Chevron

Central Vacuum Unit & Vacuum Grayburg San Andres Unit – OCD Hearing to modify Injection Orders

December 3rd, 2009

BEFORE THE OIL CONSERVATION DIVISION
Santa Fe, New Mexico
Consolidated Case No.'s 14401 & 14402 Exhibit No. 1
Submitted by:
CHEVRON U.S.A. INC.
Hearing Date: December 3, 2009

Three Parts to the Hearing Application-CVU & VGSAU

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- Applying to amend current injection orders in 3 areas:

1. Injection well completion requirements: reason - 9 injectors approved by District don't comply with current injection orders (casing/tubing annulus can't be monitored)
2. Injection packer setting requirements: reason - desire ability to set inj packer higher but still <u>within unitized interval</u>
3. Verbiage around maximum CO_2 injection pressure: reason-desire to reference avg maximum BH injection pressure rather than maximum surface inj pressure <u>in order to respond to reduced injection fluid density</u>

CVU & VGSAU Injection Orders – standard verbiage

- CVU

2

(3) WAG injection operations shall be accomplished through internally coated tubing installed ~~in~~ a packer set within approximately 100 feet of the uppermost injection perforations or casing shoe; the casing-tubing annulus shall be filled with an inert fluid and a gauge or approved leak-detection device shall be attached to the annulus in order to determine leakage in the casing, tubing or packer. 1

(4) For those injection wells within the "EOR Project Area" whose current maximum surface injection pressure for water is less than 1500 psi (as shown on applicant's Exhibit No. 12), the applicant is hereby authorized to inject water into each of these wells at the current maximum surface injection pressure, provided however, such pressure may be administratively increased by the Division upon a showing that such increase will not result in the fracturing of the injection formation or confining strata, and shall be further authorized to inject CO_2 and produced gases at a maximum surface injection pressure of 350 psi above the current maximum surface injection pressure for water, provided however, such CO_2 injection shall not occur at a surface injection pressure in excess of 1850 psi. 3

- VGSAU

2

(4) Enhanced tertiary injection operations shall be accomplished through internally coated tubing installed ~~in~~ a packer set within approximately 100 feet of the uppermost injection perforations or casing shoe; the casing-tubing annulus shall be filled with an inert fluid and a gauge or approved leak-detection device shall be attached to the annulus in order to determine leakage in the casing, tubing or packer. 1

(5) For those injection wells within the enhanced oil tertiary recovery project with a current maximum surface injection pressure for water of less than 1500 psi, the applicant is hereby authorized to inject water into each of these wells at the current maximum surface injection pressure, provided however, such pressure may be administratively increased by the Division upon a showing that such increase will not result in the fracturing of the injection formation or confining strata. The applicant is further authorized to inject CO_2 and produced gases at a maximum surface injection pressure of 350 psi above the current maximum surface injection pressure for water, provided however, such CO_2 and produced gas injection may not occur at a surface injection pressure in excess of 1850 psi. Such pressure may be administratively increased by the Division upon a showing that such increase will not result in the fracturing of the injection formation or confining strata. 3

1) Injection well completion requirements

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" the casing-tubing annulus shall be filled with an inert fluid and a gauge or approved leak-detection device shall be attached to the annulus in order to determine leakage in the casing, tubing or packer."

- Issue around injectors with tubing cemented in place first surfaced in late May, 2009 with VGSAU 47

- CVU 58 - First well remediated this way (2003) after 7 unsuccessful squeeze attempts, CVX and OCD District supervisor met and developed remedial plan and District personnel approved this plan and all subsequent C103's until the VGSAU 47

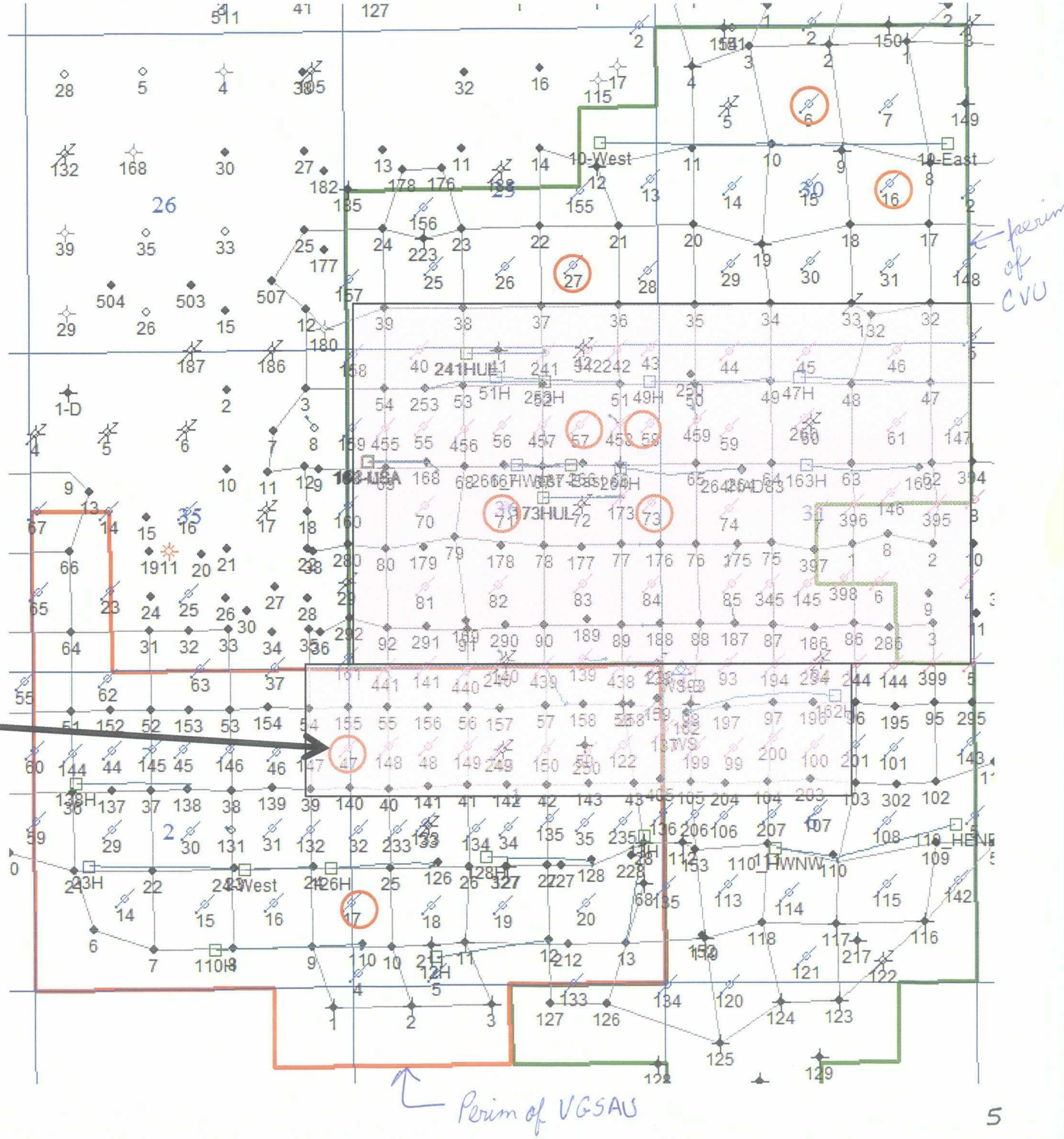
- OCD Santa Fe (7/15/09) - conveyed position that OCD District offices "aren't authorized to grant a variation that violates an OCD order"

- Recent research found a total of 9 New Mexico Chevron injectors completed this way, all at Vacuum following CVU #58

Injector with tubing cemented in place; 7 in CO2 phases are important to reserve recovery

Active CO2 Phase

VGSAU 47 – Shut in on May 22nd following OCD denial of second C103. Eight others remain active as agreed to by OCD UIC examiner Will Jones.



