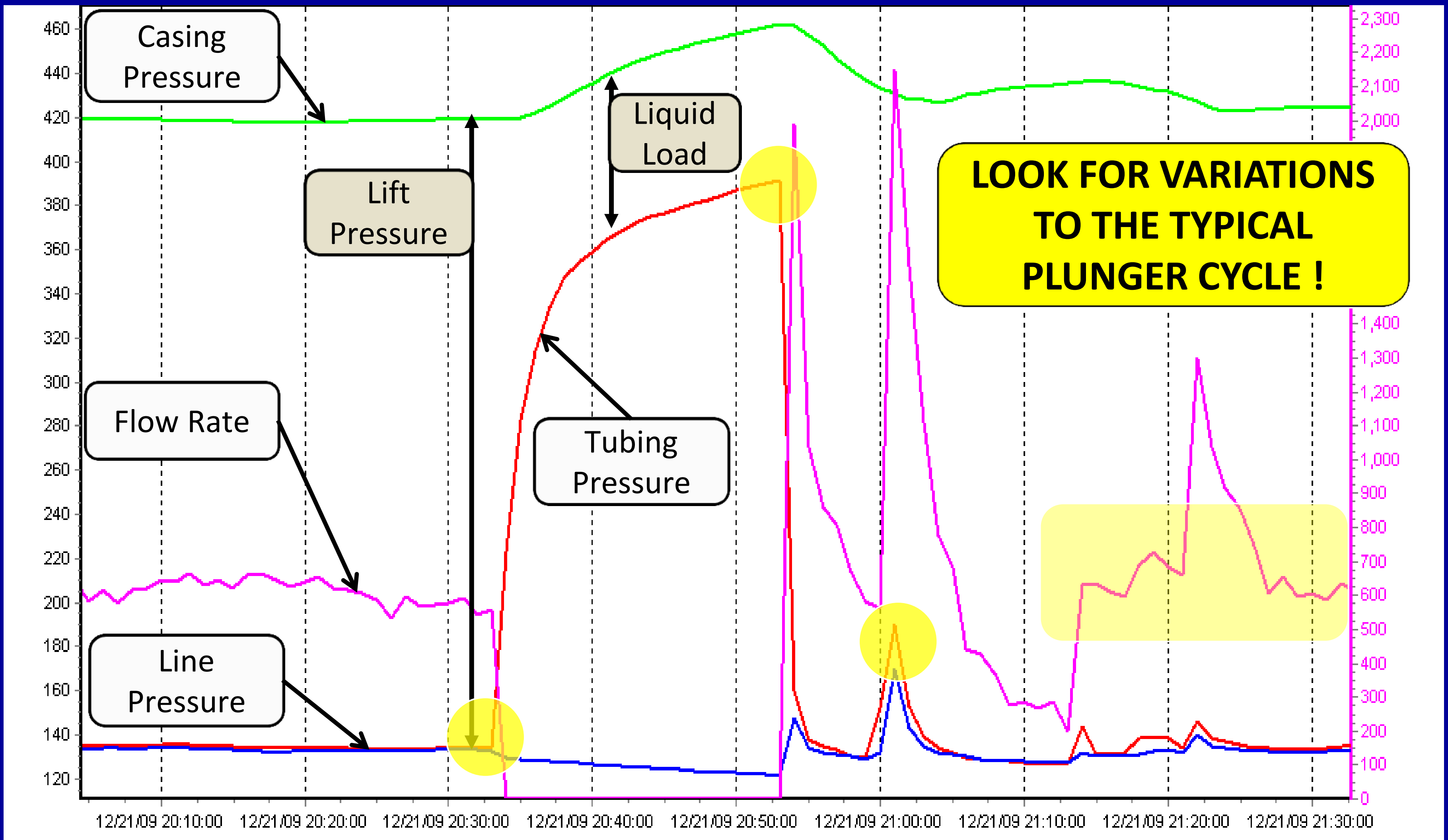
USE TELEMETRY !



