Inland
PRODUCTION COMPANY
A Subsidiary of Inland Resources Inc.

February 27, 2004

State of Utah
Division of Oil, Gas & Mining
Attn: Diana Whitney
1594 West North Temple - Suite 1210
P.O. Box 145801
Salt Lake City, Utah 84114-5801

RE: Applications for Permit to Drill: Blackjack Federal 1-5-9-17, 7-5-9-17, 8-5-9-17, and 10-5-9-17.

Dear Diana:

Enclosed find APD's on the above referenced wells. The 8-5-9-17 and 10-5-9-17 are Exception Locations. I have notified Patsy Barreau in our Denver Office and she will be sending the appropriate paperwork. If you have any questions, feel free to give either Brad or myself a call.

Sincerely,

Mandie Crozier

Mandie Crozier
Regulatory Specialist

mc
enclosures

RECEIVED
MAR 0 1 2004
DIV. OF OIL, GAS & MINING

001

Form 3160-3
(September 2001)

FORM APPROVED
OMB No. 1004-0136
Expires January 31, 2004

UNITED STATES
DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

APPLICATION FOR PERMIT TO DRILL OR REENTER

5. Lease Serial No. UTU-74808

6. If Indian, Allottee or Tribe Name N/A

1a. Type of Work: ☒ DRILL ☐ REENTER

7. If Unit or CA Agreement, Name and No. Blackjack

1b. Type of Well: ☒ Oil Well ☐ Gas Well ☐ Other ☒ Single Zone ☐ Multiple Zone

8. Lease Name and Well No. Blackjack Federal 10-5-9-17

2. Name of Operator
Inland Production Company

9. API Well No. 43-013-32553

3a. Address Route #3 Box 3630, Myton UT 84052

3b. Phone No. *(include area code)* (435) 646-3721

10. Field and Pool, or Exploratory Monument Butte

4. Location of Well *(Report location clearly and in accordance with any State requirements.*)*
At surface NW/SE 1676' FSL 1982' FEL 4434365Y 40.05735
At proposed prod. zone 582955X -110.02739

11. Sec., T., R., M., or Blk. and Survey or Area
NW/SE Sec. 5, T9S R17E

14. Distance in miles and direction from nearest town or post office*
Approximatley 13.5 miles southeast of Myton, Utah

12. County or Parish Duchesne

13. State UT

15. Distance from proposed* location to nearest property or lease line, ft. (Also to nearest drig. unit line, if any) Approx. 356' f/lse, 356' f/unit

16. No. of Acres in lease 232.46

17. Spacing Unit dedicated to this well 40 Acres

18. Distance from proposed location* to nearest well, drilling, completed, applied for, on this lease, ft. Approx. 1925'

19. Proposed Depth 6500'

20. BLM/BIA Bond No. on file #4488944

21. Elevations (Show whether DF, KDB, RT, GL, etc.) 5251' GL

22. Approximate date work will start* 3rd Quarter 2004

23. Estimated duration Approximately seven (7) days from spud to rig release.

24. Attachments

The following, completed in accordance with the requirements of Onshore Oil and Gas Order No.1, shall be attached to this form:

1. Well plat certified by a registered surveyor.
2. A Drilling Plan.
3. A Surface Use Plan (if the location is on National Forest System Lands, the SUPO shall be filed with the appropriate Forest Service Office).
4. Bond to cover the operations unless covered by an existing bond on file (see Item 20 above).
5. Operator certification.
6. Such other site specific information and/or plans as may be required by the authorized officer.

25. Signature Mandie Crozier | Name *(Printed/Typed)* Mandie Crozier | Date 2/27/04

Title Regulatory Specialist

Federal Approval of this Action is Necessary

Approved by *(Signature)* | Name *(Printed/Typed)* BRADLEY G. HILL | Date 03-03-04

Title | Office ENVIRONMENTAL SCIENTIST III

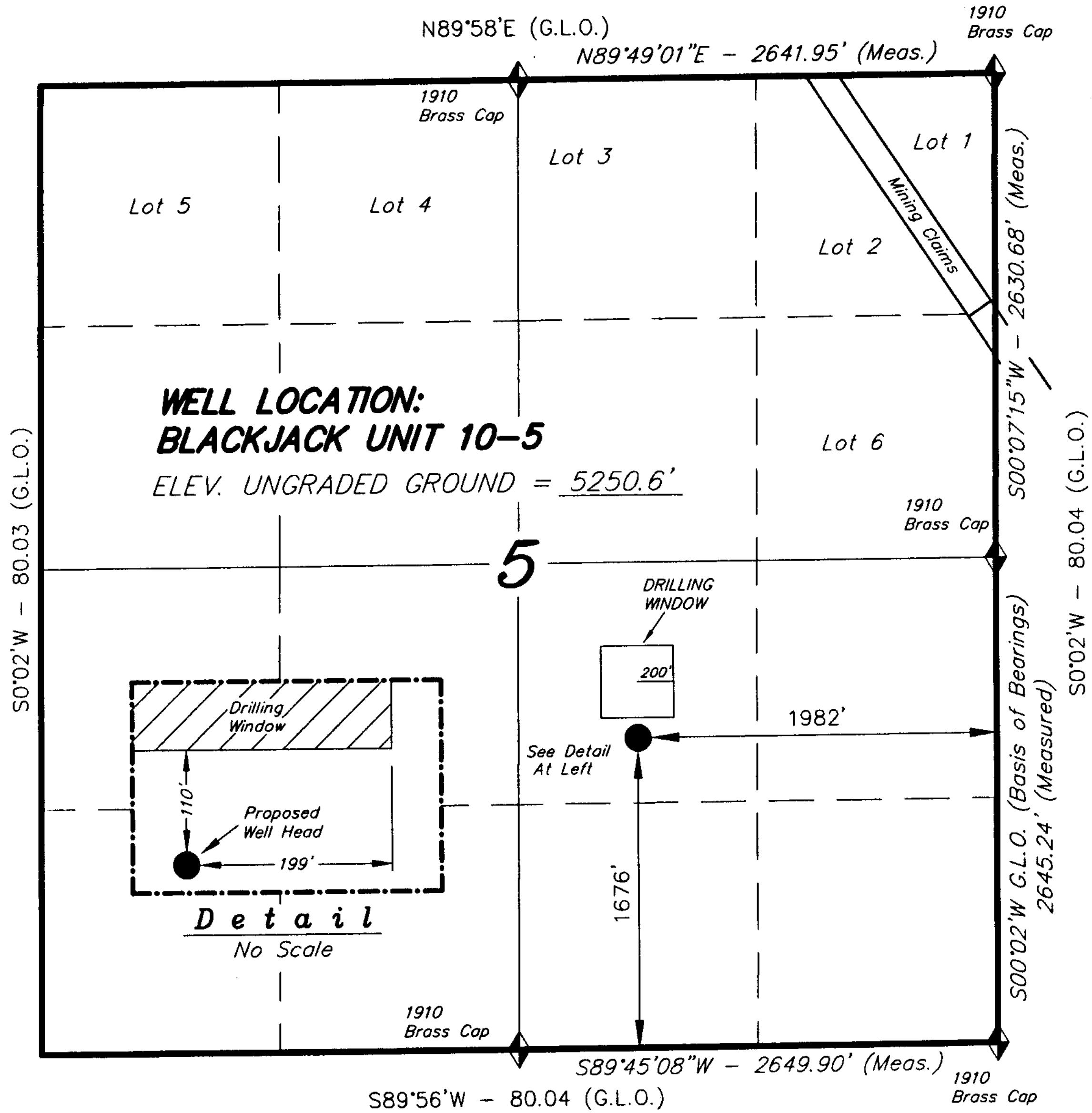
Application approval does not warrant or certify the the applicant holds legal or equitable title to those rights in the subject lease which would entitle the applicant to conduct operations thereon.
Conditions of approval, if any, are attached.