Chevron - Vacuum Field
Cemented Tubing Timeline

Well	Activity	2002	2003	2004	2005	2006	2007	2008	2009
		MJJASOND	JFMAMJJASON		SOND	JFMAM SOND	JFM	MJJAS	MJJASOND
CVU 58	attempt casing repair, Unsuccessful, plan to PA	x x x							
	develop remedial solution w/ OCD Dist 1	x x x							
	implement OCD approved remedial plan		x						
CVU 73	attempt casing repair, Unsuccesful, TA	x							
	submit & receive approval for remedial plan		x						
	implement OCD approved remedial plan		x						
CVU 71	attempt casing repair, Unsuccesful, TA		x						
	submit & receive approval for remedial plan		x						
	implement OCD approved remedial plan		x						
CVU 57	casing repair	x x							
	MIT failure		x						
	submit & receive approval for remedial plan		x						
	implement OCD approved remedial plan		x						
CVU 16	attempt casing repair, Unsuccesful, TA				x x				
	filed intent to P&A				x				
	implement remedial plan, subsequent C-103 approved					x			
CVU 6	attempt casing repair, Unsuccesful, TA				x x				
	submit & receive approval for remedial plan				x				
	implement OCD approved remedial plan					x x			
CVU 27	attempt casing repair, Unsuccesful, TA					x			
	implement remedial plan, subsequent C-103 approved								
	implement OCD approved remedial plan					x x			
VGSAU 17	attempt casing repair, Unsuccesful, TA	x x					x		
	submit & receive approval for remedial plan						x		
	implement OCD approved remedial plan						x		
VGSAU 47	attempt casing repair (2 squeezes), Unsuccesful							x x	
	implement remedial plan, subsequent C-103 approved							x x	
	Subsequent C-103 amended then denied, well shut-in								x
	OCD Hearing								x

Remedial Options & Consequence of Losing wellbores

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- **Remedial Options**
  - Due to the existing string size (7 wells - 2 7/8" and 2 wells - 2 3/8") remedial options are limited & would reduce injection by ~50% and are <u>prohibitively costly</u>
  - Chevron invested >$1.0MM remediating these wells per OCD District office approved plans
- **Consequences of Losing wellbores**
  - Losing the use of these wellbores would result in a loss of ~485 BOPD, <u>2,210</u> MBO proved reserves
  - <u>Loss of ~$19MM in State revenue at $70 BBL</u>
  - ~$15MM cost to replace 9 wells. Due to economic and budgetary constraints most wells would not likely be replaced.

Proposal to Assess & Verify Mechanical Integrity of Injection Wells With Cemented Tubing

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- Test wells to prove mechanical integrity at 5 times the currently required OCD frequency via annual blanking plug tests.
- Monitor for changes in the inj rate versus inj pressure data daily with SCADA
  - Generate alarms prompting human response & evaluation
  - Valid alarms will require shut in
  - Will not resume injection until MIT is confirmed
- Proposed approach fully complies with EPA UIC regulations
  - Approved method in other jurisdictions

2) EPA 40 CFR 146.8

§ 146.8 Mechanical integrity.

(a) An injection well has mechanical integrity if:

(1) There is no significant leak in the casing, tubing or packer; and

(2) There is no significant fluid movement into an underground source of drinking water through vertical channels adjacent to the injection well bore.

(b) One of the following methods must be used to evaluate the absence of significant leaks under paragraph (a)(1) of this section:

(1) Following an initial pressure test, monitoring of the tubing-casing annulus pressure with sufficient frequency to be representative, as determined by the Director, while maintaining an annulus pressure different from atmospheric pressure measured at the surface;

(2) Pressure test with liquid or gas; or

(3) Records of monitoring showing the absence of significant changes in the relationship between injection pressure and injection flow rate for the following Class II enhanced recovery wells:

(i) Existing wells completed without a packer provided that a pressure test has been performed and the data is available and provided further that one pressure test shall be performed at a time when the well is shut down and if the running of such a test will not cause further loss of significant amounts of oil or gas; or

(ii) Existing wells constructed without a long string casing, but with surface casing which terminates at the

Current Operational Overview

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- Aging infrastructure
- Varied construction and maintenance practices
- Corrosive fluids and gases

- Historical legacy events
- Significant exposure in total fluid production, transportation and processing
  - 300,000 BPD Total Fluid
  - 225,000 MCFD

- Systematic elimination of undesirable events
  - Standards in design
  - Facility consolidations and reconstruction
  - Flowline inspections and testing
  - Supervisory Control And Data Acquisition (SCADA) deployment and leak detection development
  - Trunk line evaluation, testing and inspection

Current Operational Overview

- Secondary and Tertiary floods
- Wells range in age up to 70 years old
- 140 injectors (CVU & VGSAU), 57 in CO_2 service
- SCADA deployed in late 1980s
  - Data acquisition
  - Limited control

- Currently assess mechanical integrity by:
  - Monitor annular pressure monthly
  - Annual OCD witnessed Braidenhead testing
  - 5 year OCD witnessed MIT

Chevron – Vacuum Wells With Tubing Cemented in Place

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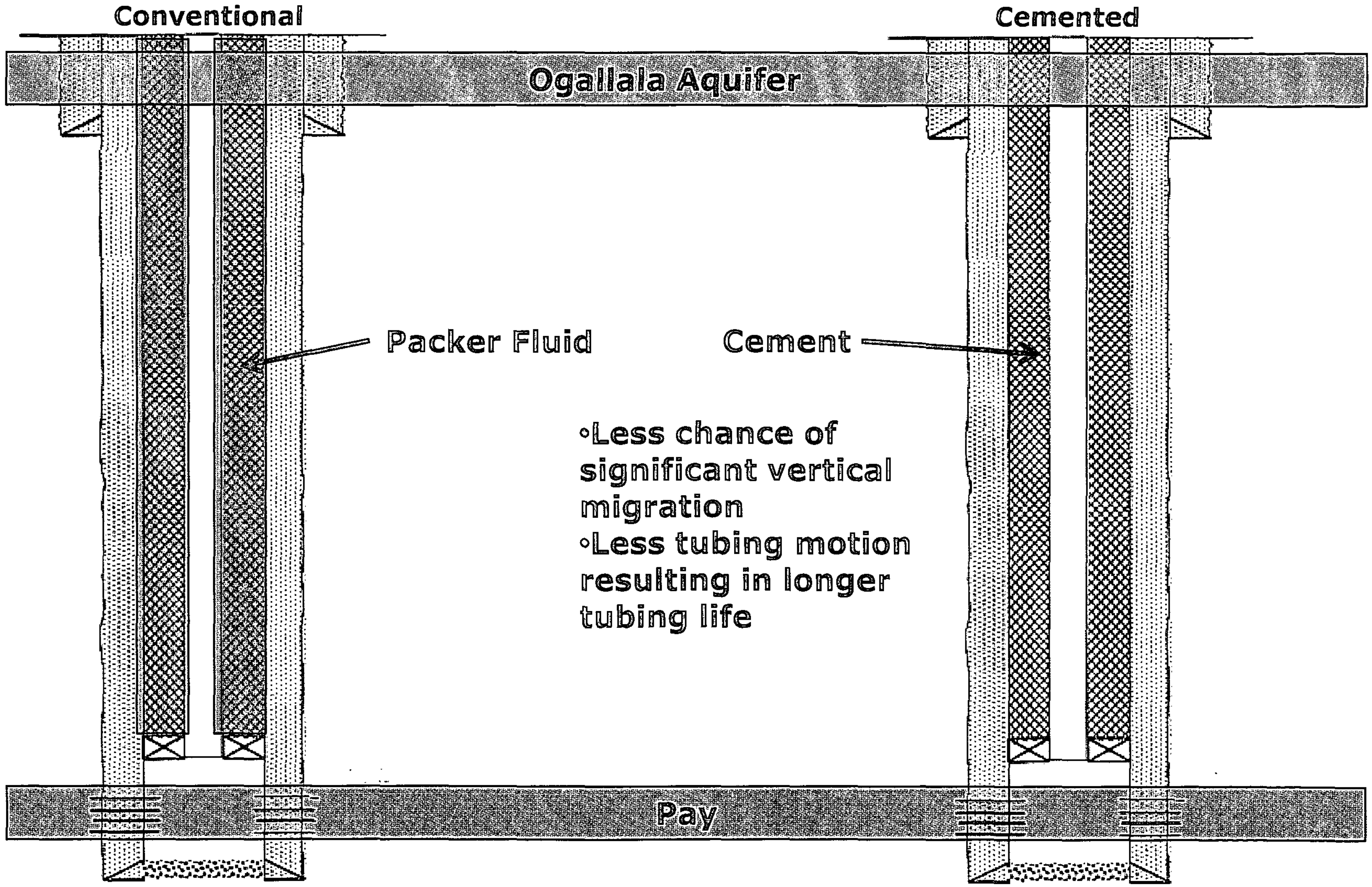
well name	Location (S-T-R)	Surface csg size & depth	Prod csg size & depth	Tubing size & depth	Cemented tubing date	Inj Packer?	2009 tubing MIT test results
CVU 58	36-17S-34E	8 5/8" @ 405 circ cement	4 1/2" @ 4800' circ cement	2 7/8" DL @ 4281' circ cement	Jan-03	yes	10/9 - tested to 2500 psi with good chart
CVU 73	36-17S-34E	9 5/8" @ 409 circ cement	4 1/2" @ 4800' circ cement	2 7/8" DL @ 4281' circ cement	Feb-03	yes	10/21 - tested to 2000 psi with good chart
CVU 71	36-17S-34E	8 5/8" @ 399 circ cement	4 1/2" @ 4800' circ cement	2 7/8" DL @ 4289' circ cement	Aug-03	yes	10/14 - tested to 1750 psi with good chart
CVU 57	36-17S-34E	8 5/8" @ 396 circ cement	4 1/2" @ 4800' circ cement	2 7/8" DL @ 4204' circ cement	Sep-03	yes	10/9 - tested to 2500 psi with good chart
CVU 16	30-17S-35E	8 5/8" @ 413 TOC @ 11'	4 1/2" @ 4870' circ cement	2 7/8" FL @ 4345' circ cement	Feb-06	yes	10/9 - tested to 2500 psi with good chart
CVU 6	30-17S-35E	8 5/8" @ 410 circ cement	4 1/2" @ 4830' circ cement	2 7/8" FL @ 4396' circ cement	Mar-06	yes	10/9 - tested to 2500 psi with good chart
CVU 27	25-17S-34E	8 5/8" @ 420 circ cement	4 1/2" @ 4800' circ cement	2 3/8" FL @ 4341' circ cement	Nov-06	yes	10/12 - tested to 2000 psi with good chart
VGSAU 17	2-18S-34E	8 5/8" @ 364 circ cement	4 1/2" @ 4800' TOC @ 2706'	2 3/8" FL @ 4319' circ cement	Feb-07	yes	10/12 - tested to 2000 psi with good chart
VGSAU 47	2-18S-34E	8 5/8" @ 355 circ cement	4 1/2" @ 4800' TOC @ 2460'	2 7/8" FL @ 4204' circ cement	Jul-08	yes	10/14 - tested to 2000 psi with good chart