Measure to Manage

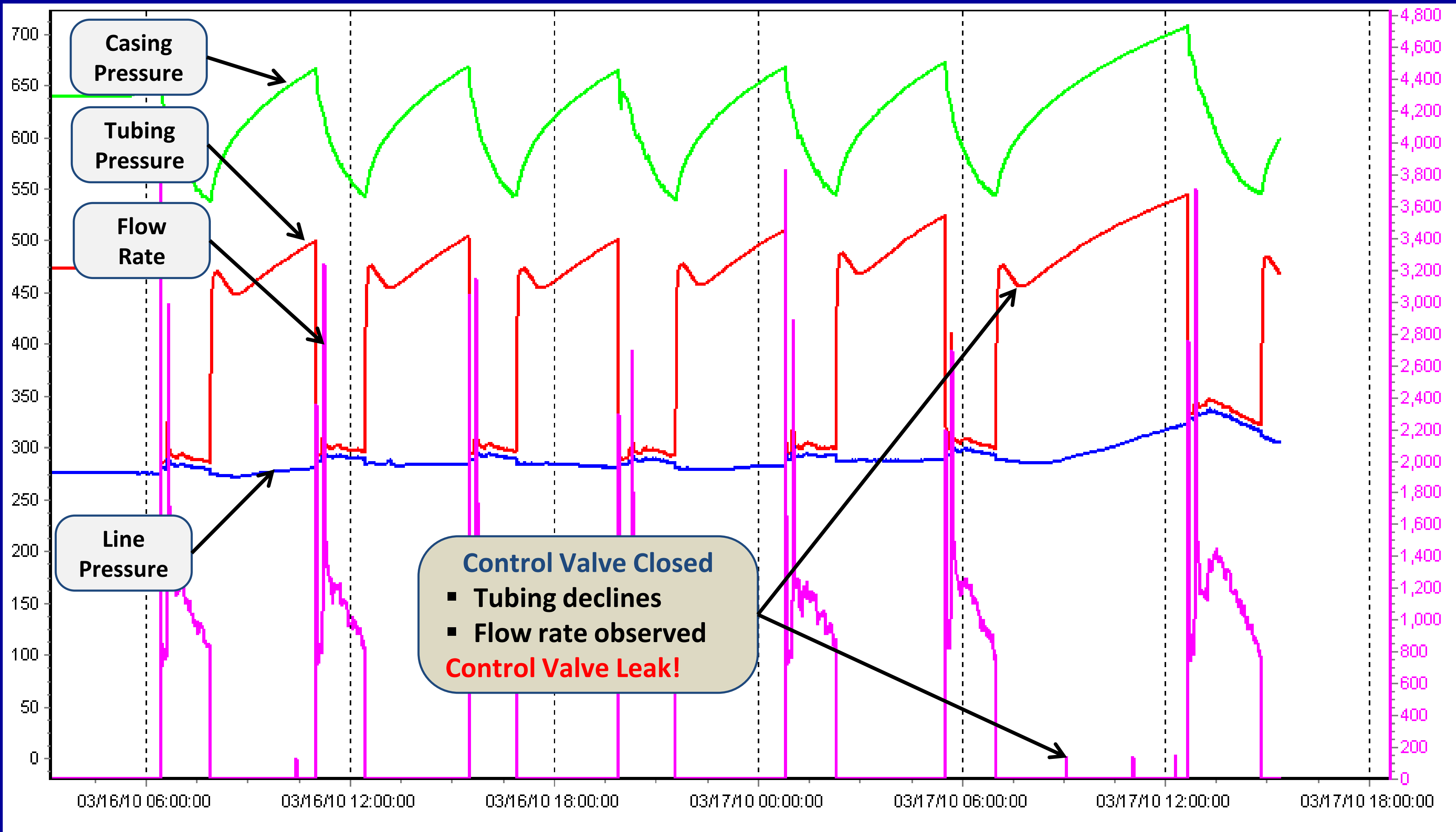
Optimize many wells

5. Troubleshoot -



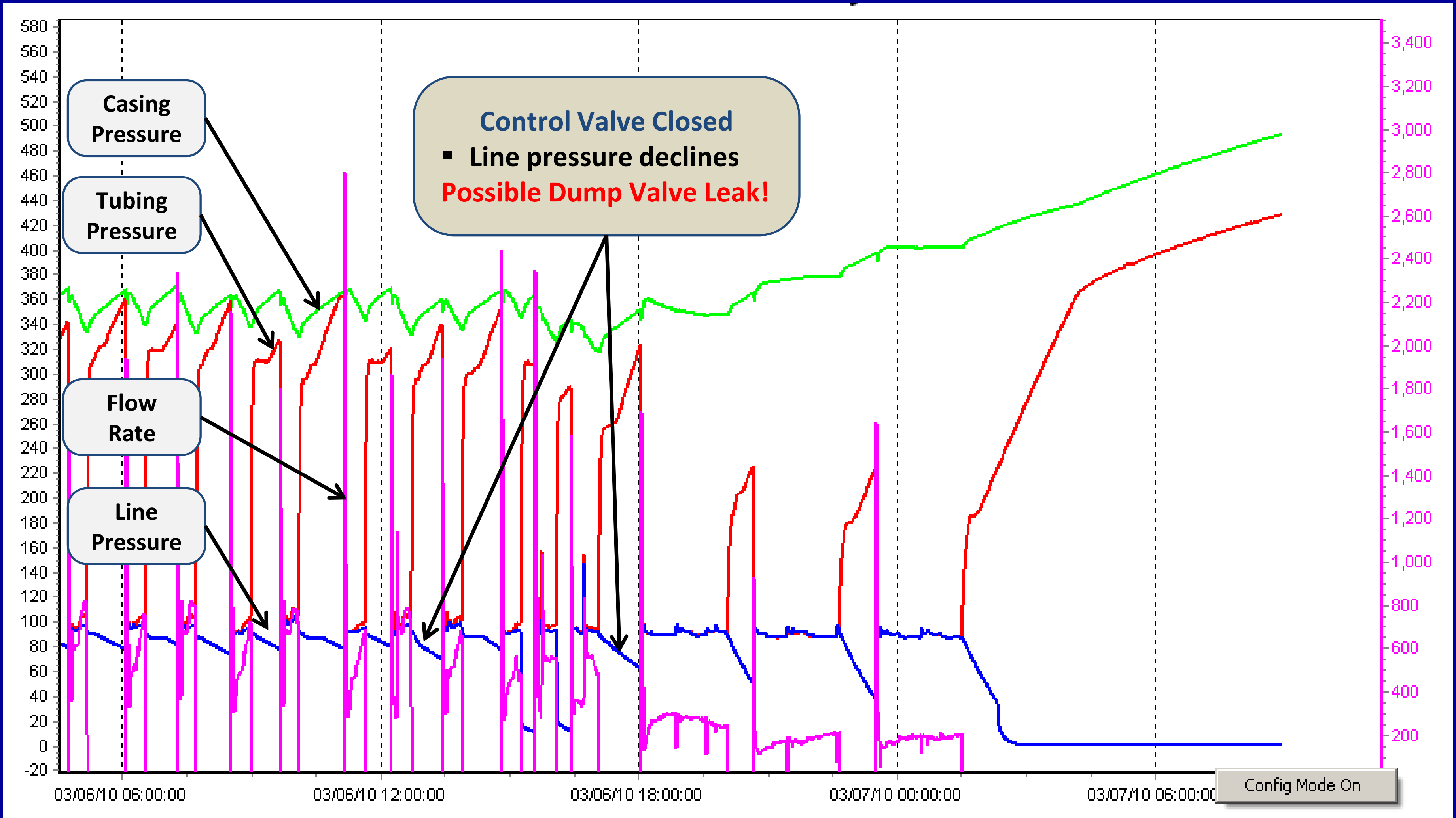
Optimize many wells

5. Troubleshoot -



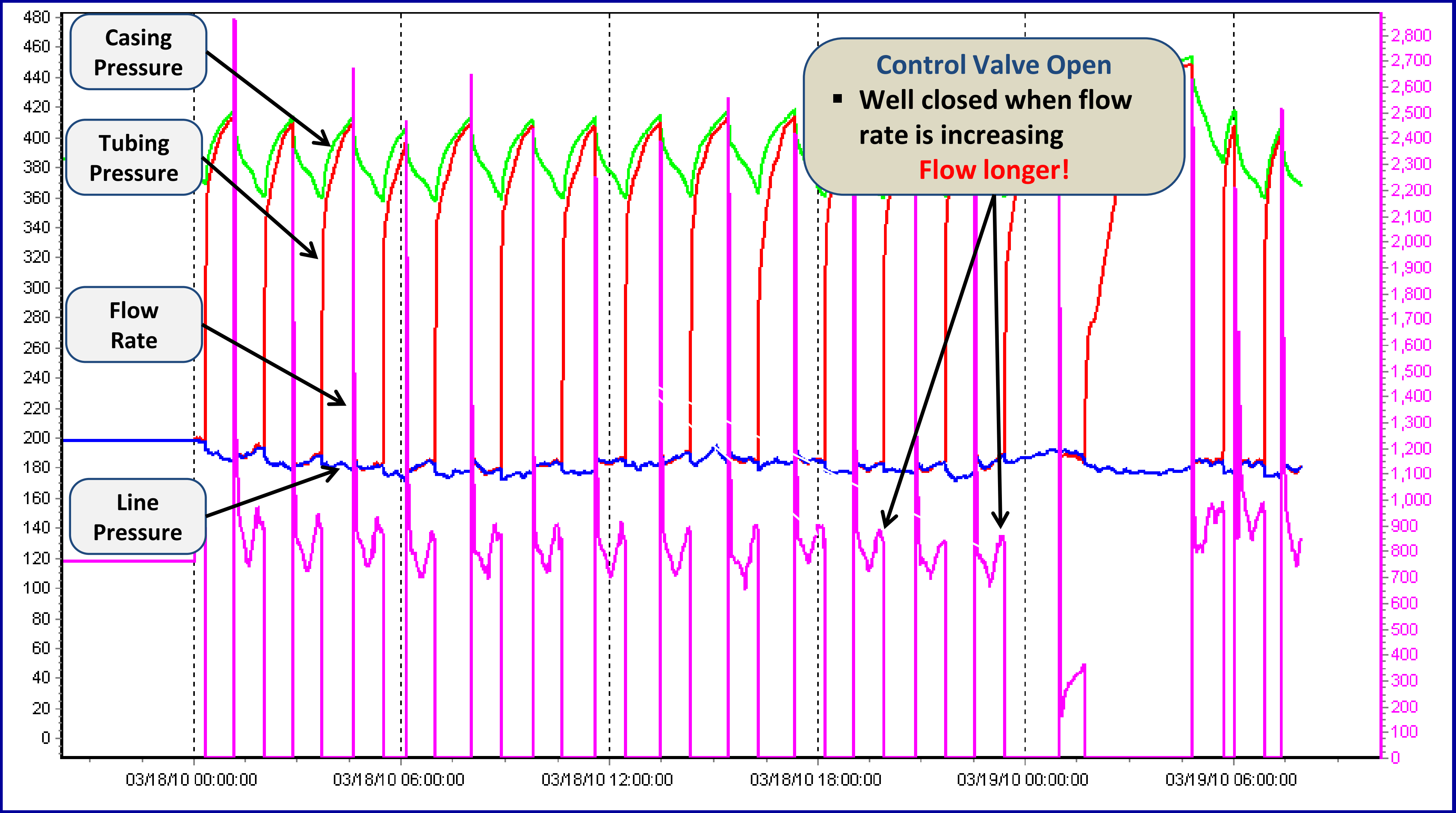
Optimize many wells

5. Troubleshoot -



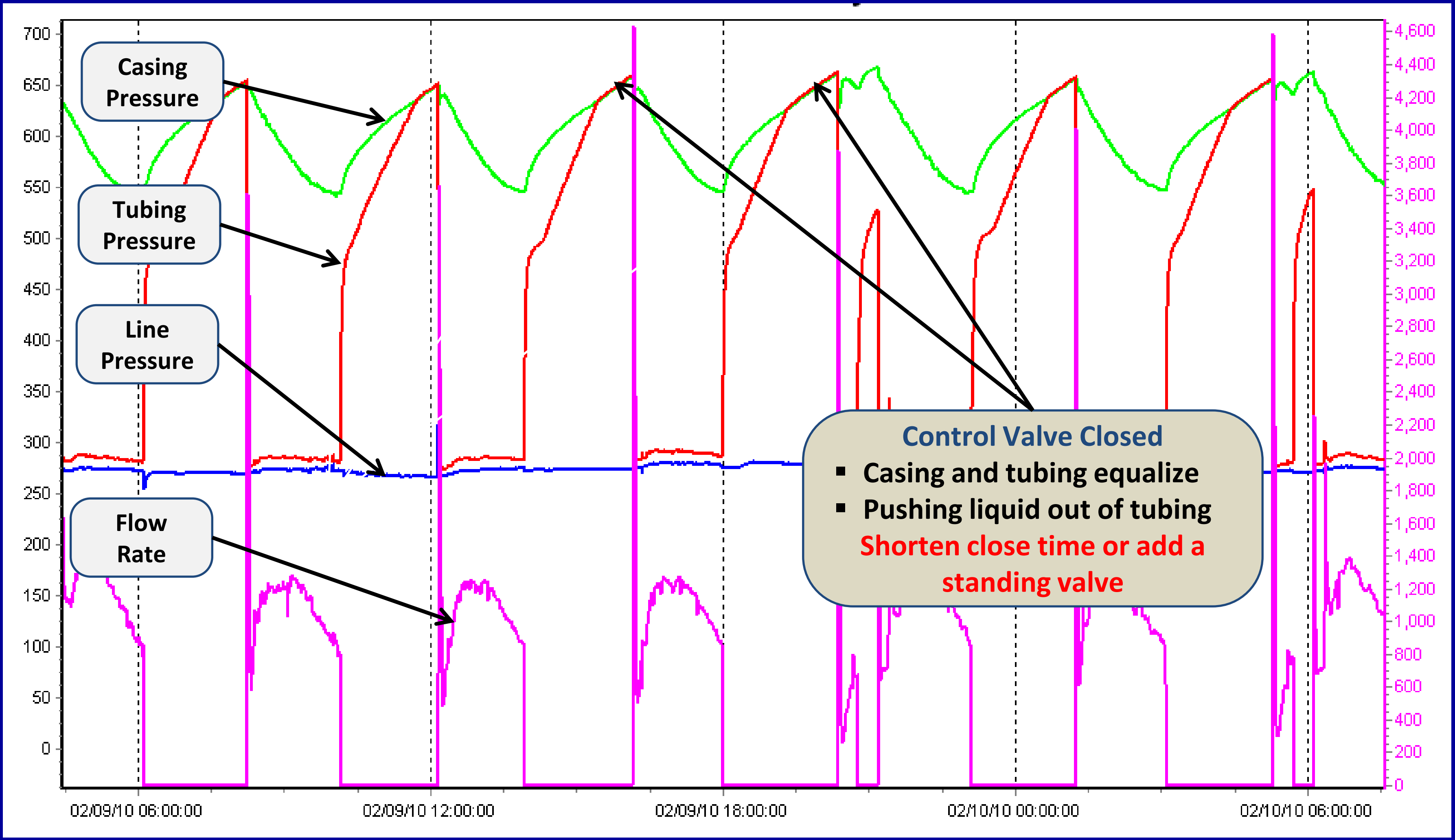
Optimize many wells

5. Troubleshoot -



Optimize many wells

5. Troubleshoot -



Optimize many wells

5. Troubleshoot -

Run #	AT CLOSE Time	Pressures (psi) CP	TP	SLP	CP-TP	Fluid in Tbg	AT OPEN Time	Pressures (psi) CP	TP	SLP	Act. Lift	Req'd Lift	RUN DATA Plunger Rise Time (min)	Velocity (ft/min)	Arrivals Good	Miss	Open Duration	Close Duration	PRODUCTION DATA Gas (Mscf)	Liquid (Bbls)
5341	02/01/11 05:59AM	438	392	151	45	0.41	02/01/11 07:54AM	510	427	150	360	183	7.28	1050	1		00:10	01:54	10.2	0.0
5342	02/01/11 08:05AM	439	386	146	53	0.47	02/01/11 09:50AM	508	417	147	360	197	7.65	1000	1		00:11	01:44	11.7	0.0
5343	02/01/11 10:01AM	436	381	145	55	0.49	02/01/11 11:46AM	505	416	145	360	201	7.68	995	1		00:11	01:45	10.6	0.0
5344	02/01/11 11:57AM	434	381	146	53	0.47	02/01/11 01:42PM	504	413	144	360	197	7.58	1009	1		00:11	01:44	10.5	0.0
