UIC - I - ___8___

EPA FALL-OFF TEST PLAN

DATE:

2008 - Present

Chavez, Carl J, EMNRD

From: Chavez, Carl J, EMNRD
Sent: Thursday, November 15, 2012 3:33 PM
To: 'Holder, Mike'
Subject: RE: WDW-1, 2 & 3 Fall-Off Test (FOT) Plan

Mike:

The New Mexico Oil Conservation Division (OCD) has reviewed Navajo Refining Company, LLC's response(s) to the above subject plan.

In brief, NRC may submit a new Fall-Off Test Plan (FOTP) to the OCD for review and approval, if it wishes to do so after reviewing OCD's comments, recommendations and/or requirements below.

Please see the OCD responses to questions and/or comments in red italicized font below. Please contact me to communicate or if you have questions.

Thank you.

Carl J. Chavez, CHMM
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Oil Conservation Division, Environmental Bureau
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"Why Not Prevent Pollution; Minimize Waste; Reduce the Cost of Operations; & Move Forward With the Rest of the Nation?" To see how, please go to: "Pollution Prevention & Waste Minimization" at http://www.emnrd.state.nm.us/ocd/environmental.htm#environmental

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From: Holder, Mike [mailto:Mike.Holder@hollyfrontier.com]
Sent: Wednesday, November 14, 2012 5:11 PM
To: Chavez, Carl J, EMNRD
Cc: Holder, Mike
Subject: FW: WDW-1, 2 & 3 Fall-Off Test (FOT) Plan

Carl - attached are the responses prepared by NRC/SubSurface to your email below. I think they may be somewhat superseded by our conversation today but wanted to go ahead and send and we can further discuss (I ran out of time today to call you back but will review the docs we discussed and get back to you). One question is whether we need to actually resubmit if we go back to the approved plan but I did think we needed to address your concerns.

It would be less expensive and labor intensive to continue to utilize the approved Fall-Off Test Plan (FOTP), since the FOTP was developed based on the UIC Guidance and should allow NRC the flexibility it needs to complete FOTs today. OCD appreciates the responses in this e-mail, which serve to document concerns and resolution of concerns on paper. Some responses seem to indicate a new FOTP will be submitted for OCD approval, which the OCD would review to make sure that it is approvable. The OCD did not approve subsequent FOTPs from NRC because at the time the basis for submittal appeared to be minimizing the frequency of FOTs. However, as you mention NRC was attempting to comply with what it interpreted to be *submittal of a FOTP for each well prior to conducting every FOT. This is not the case; therefore, it is NRC's decision to submit a new FOTP for WDWs 1, 2 and 3 for OCD review and approval.*

Thanks again for all your help.

Mike

New Mexico OCD Questions and Comments about 2012 Test Plan (Revised 11-14-12)

Observations and/or Comments:

1) OCD recently determined that for the NRC's 3 Class I (NH) Injection Wells that it will stagger the frequency of well FOTs to be performed at least once every 3 years per well in order to allow either 1 well FOT per year or the option to perform 1 well FOT on all 3 wells at least every 3 years.

   Agreed.

2) Page 3 Section III: Only one OCD approved Fall-Off Test Plan (FOTP) is required and OCD currently acknowledges the original FOTP as the official version in place to date.

   NRC was under the impression that a test plan must be submitted annually as per Section III in the Test Plan which states "a plan for conducting the test shall be submitted to OCD for review and approval prior to conducting the test." Per discussions with OCD, NRC will locate and review the approved FOTP for use in the future, as well as review the December 3, 2007 Fall-Off Test Guidance. If modifications are required we will contact OCD.

   OCD's intent was not to require a FOTP for each well prior to performing every FOT, but to approve one FOTP per well or all wells that basically adheres to the UIC FOT Guidance developed in December 3, 2007.

3) Page 10 #4b: NRC appears to be decreasing the injection rate to minimize the total volume of injection fluid required to complete a well FOT and possibly to demonstrate a minimum pressure differential in the injection zone of 100 psig is achieved during any given FOT.

   There is a calculation along with historical FOT flow rate and volume information for NRC to estimate the minimum volume of injection fluid needed at each well location to achieve a pseudo steady-state injection rate and achieve a radial flow condition before pump shut-off and FOT monitoring. NRC and OCD should be working to determine the actual injection zone capacity and not attempting to engineer FOTs to achieve minimum pressure differential criteria. However, any other reason for minimizing the total volume of injected fluid is not valid.

   The 100 psi differential referenced in the 2012 Test Plan is the difference between the injection pressure prior to shut-in and the pressure at the end of the falloff period. The injection rates are adjusted and maintained during the injection period so a valid observation of radial flow can be made during the falloff period. The tests are also designed to demonstrate the actual maximum differential pressure achieved during injection. The rates are not adjusted to minimize the volume of fluid injected. The reference to the 100 psi differential pressure will be removed from the 2012 Test Plan.

No changes needed if NRC relies on the approved FOTP.