30-025-24316

30-025-24365

Wellbore Comparison



- Less chance of significant vertical migration
- Less tubing motion resulting in longer tubing life

Mechanical Integrity Testing

Mechanical integrity Tests Performed on the Nine Project Wells in October 2009. All Wells Showed Mechanical Integrity

- Rigged up pump truck and flushed tubing with fresh water
- Rig up Slick Line Unit and run in hole with gauge ring to profile nipple verifying no restrictions.
- Run in hole with blanking plug on slick line. Set plug in profile nipple.
- Opened well to pump truck to bleed off pressure on tubing to verify plug is set (tubing pressure bleed off to zero)
- Perform pressure test of tubing. Test pressure varied. Initial wells were tested at 2500 PSI. Reduced targeted test pressure to 2000 PSI.
- Ran charts to document test results.
- Retrieve blanking plug
- Return well to normal operations

- Issues: CO_2 in Tubing – Check Valve Failures – No Local Isolation Valve – Risk of damaging liner or Profile Nipple

Lessons Learned From Blanking Plug MIT

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- Wells that are on CO_2 will need to be wagged to water for several days prior to testing. CO_2 cannot be effectively swept out of the tubing with a single flush
- Test fluid should be fresh water
- Existing wellhead installation will need to be modified to include an isolation valve, figure eight blinds and local bleed off valves on both sides of isolation valve. Modification will eliminate leaking check valve issues that were identified during initial testing.
- Schedule and execute tests of all project wells during same test period to enable efficient utilization of service company and site supervision
- Attempt to schedule same service company personnel with each test.

Proposed MIT Test Procedure

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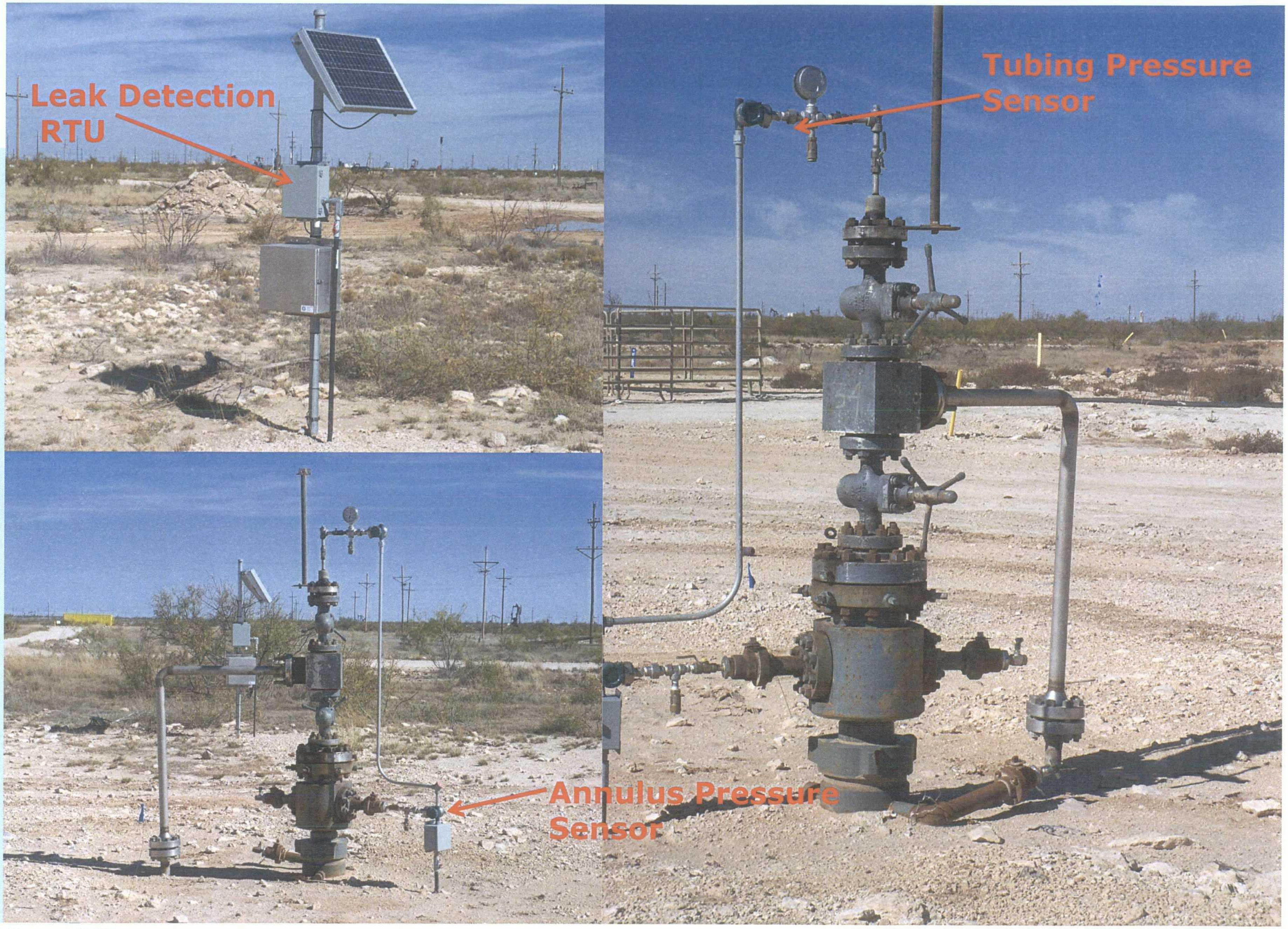
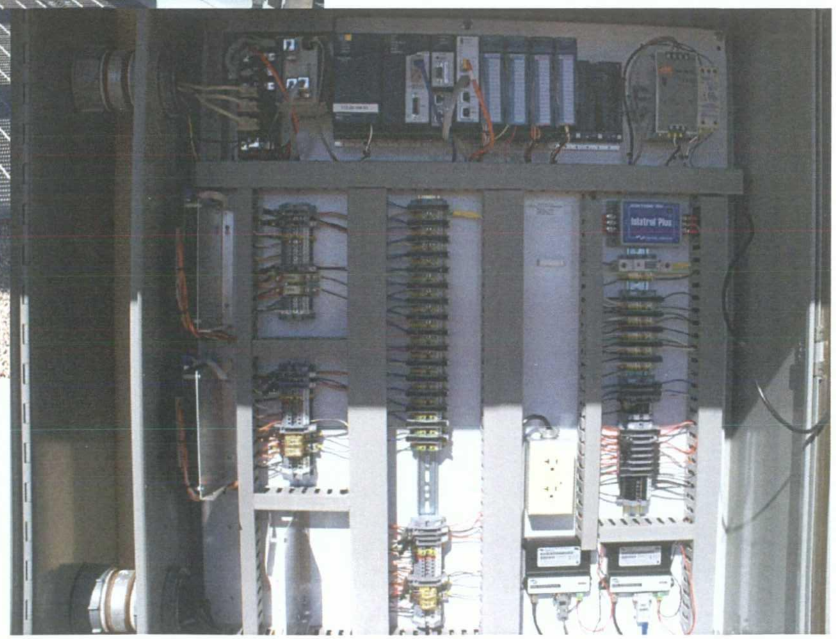
NMOCD District Office Notification and Witness Opportunity Required