5345						0.44	02/01/11 03:34PM	501	416	141	360	187	7.40	1034	1		00:10	01:41	11.0	0.0
5346						0.44	02/01/11 05:24PM	499	411	139	360	186	7.42	1031	1		00:10	01:39	10.7	0.0
5347						0.47	02/01/11 07:12PM	497	409	137	360	193	7.67	998	1		00:11	01:36	10.6	0.0
5348						0.45	02/01/11 08:59PM	494	409	134	360	185	7.38	1036	1		00:10	01:34	10.7	0.0
5349						0.45	02/01/11 10:54PM	495	408										10.4	0.0
5350						0.44	02/02/11 12:58AM	498	414										10.0	0.0
5351	02/02/11 01:09AM	428	375	140	53	0.47														
5352	02/02/11 02:59AM	424	373	138	51	0.46														
5353	02/02/11 05:06AM	427	378	139	49	0.44														
5354	02/02/11 10:56AM	477	416	181	60	0.54														
5355	02/02/11 12:16PM	454	410	158	44	0.39														
5356	02/02/11 01:10PM	433	398	144	35	0.32	02/02/11 02:30PM	498	425	138	361	155	6.35	1204	1		00:09	01:20	10.5	0.0

Liquid Load
Lift Pressure
Plunger Velocity
Close time
Production

Self Adjusting Controllers

Fast Window	Greater than 1000 fpm	Fast Window	• Increase Afterflow Time • Decrease Off Time
Good Window	500 to 1000 fpm	Good Window	• No changes are Performed
Slow Window	Less than 500 fpm	Slow Window	• Decrease Afterflow Time[1] • Increase Off Time