Let us work on building up the pressure in the injection interval to monitor the actual capacity of the injection interval to accept oilfield fluid wastes and not worry about the 100 psig differential in comparison with the P(false extrapolated P value), etc. Thank you.*

Requirements:

1) Page 11 #7: Bottom hole gauges shall be emplaced and monitored in offset wells during well FOTs if NRC wishes to prove Section XI is true. Otherwise, please remove Section XI. OCD discussions with subsurface well experts indicates that due to the spatial distance and hydrogeological variability between NRC wells and site-specific injection zones, installation of bottom hole pressure gauges would likely not prove interconnection between NRC wells.

   Section XI will be removed from the 2012 Test Plan.

Ok, or if NRC relies on the approved FOTP, this is not an issue. Thank you.

2) Page 12 #10: WDWs were recently stimulated with acid in coiled tubing. Please confirm that a C-103 Sundry Notice was submitted to the OCD for approval in advance of the well work.

   A C-103 Sundry Notice was not submitted to the OCD prior to the acid stimulation work; however the OCD was notified via email. From NM OCD guidelines, remedial work requires a C-103 Sundry Notice but it is our understanding that acid stimulation does not classify as remedial work. A C-103 Sundry Notice for the acid stimulation work will be submitted to the OCD upon request.

The discharge permit requires that a C-103 Sundry Notice be submitted for approval and notification of work in order for OCD to witness the well work. NRC has been very good about notification; therefore, a C-103 submittal is not requested. Please be advised of the new discharge permit renewal language requirement below.

3.F. WELL WORKOVER OPERATIONS: Pursuant to 20.6.2.5205A(5) NMAC, the Permittee shall provide notice to and shall obtain approval from OCD's Environmental Bureau prior to commencement of any remedial work or any other workover operations to allow OCD the opportunity to witness the operation. The Permittee shall request approval using form C-103 (Sundry Notices and Reports on Wells) with copies sent to OCD's Environmental Bureau and Artesia District Office.

3) Page 13 #15: FOTs shall not be designed to achieve the minimum 100 psig pressure differential. The FOT should demonstrate the actual maximum pressure differential from pressure buildup through injection into the injection zone. The FOT should demonstrate the actual injection zone ability to receive injected fluids.

   See "Item 3" in "Observations and/or Comments"

4) Page 20 #5: Same as No. 3 above.

   See "Item 3" in "Observations and/or Comments"

5) Page 22 #4: The "h" injection interval value used for each well during the FOT shall be based on the footage of the perforated injection interval(s) per well. If NRC disagrees, could you please provide the h values and basis for using a different "h" value per well for FOT calculations.

   WDW-1: Perfs = 253 ft; h = 175 ft

   WDW-2: Perfs = 299 ft; h = 175 ft

   WDW-3: Perfs = ~250 ft; h = 175 ft

   As stated in the pressure falloff reports, the neutron density logs were submitted to the OCD with the original permit when the wells were drilled. The logs were resubmitted to the OCD when the wells were re-

permitted as Class I injection wells. The porosity of the formations, 10%, and the reservoir thickness, 175 feet, were determined from these logs.

Thank you for confirming the 175 ft. thick discrepancy with actual perforation thickness. After reviewing OCD UIC Guidance on FOTs, based on the hydrogeology in SE NM and where these wells are located, the actual well perforation thickness is not required and the 175 ft. thickness was derived from logging. This was established before my employment with the OCD.

6) Page 23 #2a: Please change the OCD Permit per well designations to reflect the following: WDW-1 UICI-8; WDW-2 UICI-8-1; and WDW-3 UICI-8-0.

   These changes will be made to the test plan.

The "UICI" permit nomenclature was recently changed to handle the administrative record separately for each permitted well. However, there are instances where reports containing all well information is generally placed in the WDW-1 record.

7) Page 29d&e: Combine the plot to include actual surface and bottom hole pressure readings vs injection rate before, during FOT monitoring.

   These plots will be combined on the FOT reports for WDW-1, WDW-2, and WDW-3.

The historical pressures vs. injection flow rates is very important to keep a record and to identify a well and/or injection interval problem. While the FOT plot of the above is also crucial and surface vs. bottom hole pressure on the same graph provides useful information. Thank you.

8) Page 30 #20: Raw data available to the OCD for a minimum of 3 years. OCD has requested electronic raw data from the 2011 WDW-1, 2 & 3 FOTs, but has not received the data. Please submit the data to the OCD within the next two weeks or by COB Tuesday November 13, 2012.

   NRC will send the raw data to OCD for the 2011 FOT.

I believe the deadline date as passed. Please submit the info. within 2-weeks of receipt of this e-mail. Thank you.

9) Page 31 Section XI: Please remove this section from the FOT Plan, unless NRC wishes to demonstrate injection zone interconnection between wells with bottom hole gauges in all NRC wells (injection and offset) during individual well FOTs.

   Section XI will be removed from the 2012 Test Plan.

Thank you.

Questions:

1) OCD understands why the offset wells are shut-in during each well FOT (only 1 pipeline without bypasses from refinery to all 3 wells; however, the OCD would like to know why bottom hole gauges are not placed in offset wells to prove Section XI is in fact correct? OCD does not concur with Section XI as stated and has provided documentation to NRC on this matter before.

   Section XI will be removed from the 2012 Test Plan. NRC does not have the storage facilities to shut-in the offset wells for the necessary amount of time to perform a pulse interference test in the offset wells to prove Section XI is fact.