- ☐ Ensure well has been on water injection for minimum of five days prior to test date
- ☐ Document normal operating injection pressure prior to initiation of test
- ☐ Close isolation valve and position the figure eight blind in the closed position
- ☐ Rig up Slick Line Unit and run in hole with appropriate sized gauge ring and bailer. Tag PBTD and document depth to top of fill. Stroke bailer to obtain fill sample.
- ☐ Rig up pump truck and flush the tubing with fresh water. Pump 150% tubing displacement.
- ☐ Run in hole with blanking plug and set in the profile nipple.
- ☐ Open tubing and attempt back flow to pump truck (tubing should bleed off)
- ☐ Perform pressure test of tubing and profile nipple seal to appropriate pressure based on differential pressure and gradient correction.
- ☐ Chart the test as per NMOCD process guidance (default will be 24 hour chart and 96 minute clock). Obtain signatures of tester and witnesses.
- ☐ Retrieve blanking plug
- ☐ Return figure eight blind to open position
- ☐ Return well to normal operations


Leak Detection
RTU
Tubing Pressure
Sensor
Annulus Pressure
Sensor

Typical Injection Header and Programmable Logic Controller



Surveillance – Alarm Monitoring – Initial Response

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Surveillance and Alarm

- ❑ Daily review of SCADA pressure and flow rate trend data for the project wells
- ❑ Operating condition inclusion in daily alarm report ("Normal / Alarm")
- ❑ Call out alarm if deviation triggers have been exceeded for determined time period not to exceed 24 hours.

Alarm Response

- ❑ Review trend data with Operations Supervisor (OS) or Production Team Lead (PTL) the same day as alarm is received
- ❑ Conduct on sight investigation to verify integrity of measurement equipment (*Priority Level 1 Response ... same as reportable spill to surface*)
- ❑ Conduct on sight investigation to identify if surface leak may exist (*Priority Level 1 Response ... same as reportable spill to surface*)
- ❑ Shut well in and make notifications to OS if subsurface leak is suspected based upon investigation findings.
- ❑ OS will provide notification to NMOCD District office of Possible loss of mechanical integrity (*Priority Level 1 Response ... same as reportable spill to surface*)
- ❑ OS will having blanking plug installed and conduct mechanical integrity as per procedure including NMOCD witness.

Proposed plugging program – 2 7/8" Slimhole injection wells

1. Evaluate and prep location.
2. MIRU Sunset Well Service, Inc. plugging equipment. RIH with 2-1/16" workstring and spot cement from original production casing shoe or top perforation to TOC ±2,700' on original production casing. WOC & TAG, displace hole w/MLF.
3. RIH w/wireline and perforate 100' below Base of Salt. POH w/wireline. Establish injection rate. Cement squeeze 200' inside 2-7/8" liner and 200' outside original production casing. WOC & TAG.
4. RIH w/wireline and perforate 100' below Top of Salt. POH w/wireline. Establish injection rate. Cement squeeze 200' inside 2-7/8" liner and 200' outside original production casing. WOC & TAG.
5. RIH w/wireline and perforate 100' below surface casing shoe. POH w/wireline. Establish injection rate. Cement squeeze from surface and circulate cement to surface outside original production casing.
6. RDMO Sunset Well Service, Inc. plugging equipment.
7. Install dryhole marker, clean location and turnover for surface remediation operations.

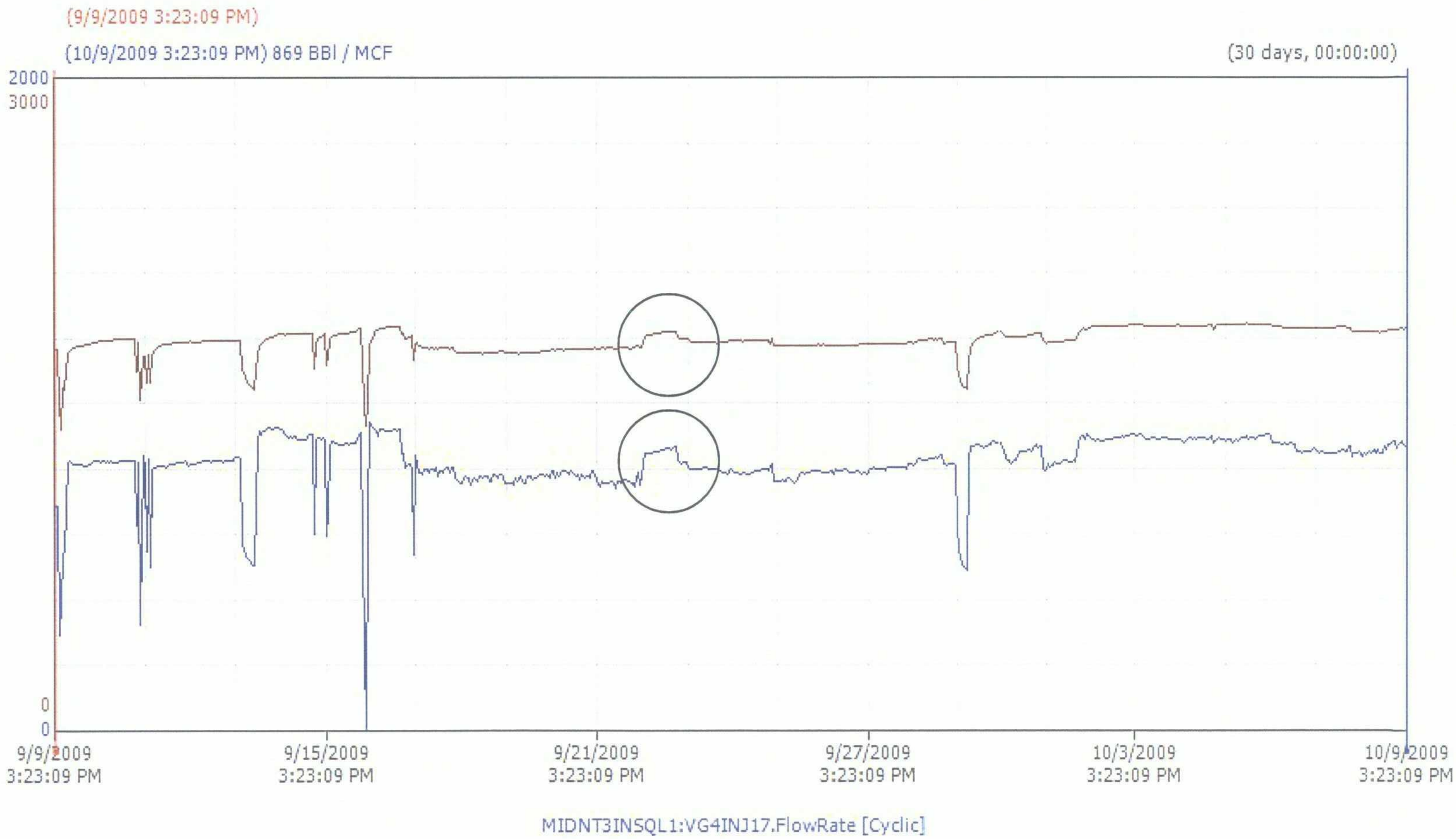
Proposed plugging program – 2 3/8" Slimhole injection wells

Chevron

1. Evaluate and prep location.
2. MIRU CTU. RIH w/1-1/4" CT and spot cement plug from original production casing shoe or top perforation to TOC ±2,700' on original production casing. WOC & TAG, displace hole w/MLF.
3. Pressure test 2-3/8" liner to 2,000 psig. RDMO CTU. MIRU Sunset Well Service, Inc. plugging equipment.
4. RIH w/wireline and perforate 100' below Base of Salt. POH w/wireline. Establish injection rate. Cement squeeze 200' inside 2-3/8" liner and 200' outside original production casing. WOC & TAG.
5. RIH w/wireline and perforate 100' below Top of Salt. POH w/wireline. Establish injection rate. Cement squeeze 200' inside 2-3/8" liner and 200' outside original production casing. WOC & TAG.
6. RIH w/wireline and perforate 100' below surface casing shoe. POH w/wirleline. Establish injection rate. Cement squeeze from surface and circulate cement to surface outside original production casing.
7. RDMO Sunset Well Service, Inc. plugging equipment.
8. Install dryhole marker, clean location and turnover for surface remediation operations.