Optimize many wells

5. Troubleshoot -

COMMON PROBLEMS

SYMPTOM	POSSIBLE CAUSES
No arrivals	Plunger stuck in lubricator. Worn plunger. Lift pressure insufficient. Too much liquid. Disconnected arrival sensor. Arrival sensor malfunction. Excessive grease in tubing from wellhead valves. Plunger stuck in tubing – try retrieval plunger. Rapid fall plunger flow valve hung open.
Slow arrivals	Worn plunger. Lift pressure insufficient. Too much liquid. Tubing restriction (scale, paraffin). Wrong plunger style.
Fast arrivals	Fall time too short. Plunger hung in well head – check catcher and well head valves. Tight spot in tubing. Too much lift pressure. Not enough liquid load.
Motor valve will not open	No gas supply pressure – check regulator. Clogged filter. Liquid in gas supply line. Debris in solenoid valve. Solenoid valve malfunction. Hole in motor valve diaphragm.
Motor valve will not close	Liquid in gas supply line. Debris in solenoid valve. Solenoid valve malfunction. Solenoid vent line plugged.
Motor valve leaks	Hydrate or other obstacle in trim. Inspect / replace trim. Consider ceramic trim.
Lubricator top seeps / leaks	Dry threads. Inspect “o” ring. Grease “o” ring.