Title 18 U.S.C. Section 1001 and Title 43 U.S.C. Section 1212, make it a crime for any person knowingly and willfully to make to any department or agency of the United States any false, fictitious or fraudulent statements or representations as to any matter within its jurisdiction.

*(Instructions on reverse)

RECEIVED
MAR 0 1 2004
DIV. OF OIL, GAS & MINING

T9S, R17E, S.L.B.&M.



◆ = SECTION CORNERS LOCATED

BASIS OF ELEV; U.S.G.S. 7–1/2 min QUAD (MYTON SE)

INLAND PRODUCTION COMPANY

WELL LOCATION, BLACKJACK UNIT 10–5, LOCATED AS SHOWN IN THE NW 1/4 SE 1/4 OF SECTION 5, T9S, R17E, S.L.B.&M. DUCHESNE COUNTY, UTAH.

THIS IS TO CERTIFY THAT THE ABOVE PLAT WAS PREPARED FROM FIELD NOTES OF ACTUAL SURVEYS MADE BY ME OR UNDER MY SUPERVISION AND THAT THE SAME ARE TRUE AND CORRECT TO THE BEST OF MY KNOWLEDGE AND BELIEF.

REGISTERED LAND SURVEYOR
No.189377
STACY W. STEWART
STATE OF UTAH

REGISTERED LAND SURVEYOR
REGISTRATION No. 189377
STATE OF UTAH

TRI STATE LAND SURVEYING & CONSULTING
180 NORTH VERNAL AVE. – VERNAL, UTAH 84078
(435) 781–2501

SCALE: 1" = 1000'	SURVEYED BY: D.J.S.
DATE: 12–31–03	DRAWN BY: J.R.S.
NOTES:	Red Hills Drafting, Inc.

002

United States Department of the Interior

BUREAU OF LAND MANAGEMENT
Utah State Office
P.O. Box 45155
Salt Lake City, Utah 84145-0155

IN REPLY REFER TO:
3160
(UT-922)

March 2, 2004

Memorandum

To: Assistant District Manager Minerals, Vernal District

From: Michael Coulthard, Petroleum Engineer

Subject: 2003 Plan of Development Black Jack Unit, Duchesne County, Utah.

Pursuant to email between Diana Whitney, Division of Oil, Gas and Mining, and Mickey Coulthard, Utah State Office, Bureau of Land Management, the following wells are planned for calendar year 2003 within the Black Jack Unit, Duchesne County, Utah.

API #	WELL NAME	LOCATION
(Proposed PZ Green River)		
43-013-30720	Allen Fed 43-5R-9-17	Sec 5 T09S R17E 2350 FSL 0731 FEL
(Re-entry)		
43-013-32552	Blackjack Fed 8-5-9-17	Sec 5 T09S R17E 1757 FNL 0638 FEL
43-013-32553	Blackjack Fed 10-5-9-17	Sec 5 T09S R17E 1676 FSL 1982 FEL
43-013-32554	Blackjack Fed 7-5-9-17	Sec 5 T09S R17E 1801 FNL 1895 FEL
43-013-32555	Blackjack Fed 1-5-9-17	Sec 5 T09S R17E 0841 FNL 0668 FEL

This office has no objection to permitting the wells at this time.

/s/ Michael L. Coulthard

bcc: File - Black Jack Unit
Division of Oil Gas and Mining
Agr. Sec. Chron
Fluid Chron

MCoulthard:mc:3-2-04

INLAND PRODUCTION COMPANY
BLACKJACK FEDERAL #10-5-9-17
NW/SE SECTION 5, T9S, R17E
DUCHESNE COUNTY, UTAH

ONSHORE ORDER NO. 1

DRILLING PROGRAM

1. ***GEOLOGIC SURFACE FORMATION:***

Uinta formation of Upper Eocene Age

2. ***ESTIMATED TOPS OF IMPORTANT GEOLOGIC MARKERS:***

Uinta	0' – 1640'
Green River	1640'
Wasatch	6025'

3. ***ESTIMATED DEPTHS OF ANTICIPATED WATER, OIL, GAS OR MINERALS:***

Green River Formation 1640' – 6500' - Oil

4. ***PROPOSED CASING PROGRAM***

Please refer to the Monument Butte Field Standard Operation Procedure (SOP).

5. ***MINIMUM SPECIFICATIONS FOR PRESSURE CONTROL:***

Please refer to the Monument Butte Field SOP. See Exhibit "C".

6. ***TYPE AND CHARACTERISTICS OF THE PROPOSED CIRCULATION MUDS:***

Please refer to the Monument Butte Field SOP.

7. ***AUXILIARY SAFETY EQUIPMENT TO BE USED:***

Please refer to the Monument Butte Field SOP.

8. ***TESTING, LOGGING AND CORING PROGRAMS:***

Please refer to the Monument Butte Field SOP.

9. ***ANTICIPATED ABNORMAL PRESSURE OR TEMPERATURE:***

The anticipated maximum bottom hole pressure is 2000 psi. It is not anticipated that abnormal temperatures will be encountered.

10. ***ANTICIPATED STARTING DATE AND DURATION OF THE OPERATIONS:***

Please refer to the Monument Butte Field SOP.

INLAND PRODUCTION COMPANY
BLACKJACK FEDERAL #10-5-9-17
NW/SE SECTION 5, T9S, R17E
DUCHESNE COUNTY, UTAH

ONSHORE ORDER NO. 1

MULTI-POINT SURFACE USE & OPERATIONS PLAN

1. ***EXISTING ROADS***

See attached Topographic Map "A"

To reach Inland Production Company well location site Blackjack Federal #10-5-9-17 located in the NW 1/4 SE 1/4 Section 5, T9S, R17E, Duchesne County, Utah:

Proceed southwesterly out of Myton, Utah along Highway 40 - 1.6 miles ± to the junction of this highway and UT State Hwy 53; proceed southeasterly along Hwy 53 – 10.9 miles ± to it's junction with an existing road to the southwest; proceed southwesterly – 1.0 miles ± to it's junction with the beginning of the proposed access road; proceed northeasterly along the proposed access road 1,430' ± to the proposed well location.

2. ***PLANNED ACCESS ROAD***

See Topographic Map "B" for the location of the proposed access road.

3. ***LOCATION OF EXISTING WELLS***

Refer to Exhibit "B".

4. ***LOCATION OF EXISTING AND/OR PROPOSED FACILITIES***

Please refer to the Monument Butte Field Standard Operating Procedure (SOP).

5. ***LOCATION AND TYPE OF WATER SUPPLY***

Please refer to the Monument Butte Field SOP. See Exhibit "A".

6. ***SOURCE OF CONSTRUCTION MATERIALS***

Please refer to the Monument Butte Field SOP.

7. ***METHODS FOR HANDLING WASTE DISPOSAL***

Please refer to the Monument Butte Field SOP.