Actually, the well can be closed to bypass each well, but you have stated above why a demonstration can't be conducted. Thank you.

2) The P*(false extrapolated P value) vs. P_{1hour} (extrapolated P value after one hour): OCD is not sure what these values represent, but are wondering if these are actual pump pressure value readings associated with the well FOT. Each injection well should be equipped with independent surface and bottom hole pressure gauges to record the actual pressure before, during and after pump shut-off. Reliance on a pump pressure gauge to record surface and/or bottom hole pressure readings is not acceptable to the OCD. Please clarify what these values actually represent and from what specific pressure gauge that the recording is being made?

During the test, a bottomhole pressure gauge is placed in the well to a depth at the top of the injection interval and a surface gauge is installed on the wellhead.

P* (false extrapolated P value) is the shut-in pressure value at infinite time, as derived from the semi-log plot of the pressure falloff test.

P_{1hour} is the shut-in pressure of the well after one hour of shut-in during the pressure falloff test. It is also derived from the semi-log plot of the pressure falloff test.

I recorded the P in the table that I sent you the other day. Perhaps you are correct that there are more injection wells as time progresses and NRC should be aware of new UIC Class II SWD Wells installed in order to protest a new well location during the public notice period. However, the well would need perforated in the same interval, etc....*

Conclusions:

1) NRC already has an OCD approved original FOT Plan (Plan); however, if NRC wishes to update the Plan, OCD requires a resubmittal of the most recent submitted FOT Plan and/or addendum pages addressing the above where applicable in order for the OCD to consider approval of a new Plan.

NRC will submit the FOT Plan with the changes referenced in the responses above.

OCD recommends that NRC consider utilizing the original approved FOTP unless it feels compelled to change it. OCD expects NRC to address any action items where the OCD maintains an original request from its response(s).

From: Chavez, Carl J, EMNRD [mailto:CarlJ.Chavez@state.nm.us]
Sent: Friday, October 26, 2012 1:24 PM
To: Schultz, Michele
Cc: Sanchez, Daniel J., EMNRD; Jones, William V., EMNRD; VonGonten, Glenn, EMNRD; Dade, Randy, EMNRD
Subject: FW: WDW-1, 2 & 3 Fall-Off Test (FOT) Plan

Micki:

OCD has completed its review of the most recently submitted FOT Plan under Navajo Refining Company's (NRC) cover letter dated August 27, 2012.

Observations and/or Comments:

1) OCD recently determined that for the NRC's 3 Class I (NH) Injection Wells that it will stagger the frequency of well FOTs to be performed at least once every 3 years per well in order to allow either 1 well FOT per year or the option to perform 1 well FOT on all 3 wells at least every 3 years.
2) Page 3 Section III: Only one OCD approved Fall-Off Test Plan (FOTP) is required and OCD currently acknowledges the original FOTP as the official version in place to date.
3) Page 10 #4b: NRC appears to be decreasing the injection rate to minimize the total volume of injection fluid required to complete a well FOT and possibly to demonstrate a minimum pressure differential in the injection zone of 100 psig is achieved during any given FOT.

   There is a calculation along with historical FOT flow rate and volume information for NRC to estimate the minimum volume of injection fluid needed at each well location to achieve a pseudo steady-state injection rate and achieve a radial flow condition before pump shut-off and FOT monitoring. NRC and OCD should be working to determine the actual injection zone capacity and not attempting to engineer FOTs to achieve minimum pressure differential criteria. However, any other reason for minimizing the total volume of injected fluid is not valid.

Requirements:

1) Page 11 #7: Bottom hole gauges shall be emplaced and monitored in offset wells during well FOTs if NRC wishes to prove Section XI is true. Otherwise, please remove Section XI. OCD discussions with subsurface well experts indicates that due to the spatial distance and hydrogeological variability between NRC wells and site-specific injection zones, installation of bottom hole pressure gauges would likely not prove interconnection between NRC wells.
2) Page 12 #10: WDWs were recently stimulated with acid in coiled tubing. Please confirm that a C-103 Sundry Notice was submitted to the OCD for approval in advance of the well work.
3) Page 13 #15: FOTs shall not be designed to achieve the minimum 100 psig pressure differential. The FOT should demonstrate the actual maximum pressure differential from pressure buildup through injection into the injection zone. The FOT should demonstrate the actual injection zone ability to receive injected fluids.
4) Page 20 #5: Same as No. 3 above.
5) Page 22 #4: The "h" injection interval value used for each well during the FOT shall be based on the footage of the perforated injection interval(s) per well. If NRC disagrees, could you please provide the h values and basis for using a different "h" value per well for FOT calculations.
6) Page 23 #2a: Please change the OCD Permit per well designations to reflect the following: WDW-1 UICI-8; WDW-2 UICI-8-1; and WDW-3 UICI-8-0.
7) Page 29d&e: Combine the plot to include actual surface and bottom hole pressure readings vs injection rate before, during FOT monitoring.
8) Page 30 #20: Raw data available to the OCD for a minimum of 3 years. OCD has requested electronic raw data from the 2011 WDW-1, 2 & 3 FOTs, but has not received the data. Please submit the data to the OCD within the next two weeks or by COB Tuesday November 13, 2012.
9) Page 31 Section XI: Please remove this section from the FOT Plan, unless NRC wishes to demonstrate injection zone interconnection between wells with bottom hole gauges in all NRC wells (injection and offset) during individual well FOTs.