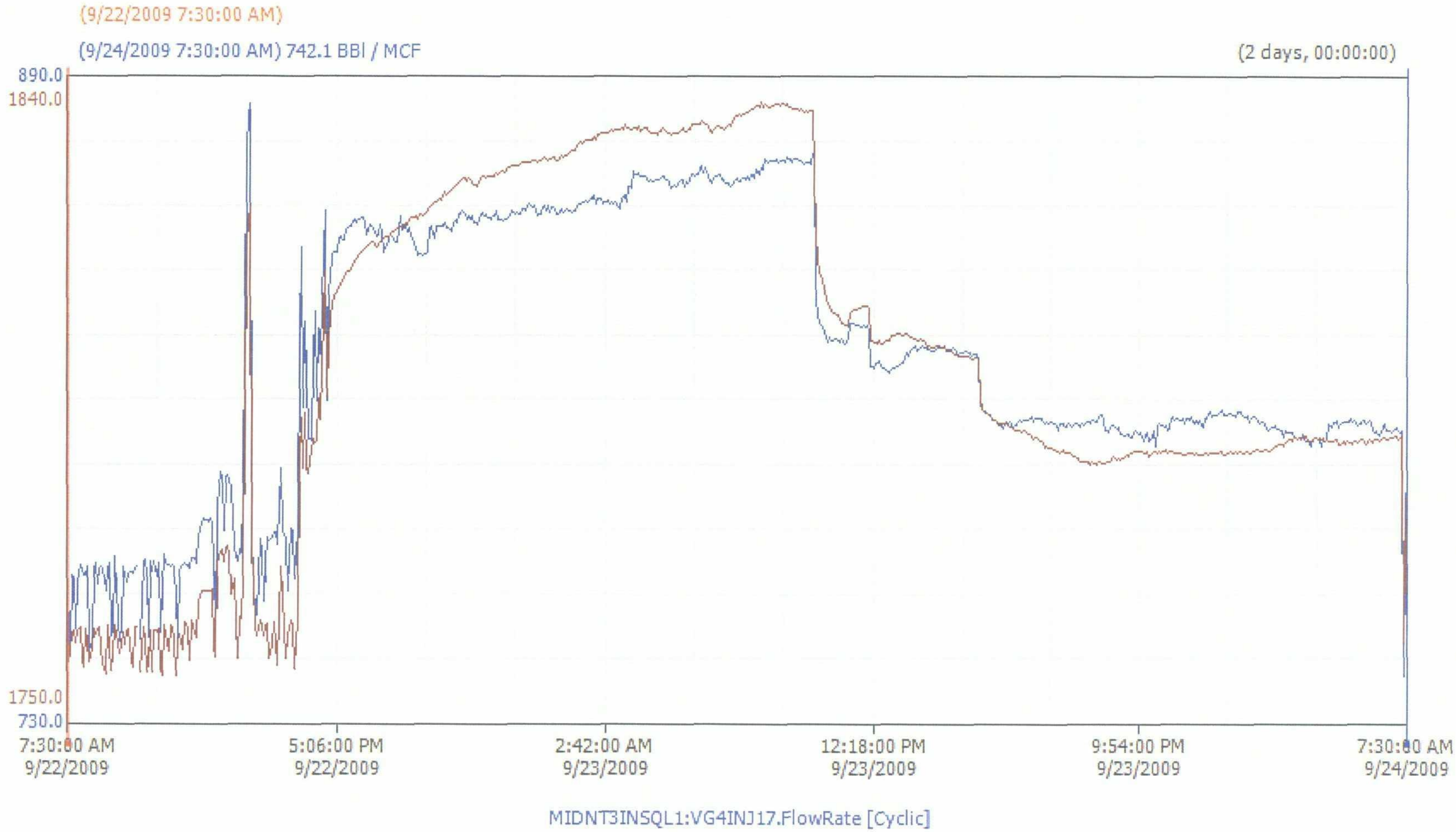
NOTE: If 2-3/8" liner does not test and requires cement squeeze or cement spot plug then work will be done w/1-1/4" jointed tubing.

VGSAU 17 30 Day Rate and Pressure



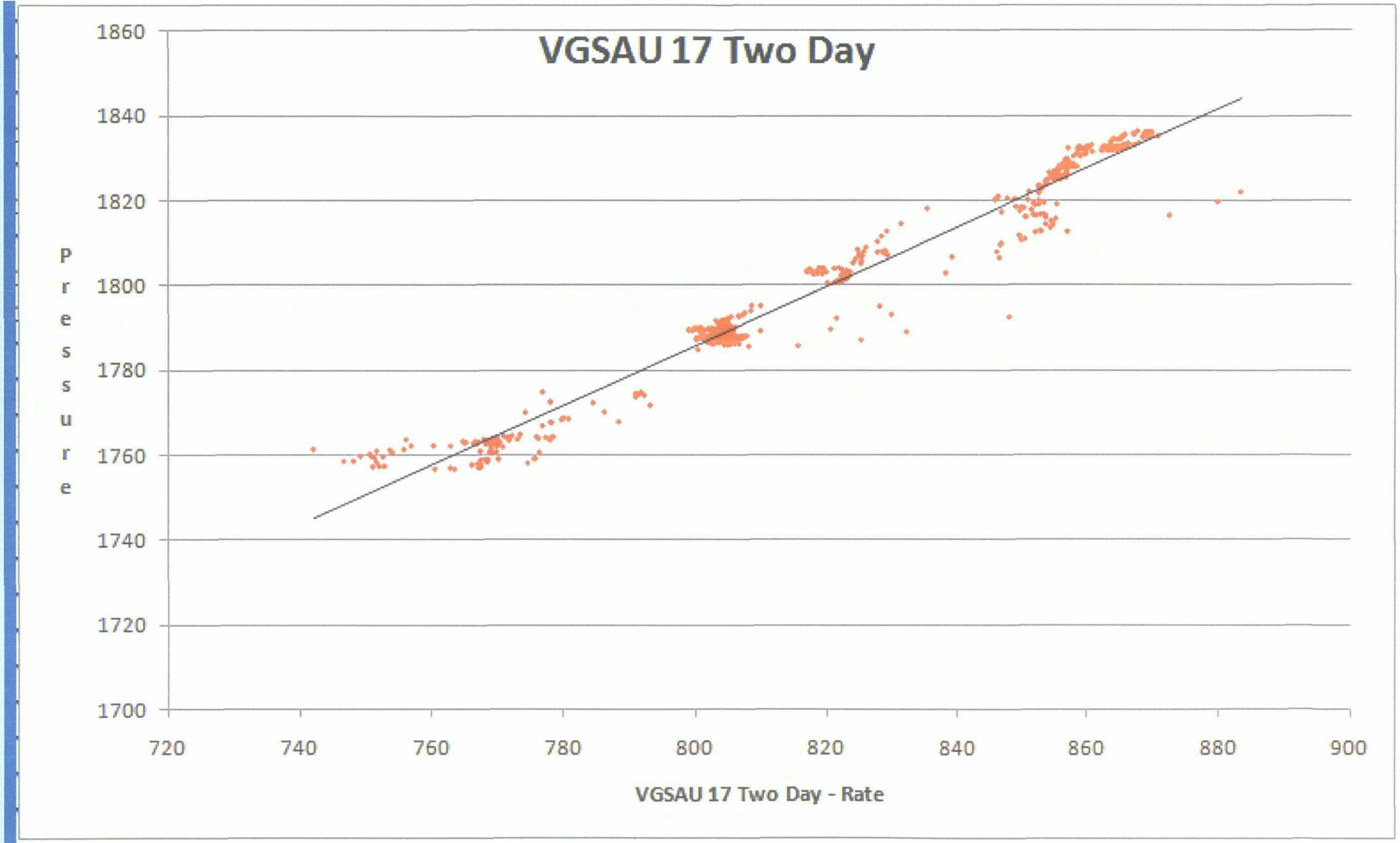
Tag Name	Description	Server	Color	Units	Minimum	Maximum	IO Address	Time Offset
VG4INJ17.FlowRate	CVX Injection Well	MIDNT3I...		BBl / MCF	0	2000	\\MIDNT3INSQL1\InS...	0:00:00.000
VG4INJ17.TubingPsi	CVX Injection Well	MIDNT3I...		psi	0	3000	\\MIDNT3INSQL1\InS...	0:00:00.000