8. ***ANCILLARY FACILITIES***

Please refer to the Monument Butte Field SOP.

9. ***WELL SITE LAYOUT***

See attached Location Layout Diagram.

10. ***PLANS FOR RESTORATION OF SURFACE***

Please refer to the Monument Butte Field SOP.

11. ***SURFACE OWNERSHIP*** - Bureau Of Land Management

12. ***OTHER ADDITIONAL INFORMATION***

The Archaeological Resource Survey and Paleontological Resource Survey for this area are attached. Archaeological Report #1028-01, 2/23/98. Paleontological Resource Survey prepared by, Uintah Paleo, 3/19/98. See attached report cover pages, Exhibit "D".

For the Blackjack Federal #10-5-9-17 Inland Production Company requests a 475' ROW in Least U-020252 and a 185' ROW in Lease UTU-72108 to allow for construction of the proposed access road as well as the gas lines. **Refer to Topographic Map "B" and Topographic Map "C".** For a ROW plan of development, please refer to the Monument Butte Field SOP.

Inland Production Company requests a 50' ROW for the Blackjack Federal #10-5-9-17 to allow for construction of a 6" gas gathering line, and a 3" poly fuel gas line. Both lines will tie in to the existing pipeline infrastructure. **Refer to Topographic Map "C."** For a ROW plan of development, please refer to the Monument Butte Field SOP.

Water Disposal
Please refer to the Monument Butte Field SOP.

Reserve Pit Liner
A felt pad and 12 mil liner may be used at he operators own discresion. Please refer to the Monument Butte Field SOP.

Location and Reserve Pit Reclamation
Please refer to the Monument Butte Field SOP.

The following seed mixture will be used on the topsoil stockpile, to the recontoured surface of the reserve pit, and for final reclamation: (All poundages are in pure live seed)

Gardners Saltbush	*Atriplex Gardneri*	4 lbs/acre
Green Molly Summer Cyress	*Kochia American*	4 lbs/acre
Galleta Grass	*Hilaria Jamesii*	4 lbs/acre

Details of the On-Site Inspection

The proposed Federal #10-5-9-17 was on-sited on 8/20/03. The following were present; Brad Mecham (Inland Production), Byron Tolman (Bureau of Land Management), and SWCA representatives. Weather conditions were clear.

13. ***LESSEE'S OR OPERATORS REPRESENTATIVE AND CERTIFICATION***

Representative

Name: Brad Mecham

Address: Route #3 Box 3630
Myton, UT 84052

Telephone: (435) 646-3721

Certification

Please be advised that INLAND PRODUCTION COMPANY is considered to be the operator of well #10-5-9-17 NW/SE Section 5, Township 9S, Range 17E: Lease UTU-74808 Duchesne County, Utah: and is responsible under the terms and conditions of the lease for the operations conducted upon the leased lands. Bond coverage is provided by Hartford Accident #4488944.

I hereby certify that the proposed drillsite and access route have been inspected, and I am familiar with the conditions which currently exist; that the statements made in this plan are true and correct to the best of my knowledge; and that the work associated with the operations proposed here will be performed by Inland Production Company and its contractors and subcontractors in conformity with this plan and the terms and conditions under which it is approved. This statement is subject to the provisions of 18 U.S.C. 1001 for the filing of a false statement.

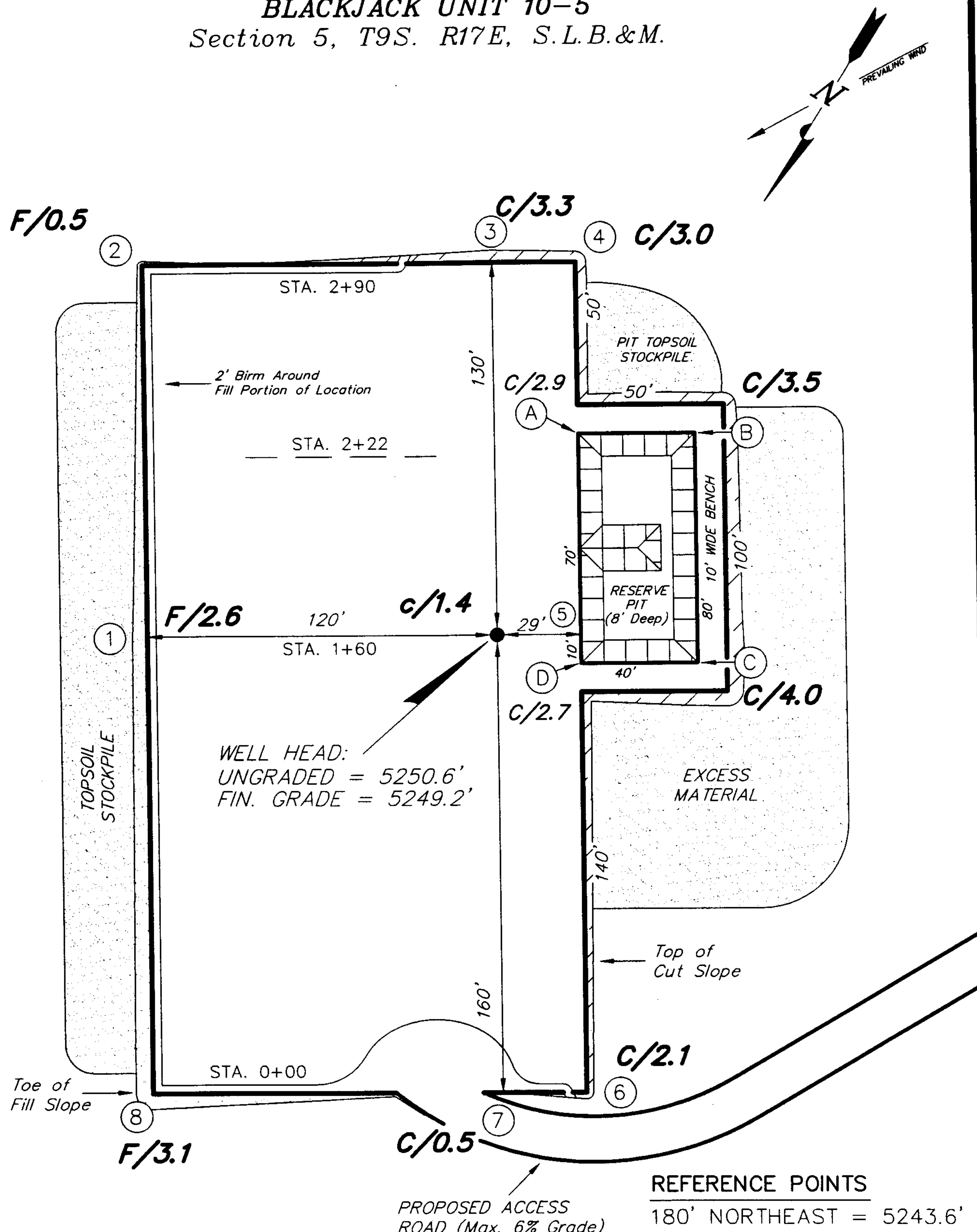
2/27/04
Date

Mandie Crozier
Mandie Crozier
Regulatory Specialist

INLAND PRODUCTION COMPANY

BLACKJACK UNIT 10-5

Section 5, T9S. R17E, S.L.B.&M.