Questions:

1) OCD understands why the offset wells are shut-in during each well FOT (only 1 pipeline without bypasses from refinery to all 3 wells; however, the OCD would like to know why bottom hole gauges are not placed in offset wells to prove Section XI is in fact correct? OCD does not concur with Section XI as stated and has provided documentation to NRC on this matter before.
2) The P*(false extrapolated P value) vs. P_{1hour} (extrapolated P value after one hour): OCD is not sure what these values represent, but are wondering if these are actual pump pressure value readings associated with the well FOT. Each injection well should be equipped with independent surface and bottom hole pressure gauges to record the actual pressure before, during and after pump shut-off. Reliance on a pump pressure gauge to record surface and/or bottom hole pressure readings is not acceptable to the OCD. Please clarify what these values actually represent and from what specific pressure gauge that the recording is being made?

Conclusions:

1) NRC already has an OCD approved original FOT Plan (Plan); however, if NRC wishes to update the Plan, OCD requires a resubmittal of the most recent submitted FOT Plan and/or addendum pages addressing the above where applicable in order for the OCD to consider approval of a new Plan.

Please contact me if you have questions. Thank you.

Carl J. Chavez, CHMM
New Mexico Energy, Minerals & Natural Resources Department

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http://www.emnrd.state.nm.us/ocd/environmental.htm#environmental

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From: Chavez, Carl J, EMNRD
Sent: Thursday, October 25, 2012 11:05 AM
To: Schultz, Michele (Michele.Schultz@hollyfrontier.com)
Subject: WDW-1, 2 & 3 Fall-Off Test (FOT) Plan

Micki:

I'm currently reviewing the FOT Plan under your cover letter dated August 27, 2012.

I happened to notice on Page 3 Section III "Developing a Test Plan" that a Test Plan must be developed annually. This is not correct. Once Navajo Refining Company LLC (NRC) has an approved Test Plan (which it does), it must follow it for future FOTs.

The FOT Plan may be revised if approved by the OCD.

Consequently, the OCD will review the FOT Plan. I am curious as to how this FOT Plan differs from the original approved version? The OCD has recently determined that for NRC's Class I (NH) Injection Wells that it will stagger the frequency of FOTs for each its 3 wells to be performed at least once every 3 years per well in order to allow one per year to be tested. I presume that NRC has the option to perform 1 FOT every 3 years on its 3 wells too if that works.....? FOT Plan that I am reviewing depicts annual FOTs at each well location..... Also, Mr. Holder recently informed me that NRC will conduct FOTs on all 3 wells this year to assess their current condition and is referenced in the FOT Plan.....

Please contact me if you have questions. Thank you.

Carl J. Chavez, CHMM
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Table VII contains a listing of all wells within the one mile area of review of WDW-1, WDW-2, and WDW-3. Figure 33 is a Midland Map Company base map of the area containing the one mile area of review. Tables VII through XIV contain a list all wells within the one mile area of review of WDW-1, WDW-2, and WDW-3 that have had modifications to the current permit or have had new drilling and/or completion permits issued since the 2003 discharge application submittal. Please refer to the "Discharge Application 2003" submittal and to the OCD online well files for additional information.

9.0 CONCLUSIONS

All testing was successful and met the OCD and EPA requirements. Holly Corporation, Inc. fulfills all analysis and reporting requirements of the USEPA's "Pressure Falloff Testing Guideline, Third Revision", issued by Region 6, dated August 8, 2002, with the submittal of this report. Pressure falloff and bottom-hole pressure testing were conducted according to these guidelines.

APPENDIX A

CHRONOLOGY OF FIELD ACTIVITIES

APPENDIX A

NAVAJO REFINING COMPANY
CHRONOLOGY OF FIELD ACTIVITIES
WDW-1, WDW-2, AND WDW-3
"MEWBOURNE", CHUKKA", AND "GAINES"

MONDAY, MARCH 31, 2008

Traveled to Artesia, New Mexico, contacted the client, and contacted contractors. Navajo started injecting into well No. 3 at a rate of 250 gpm at 10:00 a.m. MST. Well No. 3 will be shut in until 10:00 a.m. tomorrow April 1, 2008.

TUESDAY, APRIL 1, 2008

Subsurface arrived at the jobsite at 6:30 a.m. MST and Pro Well Testing & Wireline (Pro Well) arrived at the jobsite at 7:00 a.m. MST. Pro Well had the down hole pressure gauge on bottom in well No. 3 at 9:14 a.m. MST and the well was shutin at 10:03 a.m. MST. Pro Well moved over to well No. 2. At 10:05 a.m. MST Navajo control room had well No. 1 at constant injection rate of 263 bpm. Pro Well had the pressure gauge on bottom at 10:30 a.m. MST in well No. 2 and moved over to well No. 1. When Pro Well started to remove the pressure gauge from the wellhead on well No. 1, the gauge blew out of the top fitting releasing fluid into the air. The 2-inch crown ball valve did not hold and was washed out, the needle valve on the gauge was locked down and would not close, and the 1/2-inch fitting on the wellhead was washed out.