VGSAU 17 2 Day Rate and Pressure

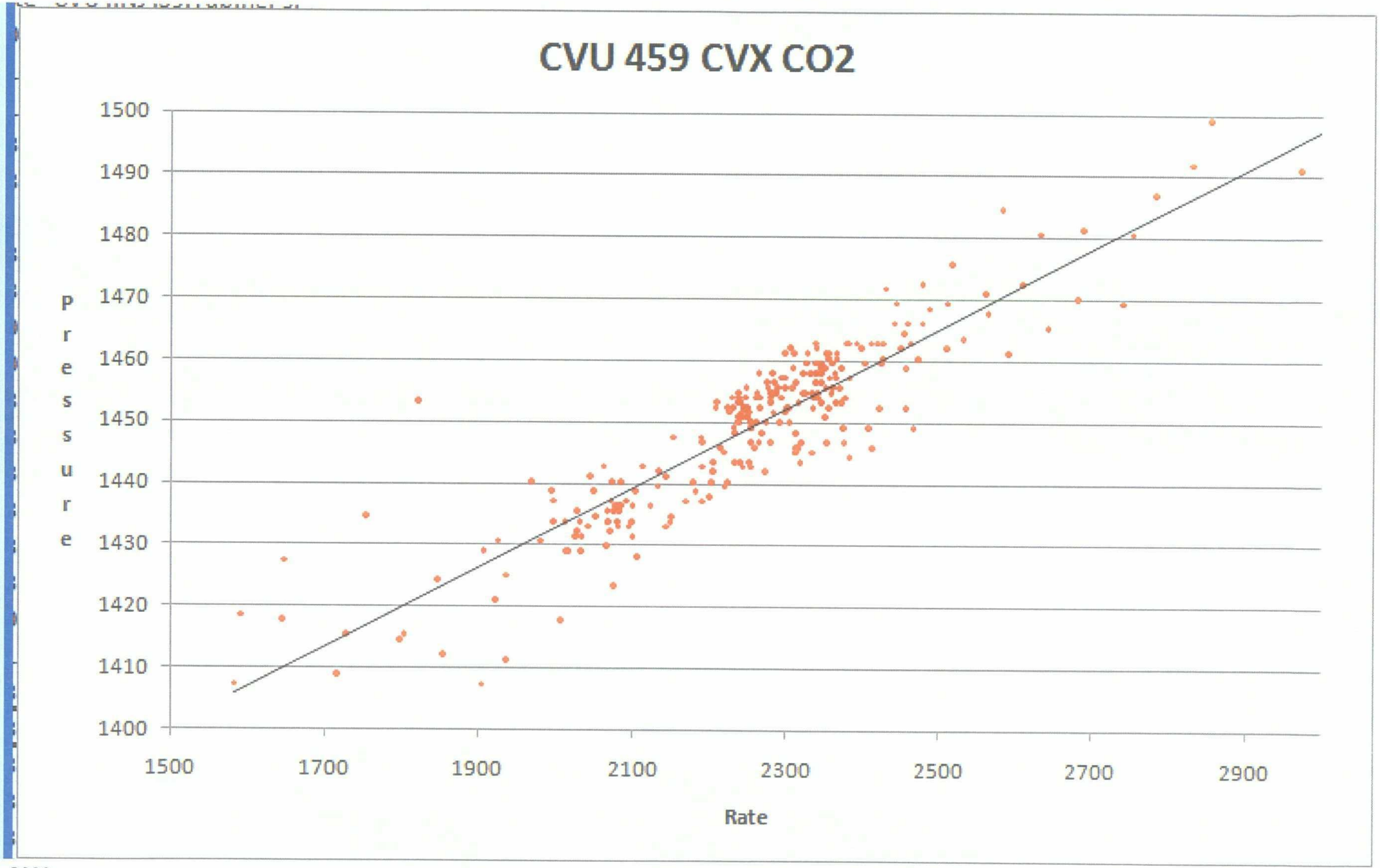


Tag Name	Description	Server	Color	Units	Minimum	Maximum	IO Address	Time Offset
VG4INJ17.FlowRate	CVX Injection Well	MIDNT3I...		BBl / MCF	730.0	890.0	\\MIDNT3INSQL1\InS...	0:00:00.000
VG4INJ17.TubingPsi	CVX Injection Well	MIDNT3I...		psi	1750.0	1840.0	\\MIDNT3INSQL1\InS...	0:00:00.000