REFERENCE POINTS

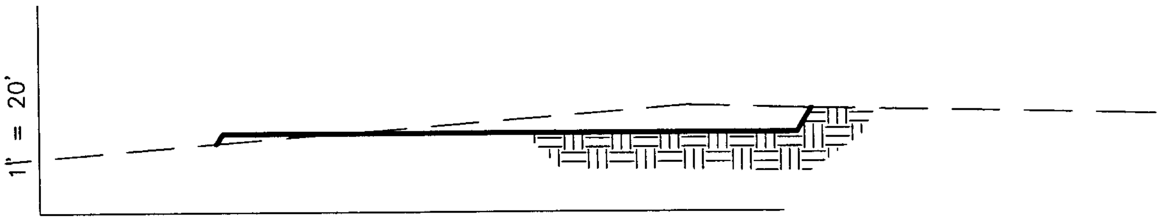
180' NORTHEAST = 5243.6'
230' NORTHEAST = 5239.2'
210' NORTHWEST = 5249.3'
260' NORTHWEST = 5248.2'

SURVEYED BY: D.J.S.	SCALE: 1" = 50'	Tri State Land Surveying, Inc. (435) 781-2501
DRAWN BY: J.R.S. Red Hills Drafting, Inc.	DATE: 12-31-03	180 NORTH VERNAL AVE. VERNAL, UTAH 84078

INLAND PRODUCTION COMPANY

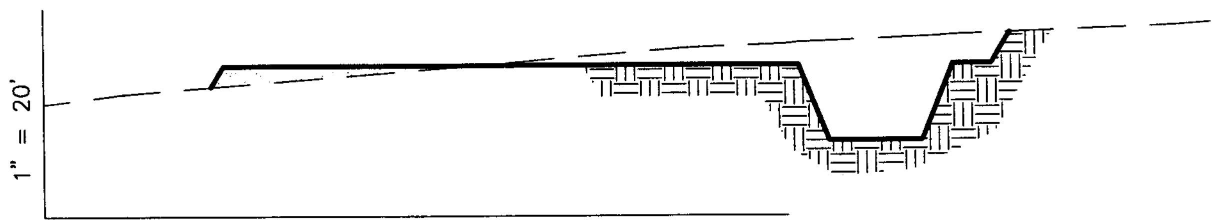
CROSS SECTIONS

BLACKJACK UNIT 10-5



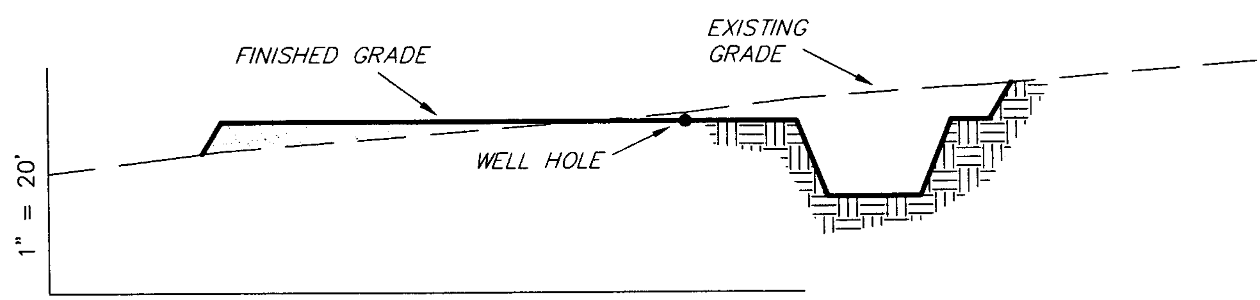
1" = 50'

STA. 2+90



1" = 50'

STA. 2+22



1" = 50'

STA. 1+60

1" = 50'

STA. 0+00

NOTE:
UNLESS OTHERWISE NOTED
ALL CUT/FILL SLOPES ARE
AT 1.5:1

ESTIMATED EARTHWORK QUANTITIES
(No Shrink or swell adjustments have been used)
(Expressed in Cubic Yards)

ITEM	CUT	FILL	6" TOPSOIL	EXCESS
PAD	1,430	1,430	Topsoil is not included in Pad Cut	0
PIT	640	0		640
TOTALS	2,070	1,430	890	640

SURVEYED BY:	D.J.S.	SCALE:	1" = 50'
DRAWN BY:	J.R.S.	DATE:	12-31-03

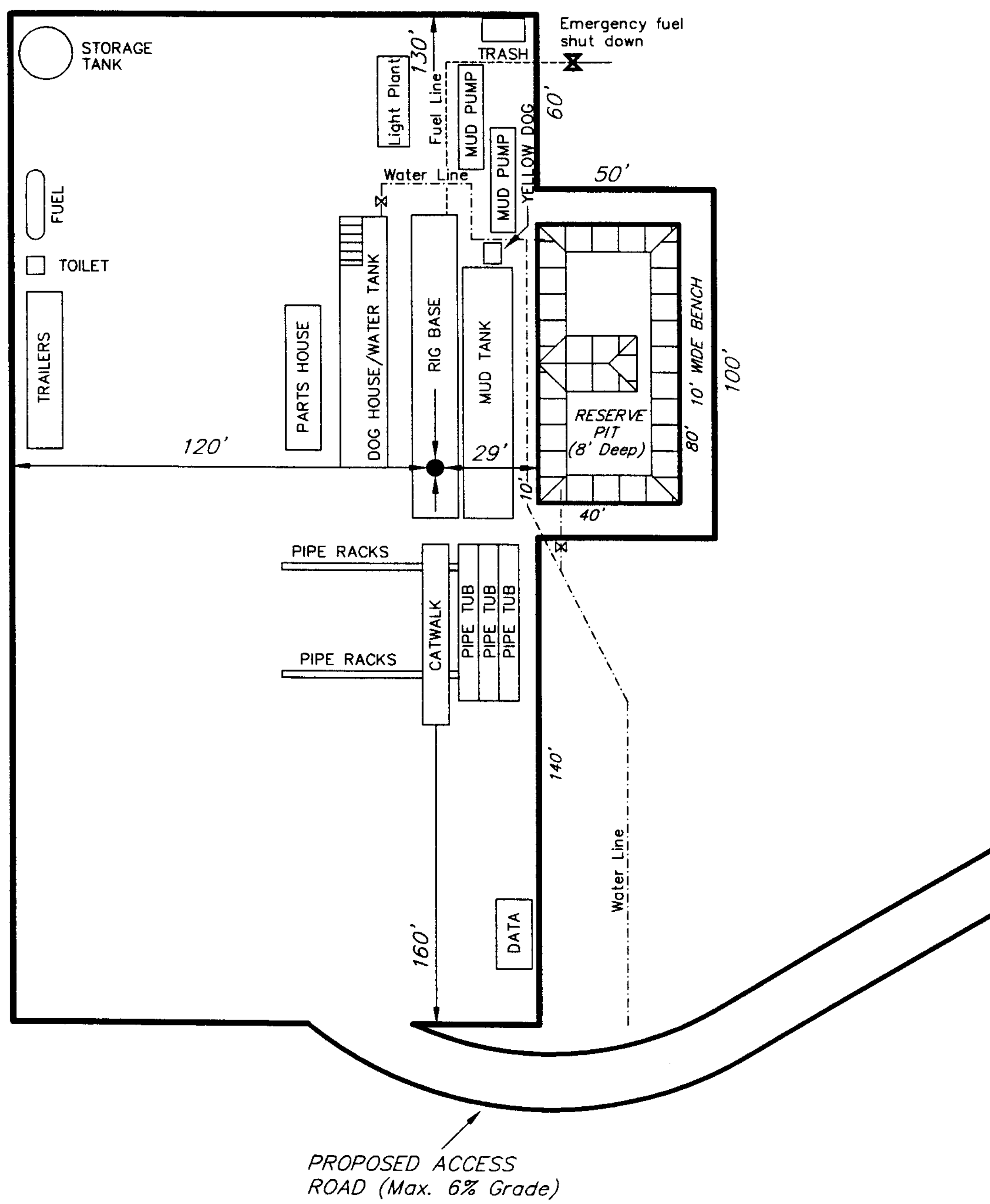
Red Hills Drafting, Inc.