Well No. 1 had to be shut in and flow diverted to well No. 2. Well No. 2 was brought to a constant rate of 268 gpm at 12:08 a.m. MST. Pro Well placed the bottom-hole pressure gauge on bottom in well No. 1 at 5:40 a.m. MST. Pro Well had to hot shot out a crossover and repair an o-ring before setting the bottom-hole gauge in well No. 1. According to the schedule well No. 1 and well No. 2 will be exchanged and well No. 2 will go ahead of well No. 1. In well No. 1 the bottom of the well was tagged at 8856 ft.

In well No. 2, the bottom of the well was tagged at 7928 ft, and in well No. 3 the bottom could not be tagged there because there was not enough wire on the reel to tag bottom. Pro Well only had 8000 feet on the reel. The bottom-hole gauge in well No. 1 was placed at 7924 ft, in well No. 2 the bottom-hole gauge was placed at 7570 ft, and in well No. 3 the bottom-hole gauge was placed at 7660 ft. Subsurface left the jobsite at 6:00 a.m. MST.

WEDNESDAY, APRIL 2, 2008

Subsurface arrived on the jobsite at 7:30 a.m. MST and checked wells. No leaks were present. Spoke with Navajo Champion contract hand responsible for the well. Subsurface informed the contract hand to be back at the well site at 11:45 a.m. and well No. 2 would be shut in. Well No. 1 was opened and flow diverted from well No.2 at 12:00 p.m. MST and well No. 2 was shut in at 12:09 p.m. MST. The plant could not keep well No.3 shut in due to a buildup of fluids in the holding tanks at the plant. The control room requested that another well be opened.

At 1:04 p.m. MST well No. 3 was opened and injection started at 280 gpm. At 1:20 p.m. MST flow was stabilized in well No. 1 and well No. 3 at 235 gpm and 230 gpm, respectively. At 3:11 p.m. MST well No. 1 was flowing 235 gpm at 900 psig and well No. 3 was flowing at 230 gpm at 570 psig. Well No. 2 was shut in with no leaks. Between 12:00 p.m. MST and 1:00 p.m. MST the filters in the primary filter pod were changed twice. Between 1:00 p.m. MST and 3:00 p.m. MST the filters in the primary filter pod were again changed twice. The supervisor for the Champion crew informed me that when the holding tanks at the plant are full, they have to change the filters frequently due to solids being sent down the pipe line.

THURSDAY, APRIL 3, 2008

Subsurface arrived at the jobsite at 9:00 a.m. MST and checked all three wells. Well No. 3 was injecting at a rate of 232 gpm with a wellhead pressure of 565 psig. Well No. 2 was shut in with on leaks and a wellhead pressure of 95 psig. Well No. 1 was injecting at a rate of 235 gpm with a wellhead pressure of 900 psig. At 1:42 p.m. MST well No. 2 was opened at a rate of 145 gpm with a wellhead pressure of 650 psig. The plant needed two operational wells to handle the fluids. At 1:50 p.m. MST well No. 1 was shut in with 550 psig on the wellhead. At 2:35 p.m. MST well No. 2 had to be shut in to change filters (no secondary bypass on well No. 2). At 3:05 p.m. MST well No. 2 had a stable rate of 158 gpm with a wellhead pressure of 650 psig.

FRIDAY, APRIL 4, 2008

Subsurface arrived at the jobsite at 10:30 a.m. MST. Pro Well arrived at well No. 3 at 11:20 a.m. MST. Pro Well pulled all gauges from the wellbores making 5 minute gradient stops every 1000 ft. Well No. 3 was shut in for 45 minutes before pulling pressure memory gauge out of the wellbore. Well No. 2 was shut in for 55 minutes before pulling pressure memory gauges out of the wellbore. On well No. 3, the wellhead pressure remained constant at 48 psig. On well No. 2 at 7570 feet wellhead pressure was 240 psig, at 7000 feet wellhead pressure was 119 psig, at 6000 feet wellhead pressure was 119 psig, at 5000 feet wellhead pressure was 114 psig, at 4000 feet wellhead pressure was 110 psig, at 3000 feet wellhead pressure was 110 psig, at 2000 feet wellhead pressure was 110 psig, at 1000 feet wellhead pressure was 108 psig, and at surface wellhead pressure was 106 psig. On well No. 1, the wellhead pressure was relative constant at 60 psig. All wells were turned over to Navajo Refining at 7:40 p.m. MST.