Optimize many wells

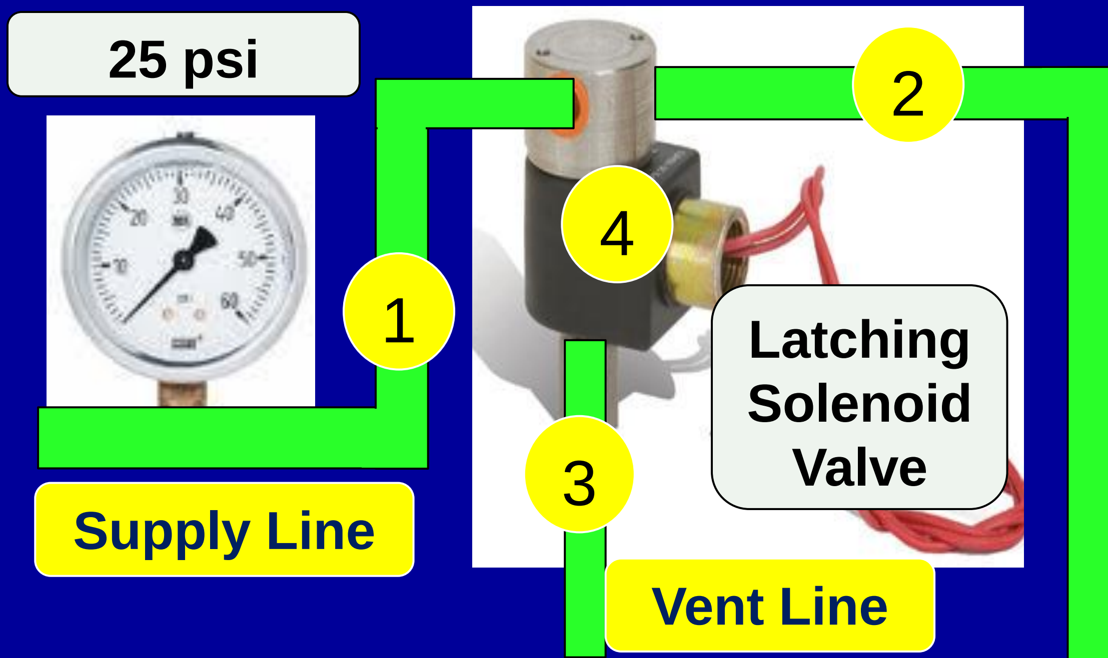
5. Troubleshoot -

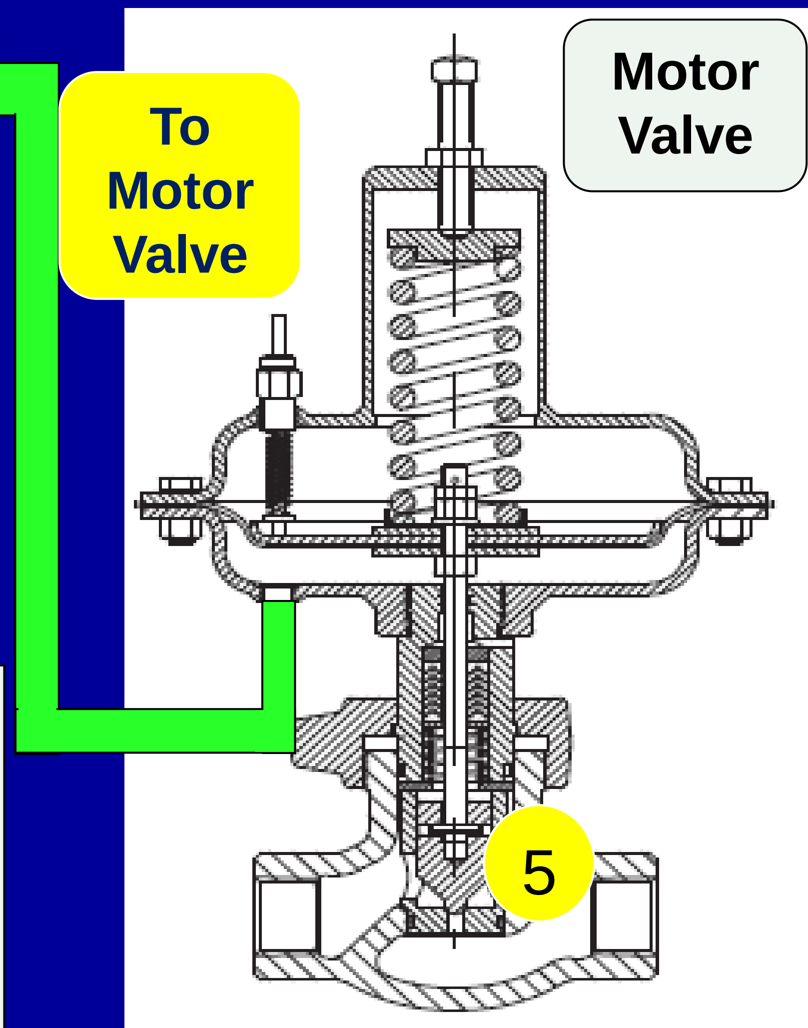
COMMON PROBLEMS

SYMPTOM	POSSIBLE CAUSES
Short battery life	Inspect battery. Inspect solar panel wires. Inspect solar panel – clean? 45 degree? Facing south? Check radio – constant on?
Plunger fishing neck mushroomed	Lubricator spring worn or too stiff. Fast plunger runs.
Catcher will not trap plunger	Inspect / replace spring (ball and spring type).
Motor valve closed, flow rate not zero	Motor valve leak or calibrate flow meter
Flow rate increasing at end of afterflow	Flow longer
Motor valve closed, TP & CP slowly equalize, fast and dry plunger runs, possible liquid produced after plunger arrives	Pressure is pushing liquid out of tubing. Shorten close time or add a standing valve.
Fall time elapsed, casing pressure not increasing, shut-in time remains	Reduce shut-in time or open at lower lift pressure
Consistent plunger runs; consistent fluid loads followed by instant liquid loading and no plunger runs	Tubing set too high. Liquid column slowly builds below tubing. When column reaches tubing, well loads
Fast, dry plunger runs. Liquid in tubing on each cycle	Fall time too short

Optimize many wells

5. Troubleshoot -



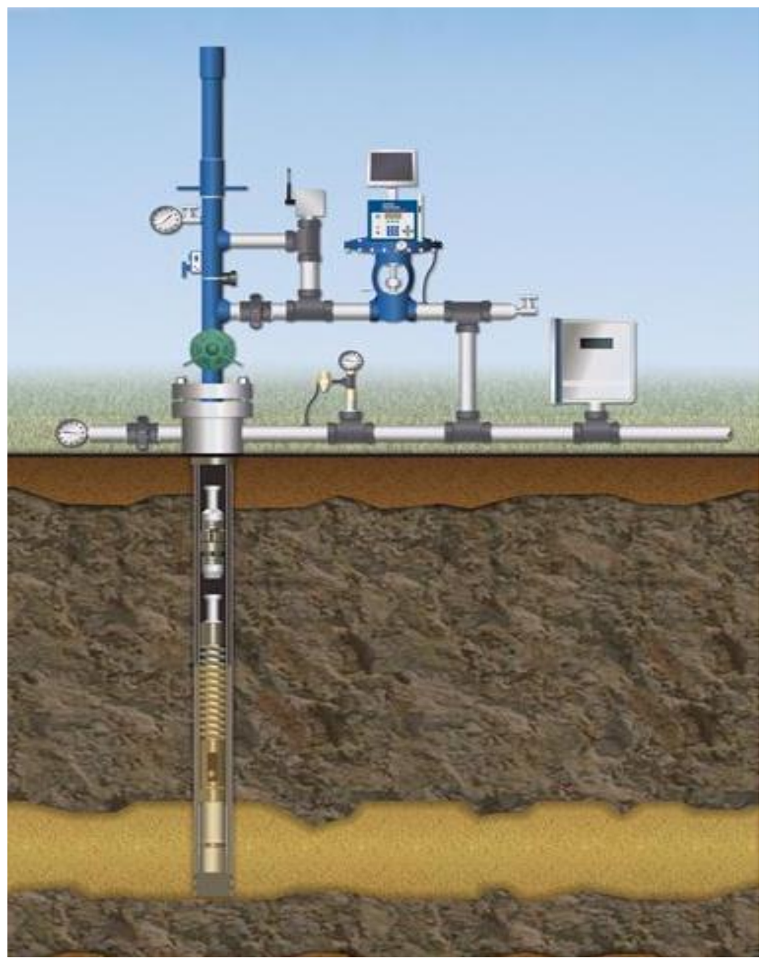


1) Check supply line pressure (clean gas)
2) Check pressure to motor valve
3) Ensure vent line is not obstructed
4) Ensure solenoid valve is functioning
   - Clean if obstructed
5) Check trim/seat for wear, leaks