Tri State Land Surveying, Inc.
(435) 781-2501
180 NORTH VERNAL AVE. VERNAL, UTAH 84078

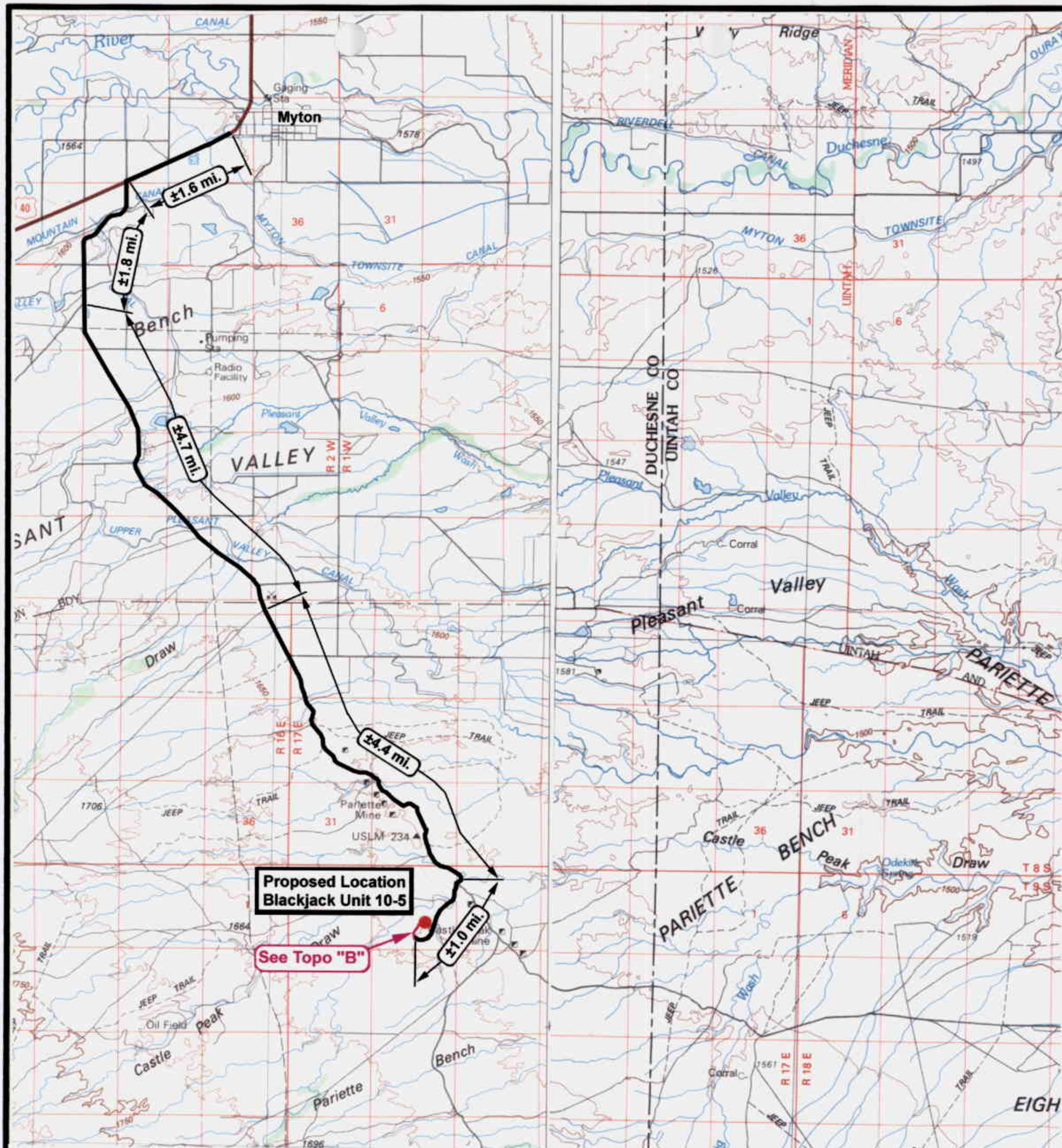
INLAND PRODUCTION COMPANY

TYPICAL RIG LAYOUT

BLACKJACK UNIT 10-5



SURVEYED BY: D.J.S.	SCALE: 1" = 50'	Tri State Land Surveying, Inc. (435) 781-2501
DRAWN BY: J.R.S. Red Hills Drafting, Inc.	DATE: 12-31-03	180 NORTH VERNAL AVE. VERNAL, UTAH 84078



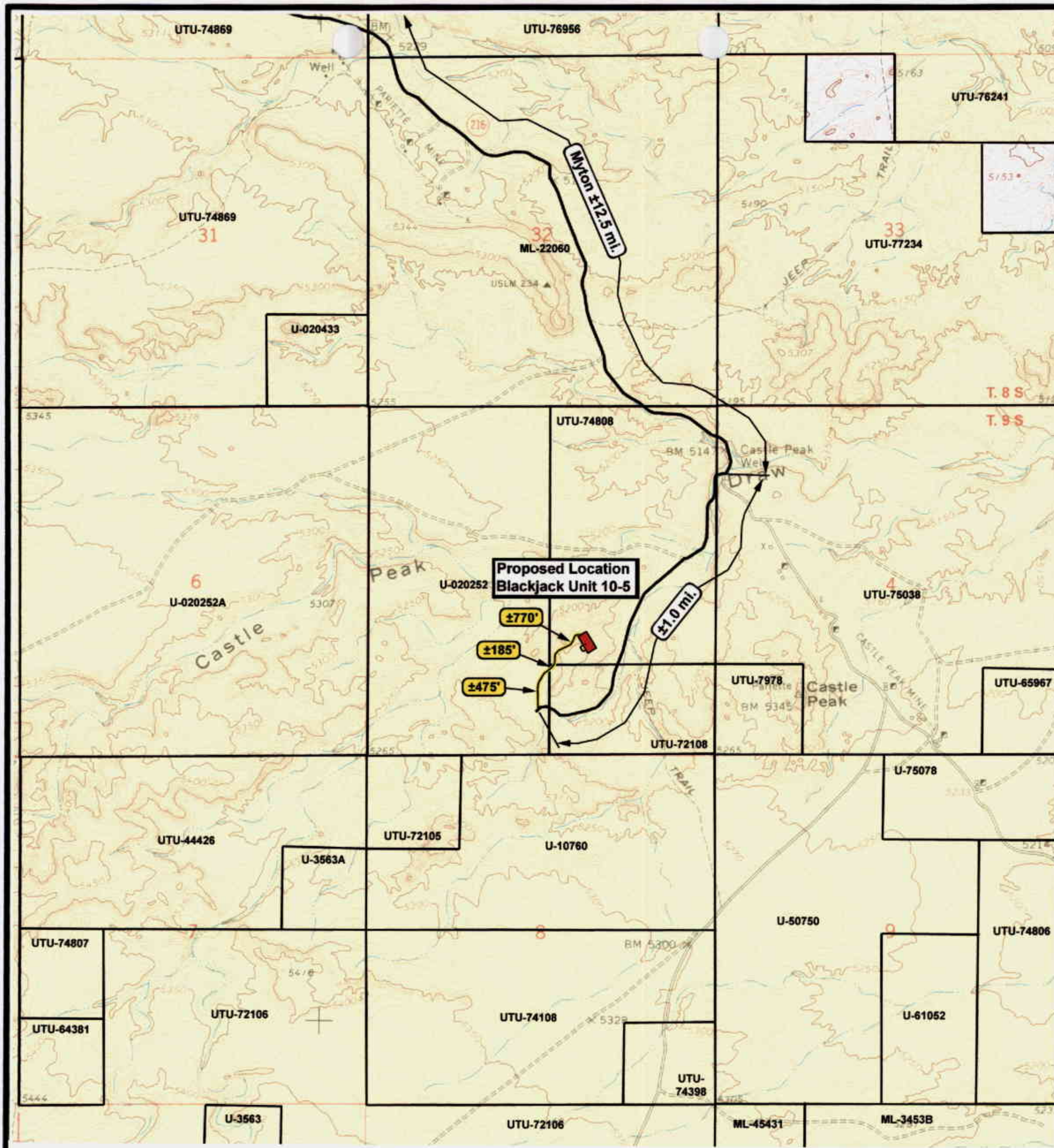
Inland RESOURCES INC.