APPENDIX K

WELL BUILD UP/FALLOFF TEST PLAN

APPENDIX K
WELL BUILD-UP/FALL-OFF TEST PLAN
NAVAJO REFINERY
ARTESIA, NM
MEWBOURNE WELL NO. 1
CHUKKA WELL NO. 2
GAINES WELL NO 3

General Test Operational Consideration

The fall-off testing for all three wells was performed concurrently starting with Gaines Well No. 3, then moving to Mewbourne Well #1, completing the process with Chukka Well No. 2. A constant rate was maintained in the first targeted well for 24 hours prior to prior to shut-in with one offset well shut-in and the other offset under a constant injection rate. Tandem memory bottom hole memory gauges were lowered into each well (two memory gauges per well) and allowed to stabilize for one hour. The targeted well was shut-in for 24 hours with the two offset wells maintaining a constant injection rate. This sequence was repeated for each well. At the end of the fall-off test, on the last well in the sequence, the bottom hole pressure gauges were pulled from each well making gradient stops every 1000 feet. The above sequence is necessary for the refinery to remain operational. The refinery generates a fluid volume that requires a minimum of two operational wells during a 24 hour cycle.

The injection build-up period will consist no less than 24 hours at a constant rate and the pressure fall-off was maintained for no less than 24 hours. The 24 hour build-up/fall-off periods were established when the wells were completed and is backed by historical data from Mewbourne Well No. 1 and Chukka Well No. 2. All three wells inject into the Wolfcamp/Cisco formations. Due to refinery expansion, the refinery does not have the storage capacity to shut-in more than two wells for 24 hours and will have to maintain a constant injection into the two offset wells while performing a fall-off in the adjacent well. Historically prior to the completion of Gaines Well No. 3 one well was shut-in while the offset well injected a constant rate and this method produced measurable results.

The memory gauges that were used are sapphire gauges that will have an accuracy of 0.025% full scale (FS) or 0.01% of the reading and will have a resolution of 0.0003% (FS). The pressure range of the gauges will be from 0 – 10,000 psi. These are typical bottom hole memory gauges with the best accuracy available in the area. The gauges were lowered to the top of the injection interval at 7924 feet in Mewbourne Well No. 1, 7820 feet in Chukka Well No. 2, and 7660 feet in Gaines Well No. 3. The recoding period was set to record pressures at a minimum of every 10 seconds. The specifications of the gauges that used are listed in Attachment 1.

The fluid that was used for the injection test was the refinery's brine waste water (effluent). A current waste analysis of the fluid is included in the final report. A summary of the brine waste water is in Table 5.

A crown valve has been installed on all three wells. The lubricator was installed into the crown valve before running into the wellbore with the memory gauges. The well was shut-in through two inline gate valves. The first valve is located in the injection line just prior to the wellhead and the other is located behind the filter pods. The instantaneous shut-in of the well was accomplished by the mechanical operated valve (MOV) behind the filter pods.

Background Information

All background information will be included in the final report encompassing a log of the events (Chronology of Field Activity), a over view of the Geology, a current area of review (AOR) update, fall-off analysis including pervious injection data (rate and volume history), gauge calibration certificates, bottom hole pressure analysis, well schematic, electric logs, reservoir fluid description, and injection fluid analysis. The procedure to do the fall-off will also be included in the final report. If necessary an AOR update will be included prior to the build-up/fall-off testing to ascertain the offset injection wells current condition. Historically there has not been any production or injection in the current injection interval within a one mile radius of Mewborune Well No. 1, Chukka Well No. 2, or Gaines Well No. 3 and it does not appear necessary at this point in time to perform a pre-job AOR.

Navajo Refining has been running annual fall-off test on Mewborune Well No. 1, Chukka Well No. 2 since 2000 using sapphire gauges. The tests have followed EPA guidelines and have been performed to comply with OCD directives for UIC non-hazardous Class I injection wells. In April of 2006 build-up/fall-off test was conducted on Mewborne Well No. 1 & Chukka Well No. 2. The 24 hour build-up portion of the testing was done at a constant injection rate of 250 gallons per minute. The fall-off portion of the testing was terminated after 24 hours. The Mewbourne Well No. 1 had a permeability of 3,090 md (height of 175 ft, reservoir viscosity 0.72 cp) for a radius of investigation of 4,087 ft and a skin of 92.7. The Chukka Well No. 2 had a permeability of 2,912 md (height of 175 ft, reservoir viscosity 0.72 cp) for a radius of investigation of 3,689 ft and a skin of 81.5. Table 6 is a summary of the pressure fall-off results from 2000 to 2006 using the refinery's brine waste stream.

Figures 1 though 3 are the well schematics for Mewborune Well No. 1, Chukka Well No. 2, or Gaines Well No. 3. Table 3 is a summary of the injection intervals for each well. Table 4 is a summary of the injection fluid analysis. Table 5 is a summary of the formation fluids. The majority of the background information can also be found in the permit application that was submitted to the State of New Mexico Oil Conservation Division for each well.

Conducting the Fall-off Testing

This is the procedure that was proposed to perform the fall-off test for the wells at Navajo Refining facility. The following procedure was modified at the job site due to a washed out crown valve on Mewbourne Well No. 1. Instead of performing the second fall-off sequence on Mewbourne Well No. 1 the second well in the sequence was switched and Chukka Well No. 2, which became the second well in the sequence. The Mewbourne Well No. 1 had to be shut-in to replace the crown valve and a new 24 hour build-up injection period was commenced on Mewbourne Well No. 1.

Monday, March 31, 2008

- At 7:00 AM Navajo begin constant rate injection into the Gaines Well (#3) at 250 gpm with refinery effluent (waste water).
- Shut in the Chukka Well (#2).
- Use the Mewbourne Well (#1) to inject excess waste water not going to the Gaines Well at the required rate.