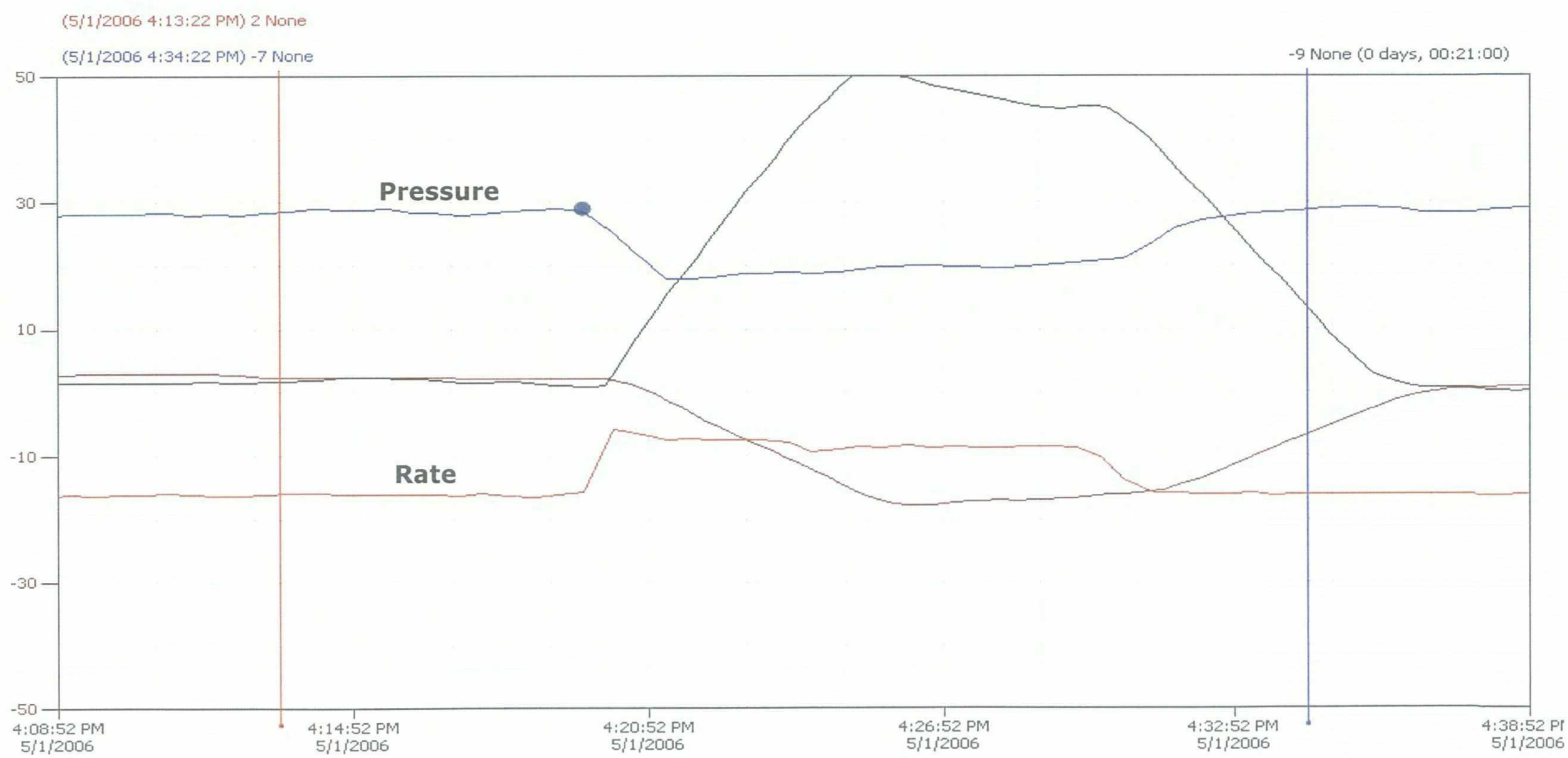
VGSAU 17 2 Day Rate Versus Pressure



CVU 459 2 Day Rate Versus Pressure



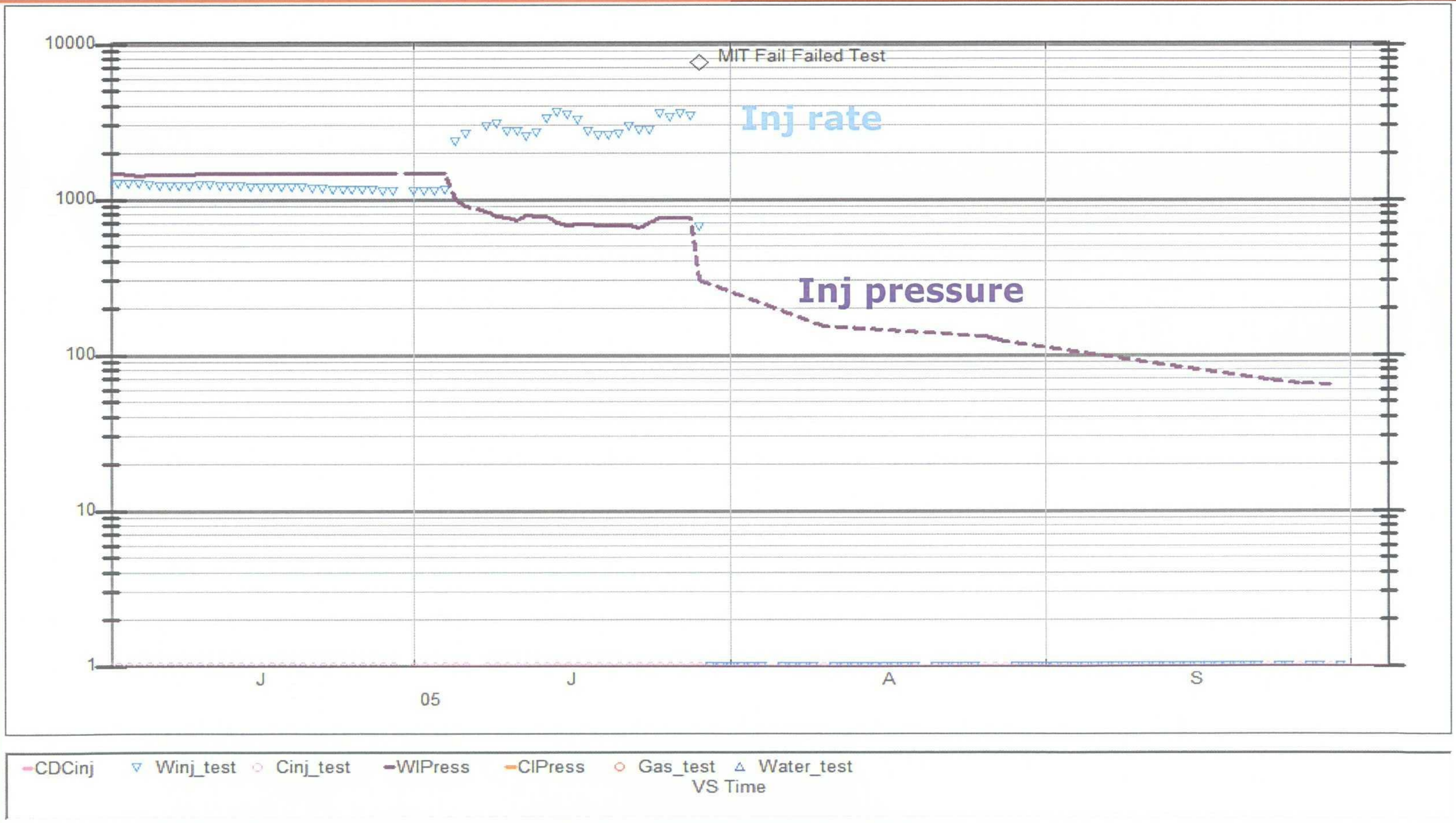
Typical Leak Profile
Rate Rising – Pressure Falling



CVU 27 MIT Failed

Name: CVU 027 ID: 30025258150001 Type: Completion Format: [p] Comp - Prod_Inj vs Time

WELL_LABEL:CVU 027	FIELD_CODE:T49	PROD_METH:IJ	LASTOCUM:0
CHEVNO:EQ0048	FIELD:FLD-VACUUM	CLASS_CODE:WI	LASTGCUM:0
SIDETRACK:0	LEASE:CENTRAL VACUUM U	SAP_CODE:BCT494500	CC_NM:CENTRAL VACUUM UNIT
COMP_NUM:01	SEC-T-R:25 - S017 - E034	RES_CODE:0000006849	RES:GRAYBURG/SAN ANDRES



2) Injection packer setting requirements

" WAG injection operations shall be accomplished through internally coated tubing installed in a packer set within approximately 100 feet of the uppermost injection perforations or casing shoe; "

- Once an injection packer is released for remedial actions, we often can't regain a packer seat at the same depth due to corrosion, must reset packer higher: This often requires the packer to be greater than the approved "100' of top perf"
- As a result, practical practice has evolved to the Operator shutting down operations, contacting the District office and asking for a waiver, which are commonly granted (verbal or written).
- This delay costs time & money and based on July 15th Santa Fe communication the District offices can't approve anyway

2) Chevron CVU & VGSAU wells with high packers

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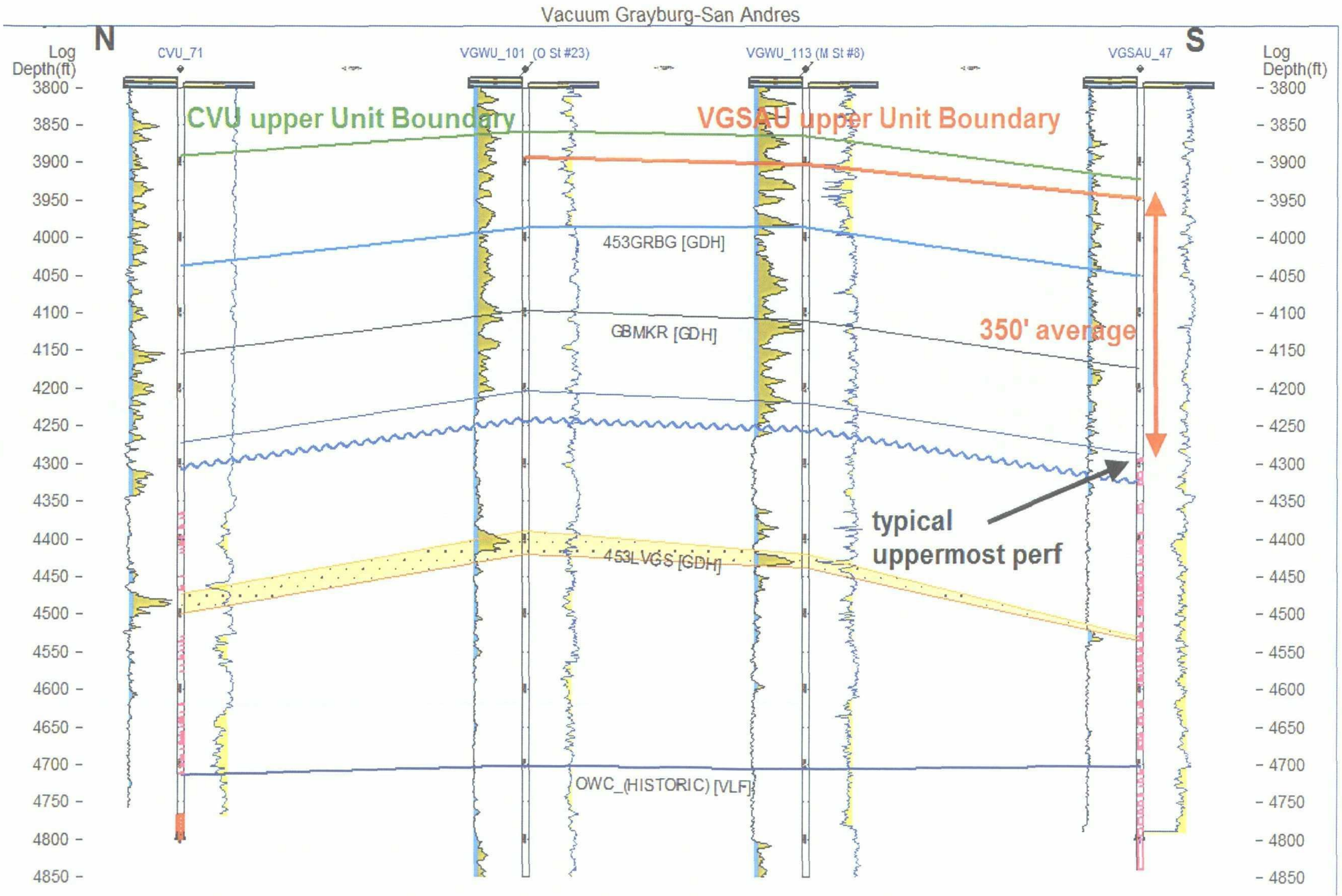
well	Packer height above top perf	Unit top height above packer
CVU 14	136	442
CVU 28	139	406
CVU 31	108	341
CVU 46	121	373
CVU 56	151	332
CVU 70	103	397
CVU 82	143	317
CVU 83	121	310
CVU 93	118	270
CVU 115	193	283
CVU 133	165	376
CVU 134	190	296
CVU 146	120	352
CVU 155	285	184
CVU 156	102	369
CVU 158	291	198
CVU 160	104	358
VGSAU 4	123	256
VGSAU 14	103	202
VGSAU 15	294	106
VGSAU 19	211	270
VGSAU 29	164	218
VGSAU 30	252	96
VGSAU 31	212	126
VGSAU 34	165	208
VGSAU 45	193	207
VGSAU 59	121	228
VGSAU 60	106	299
VGSAU 65	121	288
VGSAU 148	101	213
VGSAU 233	105	297