Tri-State Land Surveying Inc.
(435) 781-2501
180 North Vernal Ave. Vernal, Utah 84078

Blackjack Unit 10-5
SEC. 5, T9S, R17E, S.L.B.&M.

SCALE: 1 = 100,000
DRAWN BY: R.A.B.
DATE: 01-22-2004

TOPOGRAPHIC MAP "A"



Inland RESOURCES INC.

Blackjack Unit 10-5
SEC. 5, T9S, R17E, S.L.B.&M.

N

Tri-State Land Surveying Inc.
(435) 781-2501
180 North Vernal Ave. Vernal, Utah 84078

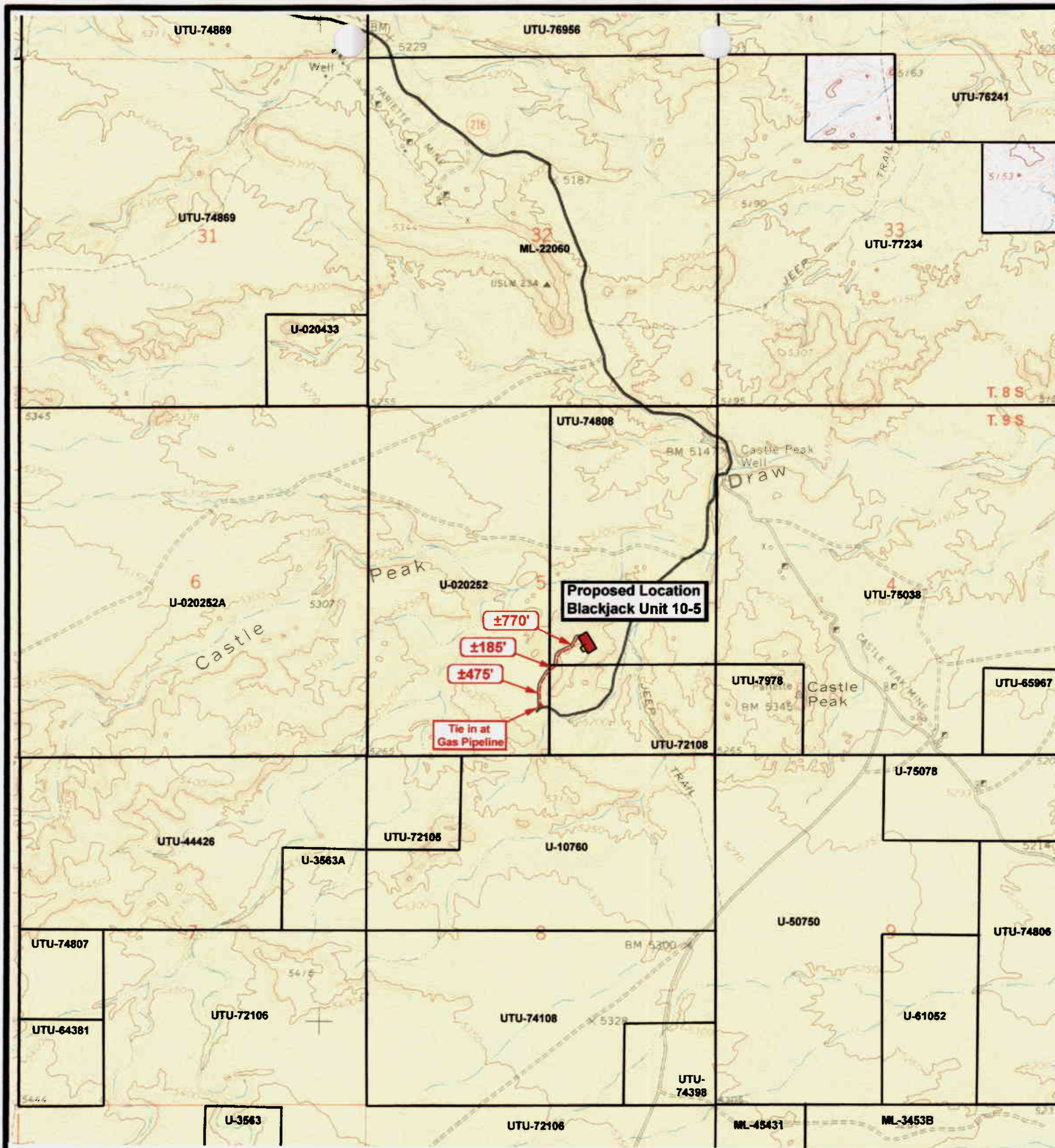
Legend

Existing Road

Proposed Access

SCALE: 1" = 2,000'
DRAWN BY: R.A.B.
DATE: 01-22-2004

TOPOGRAPHIC MAP
"B"



Inland
RESOURCES INC.