Tuesday, April 1, 2008

- At 7:00 AM Pro Well Testing & Wireline will rig up slick line units on all three wells. A gauge ring will be run into the wells and the bottom of fill tagged. Pull out of the hole with the gauge ring and run tandem memory tools into each well. The memory tools will be set at 7924-feet in Well No. 1, 7820-feet in Well No. 2, and 7660-feet in Well No. 3.
- Allow the pressure gauges to stabilize for approximately one hour, after setting the memory tools in place, shut in the Gaines Well No. 3, following ±24 hours of stabilized injection.
- Leave the Chukka Well No. 2 shut in.
- Start a constant injection rate at 250 gpm into the Mewbourne Well No. 1 to begin the ±24-hour injection period with waste water.

Wednesday, April 2, 2008

- End the 24 hour pressure fall-off test in the Gaines Well No 3, if possible leave well shut in.
- Shut in the Mewbourne Well No. 1 following ±24 hours of stabile injection, for the fall testing.
- Start injection into the Chukka Well No. 2 at 250 gpm to begin the ±24-hour stable injection period with waste water.

Thursday, April 3, 2008

- End the pressure fall-off test in the Mewbourne Well No. 1 after ±24 hours.
- Shut in the Chukka Well No 2 following ±24 hours of stabile injection, for fall-off testing.
- Leave the Gaines Well shut in and begin injection into the Mewbourne Well No 1 at the required rate to dispose of excessive waste water.

Friday, April 4, 2008

- End the pressure fall-off test in the Chukka Well No 2 after ±24 hours.

- At the end of the day, stop injection into all wells and pull the tandem memory tools out of each well and conduct gradient surveys at 1000-foot intervals.
- Rig down the slick line units and return the wells to operations.

Evaluation of the Test Results

The fall-off analysis will be completed by a qualified engineer using PAN System analysis program and reviewed for accuracy by a licensed professional engineer (PE). The fall-off analysis will include the following;

- A log-log plot with a derivative diagnostic plot used to identify flow regimes.
- A wellbore storage portion and infinite acting portion of the plot.
- A semi-log plot with wellbore storage, P*, and slope.
- An expanded portion of the semi-log plot showing the infinite acting pressure portion (radial flow).
- The height of the injection interval used for the calculations will be included analysis section based on historical data.
- The viscosity of the formation used for the calculations will be included analysis section based on historical data.
- A summary of all the equations used for the analysis.
- An explanation of any temperature or pressure anomalous.

The injection records one year prior to the testing will be included in the analysis.

The following tables (Table 1 and Table 2) summarize the build-up/fall-off test Schedule and Procedure, and Well Data. Included are directions to the Gaines Well 3 well site. Table 3 is a summary of the local geology for injection intervals.

Schedule and Procedure Table 1

Date	Mewbourne Well No. 1	Chukka Well No. 2	Gaines Well No. 3
Monday, March 31, 2008	Inject into well at the desired rate.	Shut-in well.	Inject into the well at a **constant rate** for 24 hours at 250 gpm.
Tuesday, April 1, 2008	1. Run bottom hole gauges into the well and tag bottom with ring gauge, set pressure gauge at 7924'; 2. Start injecting into the well at a **constant rate** for 24 hours at 250 gpm.	1. Run bottom hole gauges into the well and tag bottom with ring gauge, set pressure gauge at 7820'; 2. Leave well shut-in.	1. Run bottom hole gauges into the well and tag bottom with ring gauge, set pressure gauge at 7660'; 2. Shut-in for 24 hour fall-off testing.
Wednesday, April 2, 2008	Shut-in for 24 hour fall-off testing.	Start injecting at a **constant rate** for 24 hours.	If possible, leave well shut-in.
Thursday, April 3, 2008	Leave well shut-in to the end of the 24 hour test period.	Shut-in well for 24 hours fall-off testing.	Inject into well at the desired rate.
Friday, April 4, 2008	1. Inject into well at the desired rate; 2. At the end of the day, stop injection, pull gauges from the well taking gradient stops ever 1000 ft. 3. Turn well over to refinery.	1. Leave well shut-in; 2. At the end of the day pull gauges from the well taking gradient stops ever 1000 ft. 3. Turn well over to refinery.	1. Stop injection into the well; 2. At the end of the day pull gauges from the well taking gradient stops ever 1000 ft. 3. Turn well over to refinery.