Optimize many wells

5. Troubleshoot -

COMMON PROBLEMS

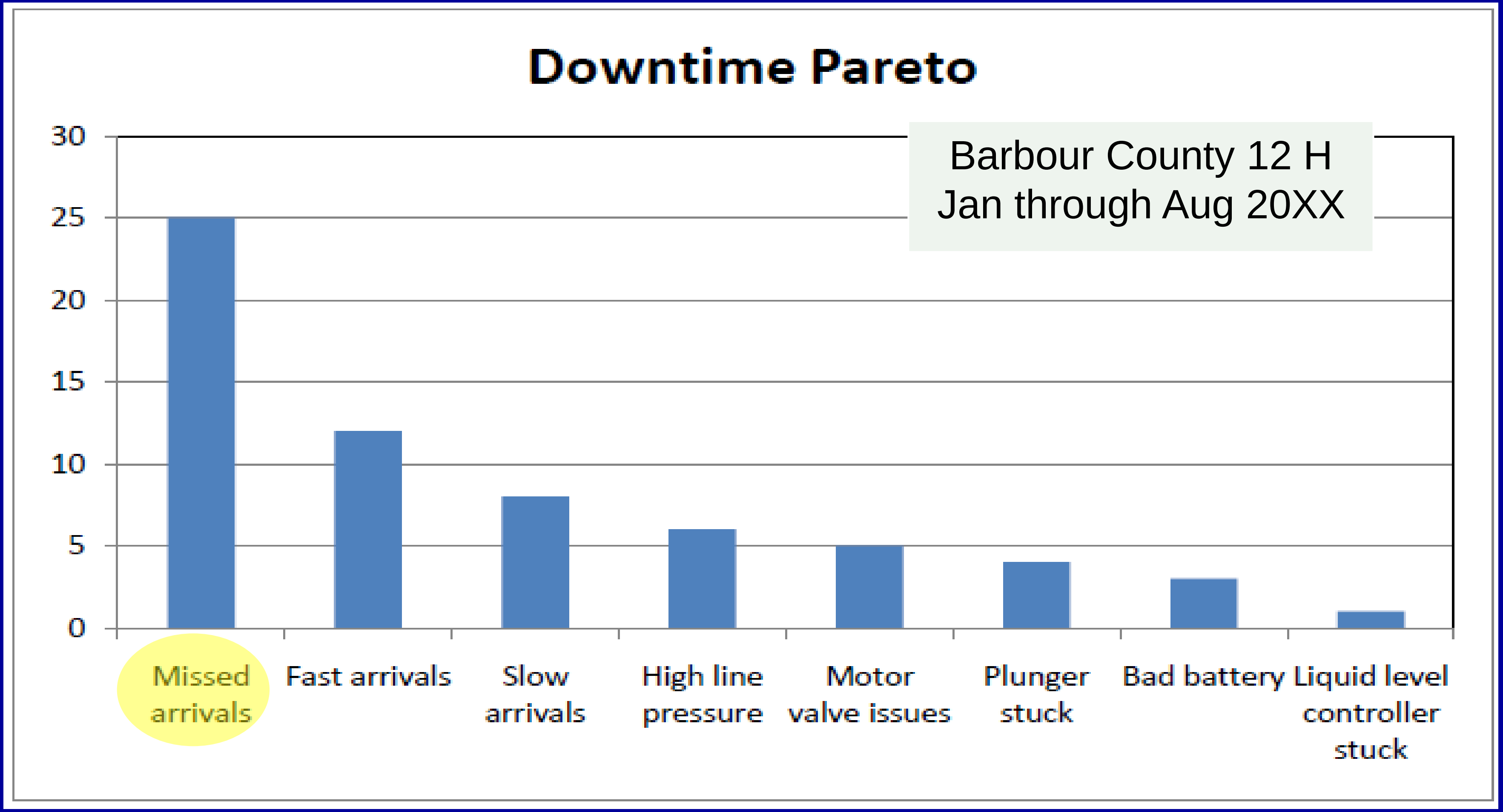


- **If vent to tanks to raise plunger, how long should you vent after plunger surfaces?**
- **If swab, how do you know when it's OK to restart the plunger?**