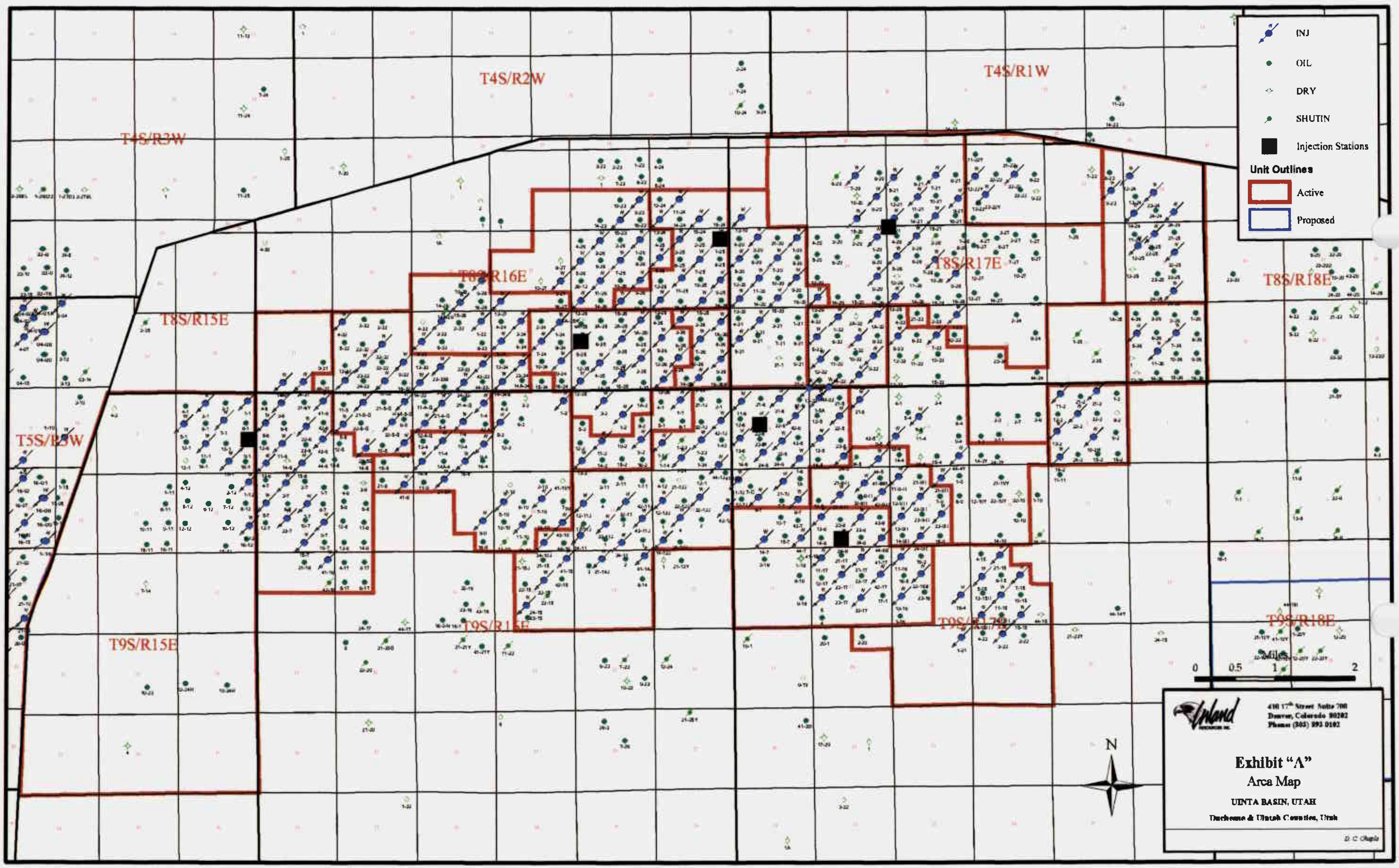
N

Tri-State
Land Surveying Inc.
(435) 781-2501
180 North Vernal Ave. Vernal, Utah 84078

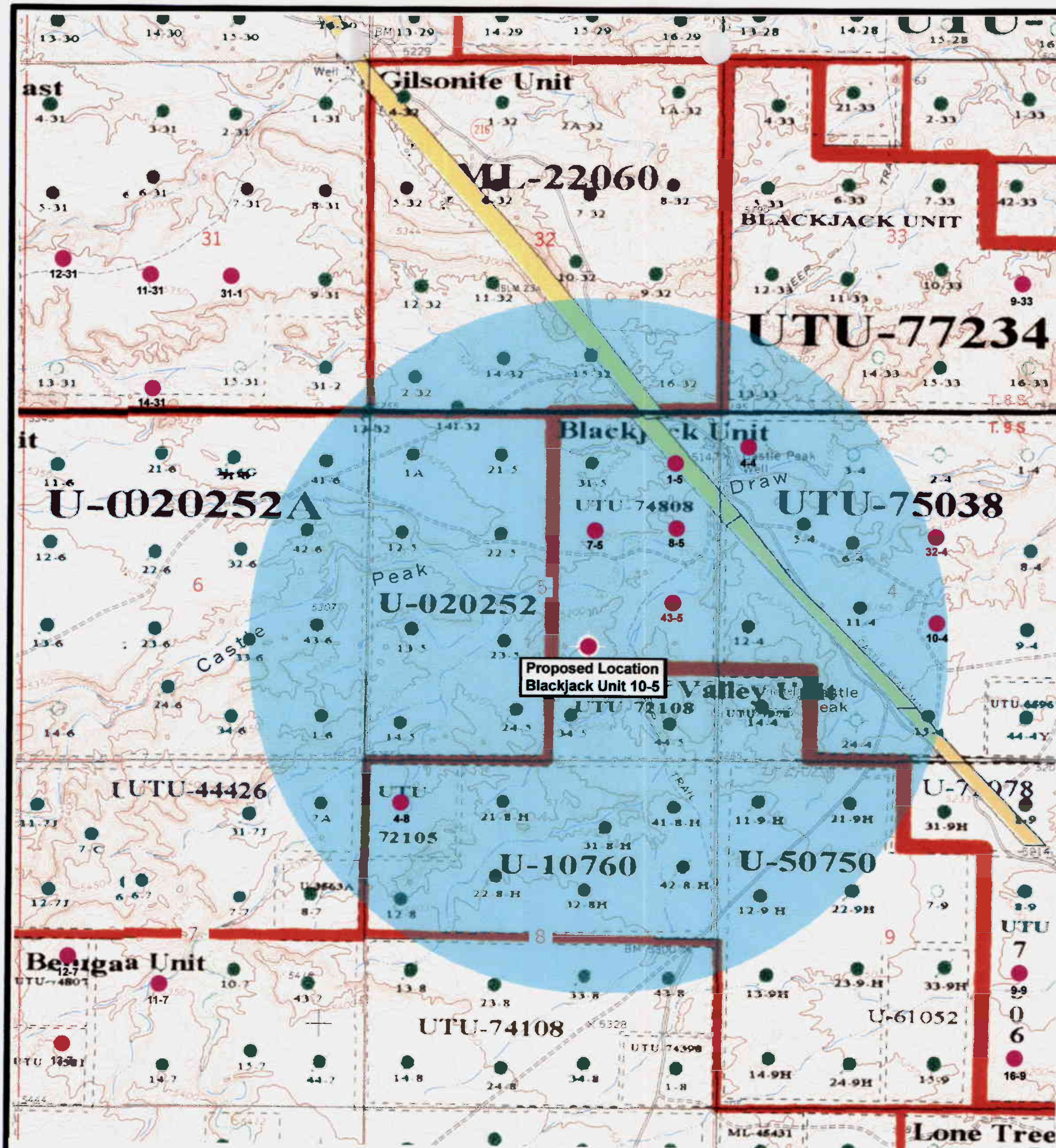
Blackjack Unit 10-5
SEC. 5, T9S, R17E, S.L.B.&M.

SCALE: 1" = 2,000'
DRAWN BY: R.A.B.
DATE: 01-22-2004

TOPOGRAPHIC MAP
"C"



January 15, 2003



Inland RESOURCES INC.