Well Data Table 2

	Mewbourne Well No. 1	Chukka Well No. 2	Gaines Well No. 3
Tubing	4.5", 11.6 lb/ft, N-80, SMLS, R3, LT&C 7879'	3.5", 9.2 lb/ft, J-55, NUE 10RD 7528'	4.5", 11.6 lb/ft, J-55, LT&C, 8RD 7575'
Packer	7"x 3.5", EVI Oil Tools (Arrow), X-1, ID 3", 7879'	5.5"x 2.875" Weatherford (Arrow), X-1, ID 2.4375", 7528'	7"x 2.875" Kenco Tools (Arrow), X-1, ID 2.4375" 7575'
Perforations	Upper: 7924 – 42, 7974 – 8030, 8050 – 56, 8066 – 80, 8118 – 27, 8132 – 40, 8160 – 64, 8170 – 88 Lower: 8220 - 54, 8260 - 70, 8280 - 8302, 8360 - 66, 8370 - 78, 8400 - 10, 8419 - 23, 8430 - 46, 8460 - 64, 8470 - 76	Upper: 7570 – 7620, 7676 – 7736 Lower: 7826 - 34, 7858 - 80, 7886 - 7904, 7916 - 36, 7944 - 64, 7990 - 8042, 8096 - 8116, 8191 - 8201, 8304 - 19, 8395 - 99	Upper: 7660 – 8450 Lower: 8540 - 8620
Protection Casing	7", 29 lb/ft, N-80, LT&C, 9094 - 7031	5.5", 17 lb/ft, L-80, LT&C	7", 29 lb/ft, N-80, LT&C
Cement Top Protection Casing	Surface	Surface	900'
PBTD / TD	9004' / 10,200'	8770' / 10,372'	9022' / 10,119'
Formation	Wolfcamp / Cisco / Canyon	Wolfcamp / Cisco / Canyon	Wolfcamp / Cisco / Canyon
Inj. Interval	7450' – 9016'	7270' – 8894'	7303' – 8894'

Geology Information Table 3

Injection Zone Formation	Mewbourn Well No. 1 (KB height = 3693 feet)		Chukka Well No. 2 (KB height = 3623 feet)		Gaines Well No. 3 (KB height = 3625 feet)	
	Measured Depth below KB (feet)	Subsea Depth (feet)	Measured Depth below KB (feet)	Subsea Depth (feet)	Measured Depth below KB (feet)	Subsea Depth (feet)
Lower Wolfcamp	7450	-3757	7270	-3647	7303	-3678
Cisco	7816	-4123	7645	-4022	7650	-4025
Canyon	8475	-4782	8390	-4767	8390	-4765
Base of Injection Zone (base of Canyon)	9016	-5323	8894	-5271	8894	-5269

Injected Brine Waste Water Table 4

Chemical Date	Refinery Waste Water Jan 22, 1998	Refinery Waste Water June 14, 1999
Calcium (mg/L)	48	21
Magnesium (mg/L)	98	31
Potassium (mg/L)	51	18
Sodium (mg/L)	1200	424
Chloride (mg/L)	1100	630
Fluoride (mg/L)	3.9	74
Nitrate-N (mg/L)	<0.01	<10
Sulfate (mg/L)	1500	570
Alkalinity (CaCO3) (mg/L)	100	40
pH (s.u.)	6.0 – 9.0	6.0 – 9.0
Specific Gravity (g/L)	1.00 – 1.01	1.00 – 1.01

Formation Fluids Table 5

Chemical	Mewbourn Well No. 1	Chukka Well No. 2	Gaines Well No. 3	Average
Date	July 31, 1998	June 14, 1999	Nov 8, 2006	
Fluoride (mg/l)	2.6	9.7	Not Detected	6.15
Chloride (mg/L)	19,000	15,000	10,447	14,815.67
NO3-N (mg/L)	<10	<10	--	<10
SO4 (mg/L)	2,200	2000	1,908	2,036
CaCO3 (mg/L)	1000	1210	--	1105
Specific Gravity (g/L)	1.034	1.0249	--	1.0295
TDS (mg/L)	33,000	20,000	--	26,500
Specific Conductance (uMHOs/cm)	52,000	43,000	--	47,500
Potassium (mg/L)	213	235	85.5	177.83
Magnesium (mg/L)	143	128	155	142
Calcium (mg/L)	390	609	393	464
Sodium (mg/L)	12,770	8,074	6,080	8,974.67
pH (s.u.)	8.1	7.2	--	7.65

Summary of Pressure Fall-off Test Results Table 6

Test No.	Test Date	P_{static} (psia)	kh/μ (md-ft/cp)	V_{well} (10^6 gal)	V_{total} (10^6 gal)
WDW-1					
1	07/31/98	2913.7	537,308	0.0	0.0
2	04/19/00	3073.7	479,925	95.4	108.6
3	12/18/00	3202.9	413,013	196.5	240.3
4	01/14/01	3207.8	405,663	204.7	253.2
5	05/17/01	3243.6	357,754	247.9	303.7
6	08/30/01	3254.8	354,579	276.4	349.5
7	02/14/02	3332.9	398,234	333.1	424.3
8	03/26/03	3370.33	452,416	466.6	631.7
9	08/26/03	3380.97	484,330	506.6	702.5
10	04/05/06	3422.45	751,105	842.4	1208.9
WDW-2					
1	06/05/99	2973.0	1,527,413	0.0	0.0
2	01/13/01	3207.7	713,248	48.7	253.0
3	02/02/01	3213.6	713,575	50.8	262.5
4	05/18/01	3243.6	712,844	56.3	304.4
5	08/29/01	3258.7	572,135	73.4	349.3
6	02/15/02	3311.7	874,047	91.5	424.3
7	03/22/03	3342.48	854,309	165.1	631.7
8	08/27/03	3349.14	837,073	195.9	702.5
9	04/06/06	3395.12	707,786	366.5	1208.9