Optimize many wells

5. Troubleshoot -

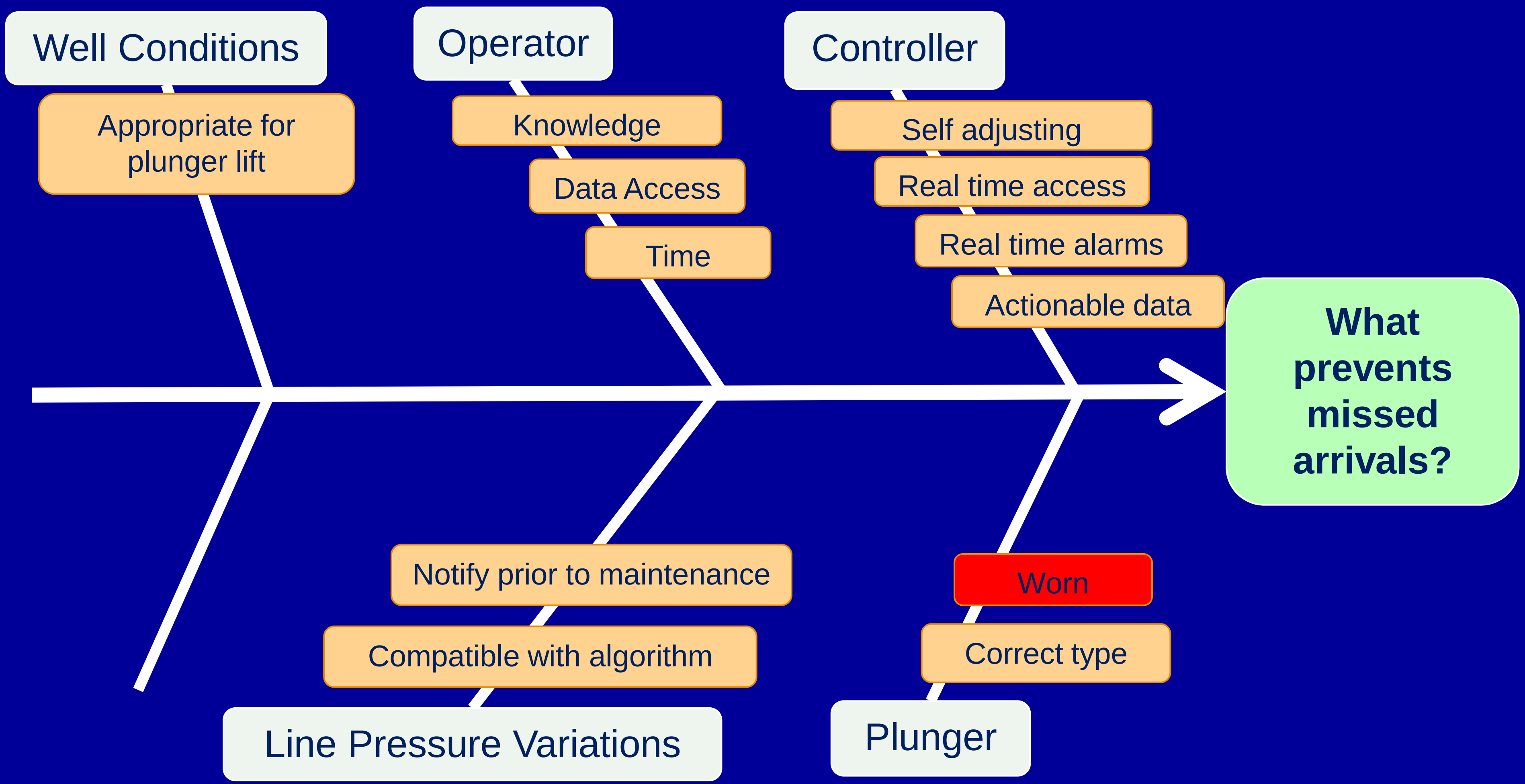
WORK ON THE RIGHT PROBLEM



Optimize many wells

5. Troubleshoot -

SOLVE ROOT CAUSE



Optimize many wells

5. Troubleshoot -

SOLVE ROOT CAUSE

1. **WHY is plunger missing arrivals?**
   - Upward force is insufficient to push plunger to the surface
2. **WHY is upward force insufficient?**
   - No missed arrivals for prior 3 months. Lift pressure and liquid load have not changed. Plunger is worn.
3. **WHY is plunger worn?**
   - Plungers are only replaced when frequent missed arrivals occur, after production declines.
4. **WHY wait until profits are lost?**
   - We have not implemented a preventative maintenance plunger replacement program
5. **WHY don't we have a plunger preventative maintenance program? ? ?**

Optimize many wells

5. Troubleshoot -

SOLVE ROOT CAUSE

"A problem well defined is a problem half solved"

PLAN
Understand the problem

1) Is the problem statement clear and accurate?
2) Has the systemic root cause been identified?

DO
Implement the plan

3) Has irreversible corrective actions been implemented for all root causes?

CHECK
Follow-up

4) Has a plan been identified to verify the effectiveness of all corrective actions?

ACT
Adjust

5) Has a plan been identified to standardize and save all lessons learned across all groups?

Optimize many wells

6. Prioritize daily

Well Names

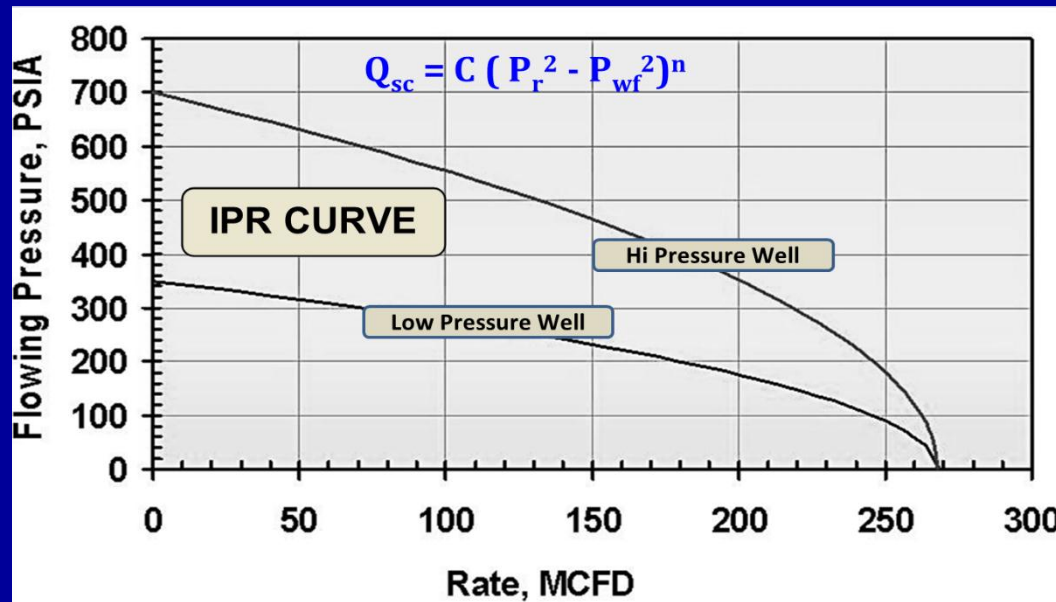
Well Name	Last Polled		Batt.	State	Time	Pressures (psi)			Flow	Velocity	Today			Yesterday			Target	
	Date	Time	Volts		Remain.	Tube	Case	Sales	Rate	(ft/min)	Gas	Arr.	Fails	Gas	Arr.	Fails	Gas	%
	01/26/11	08:42:07	12.8	Plunger Falling	00:06:06	437	497	154	0	477	26	8	0	362	18	0	320	113.1
	01/26/11	08:41:26	11.9	Plunger Falling	00:10:23	354	369	151	0	194	40	4	0	291	13	[illegible]	450	64.6
	12/22/10	09:29:58	11.8	Manual Mode	00:00:00	1	478	0	0	0	0	0	0	0	0	0	0	0.0
	01/30/11	19:09:24	13.1	Manual Mode	00:00:00	-4	465	82	0	0	0	0	0	0	0	0	450	0.0
	01/31/11	08:52:38	12.9	Production Mode	01:48:00	63	174	75	575	529	63	4	0	509	10	0	700	72.7
	01/31/11	09:24:49	13.1	Manual Mode	00:00:00	542	542	56	0	0	3	9	3	350	13	0	0	0.0
	01/28/11	13:39:10	14.1	Plunger Falling	00:20:35	485	641	94	0	887	19	5	1	227	15	3	360	63.0
	01/26/11	08:42:50	13.6	Manual Mode	00:00:00	461	882	53	0	0	0	0	0	0	0	0	340	0.0
	01/31/11	08:51:14	12.8	Plunger Rising	00:34:19	103	482	105	904	1269	78	20	0	693	47	0	700	99.1
	01/26/11	08:41:12	14.5	Production Mode	00:45:19	133	315	147	475	983	71	7	0	588	17	0	775	75.9
	01/26/	[illegible]	[illegible]	[illegible]	03:44:17	115	205	125	512	0	58	0	2	500	0	6	700	71.4
	01/26/	[illegible]	[illegible]	[illegible]	00:11:01	218	238	76	0	867	36	6	0	309	16	0	550	56.3
	01/26/	[illegible]	[illegible]	[illegible]	[illegible]:42	60	168	78	467	1143	51	4	0	422	11	0	600	70.3
	01/26/	[illegible]	[illegible]	[illegible]	00:36:16	94	625	104	352	253	12	3	0	117	8	0	180	65.3
	01/26/	[illegible]	[illegible]	[illegible]	03:06:50	142	408	153	668	0	40	0	2	401	0	5	380	105.5
	01/26/11	08:42:22	12.7	Plunger Rising	00:44:28	161	316	164	1855	1506	36	9	0	363	29	0	390	93.0
	01/26/11	08:42:24	13.6	Plunger Rising	03:39:53	148	428	155	727	0	60	0	2	539	0	5	650	82.9
	01/25/11	10:52:08	11.2	Manual Mode	00:00:00	155	588	150	821	0	75	0	0	541	0	0	650	83.2
	01/25/11	10:52:55	11.5	Plunger Rising	00:23:59	137	418	150	529	1181	81	28	0	397	40	3	500	79.5
	01/21/11	16:28:54	11.5	Manual Mode	00:00:00	1	2	142	0	0	0	0	0	0	0	0	500	0.0
	01/26/11	08:40:20	11.5	Manual Mode	00:00:00	3	-1	148	0	0	0	0	0	0	0	0	600	0.0
	01/26/11	08:41:00	11.6	Plunger Rising	00:55:27	142	473	155	748	1077	15	4	0	129	11	0	180	71.8
	01/26/11	08:41:17	13.8	Production Mode	01:33:42	134	298	148	436	938	58	2	0	481	6	0	600	80.1
	01/31/11	08:52:47	12.9	Production Mode	00:17:24	149	309	156	1174	908	67	12	0	493	30	0	0	0.0
	01/26/11	14:05:23	13.3	Plunger Rising	00:40:33	141	395	152	619	1424	116	15	0	324	8	1	400	81.0
	01/26/11	08:40:34	12.8	Plunger Rising	00:59:47	199	407	177	3991	408	36	4	0	403	13	0	580	69.4
	01/26/11	08:41:38	12.4	Pressure Building	00:00:00	328	332	96	0	0	0	0	0	70	0	14	150	46.4