- ❑ 31 wells with packers >100’ above top perf or casing shoe
- ❑ 38 more injectors with packer from 75’ to 100’ above top perf; next well work will likely result in packer being >100’ above top perf.

2) Vacuum Field N-S Cross Section with Unit Boundaries



2) Injection packer setting requirements

Chevron

WAG injection operations shall be accomplished through internally coated tubing installed in a packer set within approximately 100 feet of the uppermost injection perforations or casing shoe; "

- Since CVU & VGSAU upper Unit boundaries are ~350' above top perf, propose to amend verbiage to allow setting the injection packer "as close as possible to the uppermost injection perforations or casing shoe, <u>so long as it remains within the unitized interval</u>"
- This change will still fully protect other formations and correlative rights
- Fed UIC regulations do not limit injection packer setting depths, they even allow injection without a packer

2) EPA 40 CFR 146.8

§ 146.8 Mechanical integrity.

(a) An injection well has mechanical integrity if:

(1) There is no significant leak in the casing, tubing or packer; and

(2) There is no significant fluid movement into an underground source of drinking water through vertical channels adjacent to the injection well bore.

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(2) Pressure test with liquid or gas; or

(3) Records of monitoring showing the absence of significant changes in the relationship between injection pressure and injection flow rate for the following Class II enhanced recovery wells:

(i) Existing wells completed without a packer provided that a pressure test has been performed and the data is available and provided further that one pressure test shall be performed at a time when the well is shut down and if the running of such a test will not cause further loss of significant amounts of oil or gas; or

(ii) Existing wells constructed without a long string casing, but with surface casing which terminates at the

3) Maximum CO2 injection pressure

" and shall be further authorized to inject CO_2 and produced gases at a maximum surface injection pressure of 350 psi above the current maximum surface injection pressure for water, provided however, such CO_2 injection shall not occur at a surface injection pressure in excess of 1850 psi.

- Both CVU & VGSAU Injection orders tie maximum CO2 injection pressure back to a surface pressure, yet the OCD allows this value to tie to an average maximum BH pressure (i.e. ConocoPhillip's EVGSAU)
- Similar verbiage for our Units would allow Operations to mitigate BHIP drops created by injection stream density reductions due to Hc gas contamination, which greatly reduces our effective BHIP (impact is ~400 psi @ 87% CO2).

3) Buckeye Plant Recycle Gas Analysis

MOBILE ANALYTICAL LABORATORIES, INC.
P.O. BOX 69210
ODESSA, TEXAS 79769
PHONE (432)337-4744

8764

ANALYSIS REPORT

COMPANY . .	CHEVRON U.S.A.	STATION	
LEASE/PLANT	CO2 BACK TO FIELD	PRESS. PSIG . . .	800
OPERATOR .	BUCKEYE	TEMP. DEG. F . . .	104
CYLINDER .	0139	SAMPLED / RECEIVED	10/22/09
H2S PPM . .	4148.0	SAMPLED BY . . .	SR

FRACTIONAL ANALYSIS

COMPONENT	MOL %	GPM C3+	GPM C5+
NITROGEN	1.782	0.000	0.000
CARBON DIOXIDE . .	87.032	0.000	0.000
METHANE	4.208	0.000	0.000
ETHANE	2.506	0.000	0.000
PROPANE	1.726	0.473	0.000
ISO-BUTANE	0.281	0.091	0.000
N-BUTANE	0.816	0.256	0.000
ISO-PENTANE	0.294	0.107	0.107
N-PENTANE	0.299	0.108	0.108
HEXANES PLUS . . .	0.641	0.278	0.278
H2S	0.415	0.000	0.000
TOTALS	100.000	1.313	0.493

CALC. SP.GRAVITY 1.486

BTU/CU. FT. (14.650 PSIA, 60 DEG. F)
CALC. GROSS WET 222
CALC. GROSS DRY 226

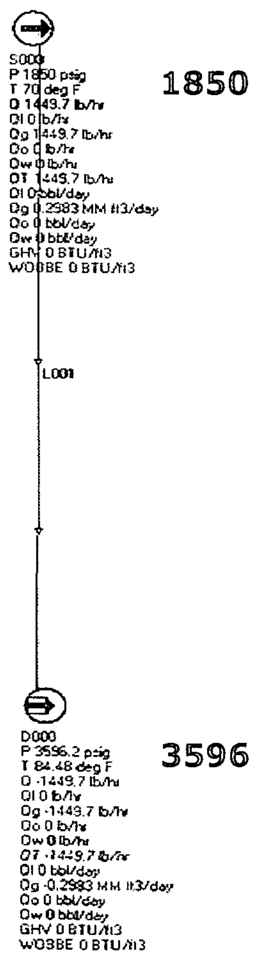
DISTRIBUTION:
MR. MARK GARNER

NOTES:
SPOT

3) Pipephase calculation table

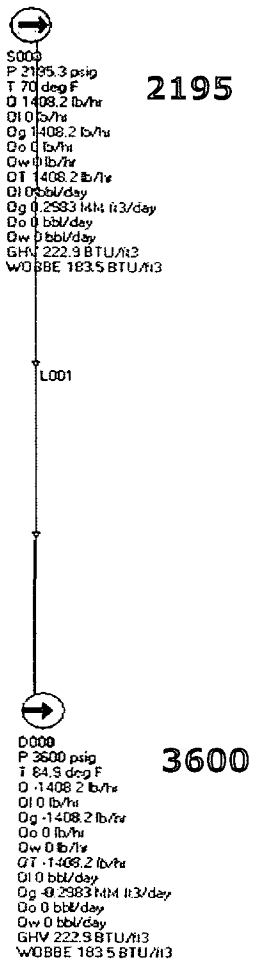
100% CO2 (1850# & 4550')

Fixed Surface Pressure = 1850#



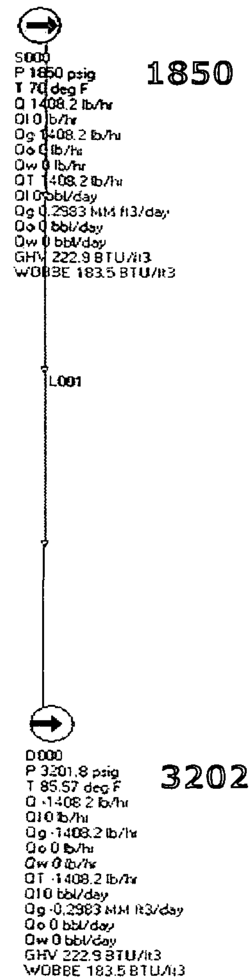
87% CO2 (3600# & 4550')

Fixed Bottom Hole Injection Pressure = 3600#



87% CO2 (1850# & 4550')

Fixed Surface Pressure = 1850#



3) Recycled CO2 Bottom Hole Pressure Effects

Chevron

Surface Pressure, Psi	1,850	1,850	2,195
% CO2	100	87	87
Bottom Hole Pressure, PSI	3,596	3,202	3,600

To maintain the desired & permitted bottom hole pressure with recycled CO2, allowing Chevron to efficiently manage the tertiary recovery of hydrocarbons from these Units:

- Chevron requests a CO2 average (mid-perf) maximum bottom hole injection pressure of 3600psi,
- or an increase in the maximum surface injection pressure to 2200psi (an increase of 350 psi over the current limit)