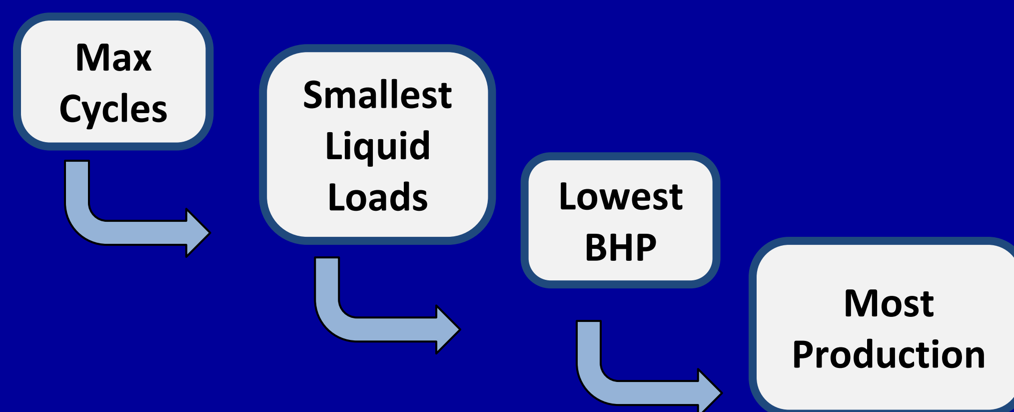
Prioritize before going to well site!

Optimize many wells

7. Produce at lowest flowing bottom hole pressure

- ✓ Know production target
- ✓ Minimize restrictions
- ✓ Select correct plunger
- ✓ Use a standing valve
- ✓ Address well variations with algorithm
- ✓ Review on each cycle
  - ➢ Fluid in tubing
  - ➢ Lift pressure
  - ➢ Plunger velocity
  - ➢ Shut-in time
  - ➢ Gas produced





Optimize

Review

- Time frame after IP
- Critical rate for reservoir
- Decline Curve Analysis
- Erratic production
- Critical flow rate
- Intermittent, Swab, Foam

Clear liquid from tubing first (400 scf per bbl per 1000 ft lift)

Lift Pressure >/= 2X Liquid load

- No Packer (or more gas)
- Same ID spring to spring
- Pressure check tubing

- Motor valve trim size
- Orifice plate
- Consistent line pressure
- Hold down assembly

Is liquid in the tubing? → Is gas volume sufficient ? → Is gas pressure sufficient? → Good well integrity ? → Significant sand, H_2S or CO_2? → Eliminate restrictions

Standard well head configuration defined? → Clean, dry supply gas? → Telemetry available? → Trained operator? → Preventative maintenance program? → Troubleshooting process known (NPT goal vs actual)?

Continuous improvement team established?

Production target set based on % of AOF?

TELEMETRY BENEFITS

- Lower lifting cost
- Less downtime
- Less equipment repairs
- Faster optimization
- Faster troubleshooting
- Improved site safety
- Leverage expert optimizer
- Daily prioritize wells
- Remote manual close
- Alarm on exceptions
- Leak detection

LIFT METHOD	LIFTING COST COMPARISON ($ / Mcf)		
	MIN	MAX	AVG
Gas Lift	$ 1.04	$ 1.30	$ 1.17
Plunger Lift – No Telemetry	$ 0.25	$ 5.80	$ 2.27
Plunger Lift – With Telemetry	$ 0.19	$ 0.90	$ 0.50

OPTIMIZE PRODUCITON

Max cycles → Smallest liquid loads → Lowest bottom hole pressure → Most Production

KNOW NOW. ACT NOW. PROFIT MORE !

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