Blackjack Unit 10-5
SEC. 5, T9S, R17E, S.L.B.&M.

N

Tri-State Land Surveying Inc.
(435) 781-2501
180 North Vernal Ave. Vernal, Utah 84078

SCALE:	1" = 2,000'
DRAWN BY:	R.A.B.
DATE:	01-22-2004

Legend

- Well Locations
- One-Mile Radius

Exhibit "B"

2-M SYSTEM

Blowout Prevention Equipment Systems

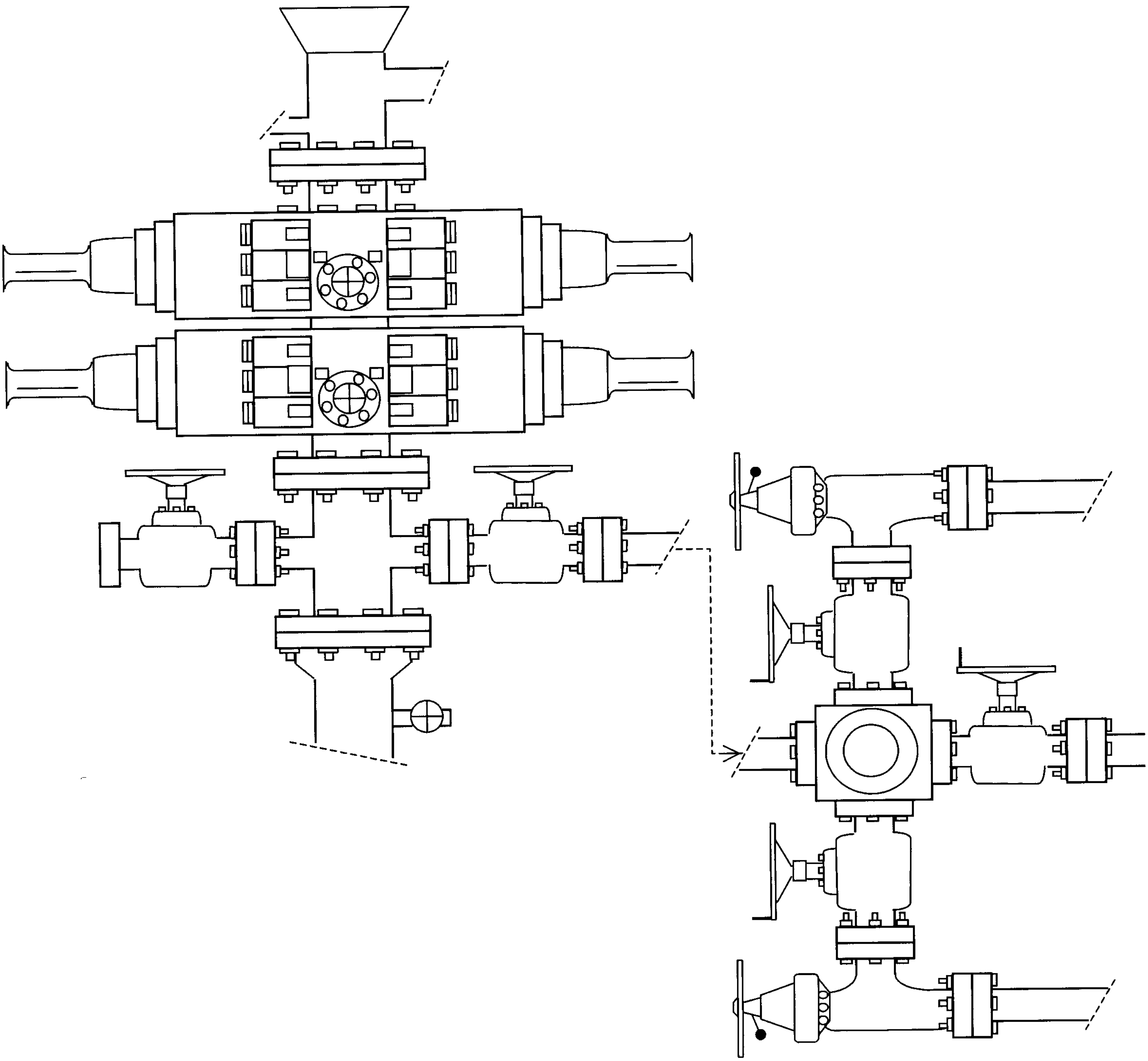


EXHIBIT C

1028-01

Exhibit "D"
Page 1 of 2

Castle Draw
P. Valley

A CULTURAL RESOURCE SURVEY OF THE BLACK JACK UNIT, DUCHESNE COUNTY, UTAH

by

Sarah Cowie, Danielle Diamond, and Heather Weymouth

Prepared for:

Inland Production Company
P.O. Box 790233
Vernal, Utah 84079-0233

Prepared by:

Sagebrush Consultants, L.L.C.
3670 Quincy Avenue, Suite 203
Ogden, Utah 84403

Under Authority of Cultural Resources Use Permit No. 97-UT-54630

and

Utah State Antiquities Permit No. U-98-SJ-0072b,p

Archaeological Report No. 1028-01

February 23, 1998

PALEONTOLOGICAL FIELD SURVEY REPORT

INLAND PRODUCTION COMPANY

BLACKJACK UNIT

SECTIONS 3, 4, 5, 9, AND 10

TOWNSHIP 9 SOUTH, RANGE 17 EAST

DUCHESNE COUNTY, UTAH

March 19, 1998

Uinta #98-3

UINTA PALEO

BY

SUE ANN BILBEY, Ph.D.
GEOLOGIST AND PALEONTOLOGIST
UINTA PALEONTOLOGICAL ASSOCIATES
446 SOUTH 100 WEST
VERNAL, UTAH 84078
801-789-1033

004

WORKSHEET
APPLICATION FOR PERMIT TO DRILL

APD RECEIVED: 03/01/2004

API NO. ASSIGNED: 43-013-32553

WELL NAME: BLACKJACK FED 10-5-9-17

OPERATOR: INLAND PRODUCTION (N5160)

CONTACT: MANDIE CROZIER

PHONE NUMBER: 435-646-3721

PROPOSED LOCATION:

NWSE 05 090S 170E

SURFACE: 1676 FSL 1982 FEL

BOTTOM: 1676 FSL 1982 FEL

DUCHESNE

MONUMENT BUTTE (105)

INSPECT LOCATN BY: / /

Tech Review	Initials	Date
Engineering		
Geology		
Surface		

LEASE TYPE: 1 - Federal

LEASE NUMBER: UTU-74808

SURFACE OWNER: 1 - Federal

PROPOSED FORMATION: GRRV

COALBED METHANE WELL? NO

LATITUDE: 40.05735

LONGITUDE: 110.02739

RECEIVED AND/OR REVIEWED:

✓ Plat

✓ Bond: Fed[1] Ind[] Sta[] Fee[]
(No. 4488944)

N Potash (Y/N)

N Oil Shale 190-5 (B) or 190-3 or 190-13

✓ Water Permit
(No. MUNICIPAL)

N RDCC Review (Y/N)
(Date:)

NA Fee Surf Agreement (Y/N)

LOCATION AND SITING:

___ R649-2-3.

Unit BLACKJACK (GR)

___ R649-3-2. General
Siting: 460 From Qtr/Qtr & 920' Between Wells

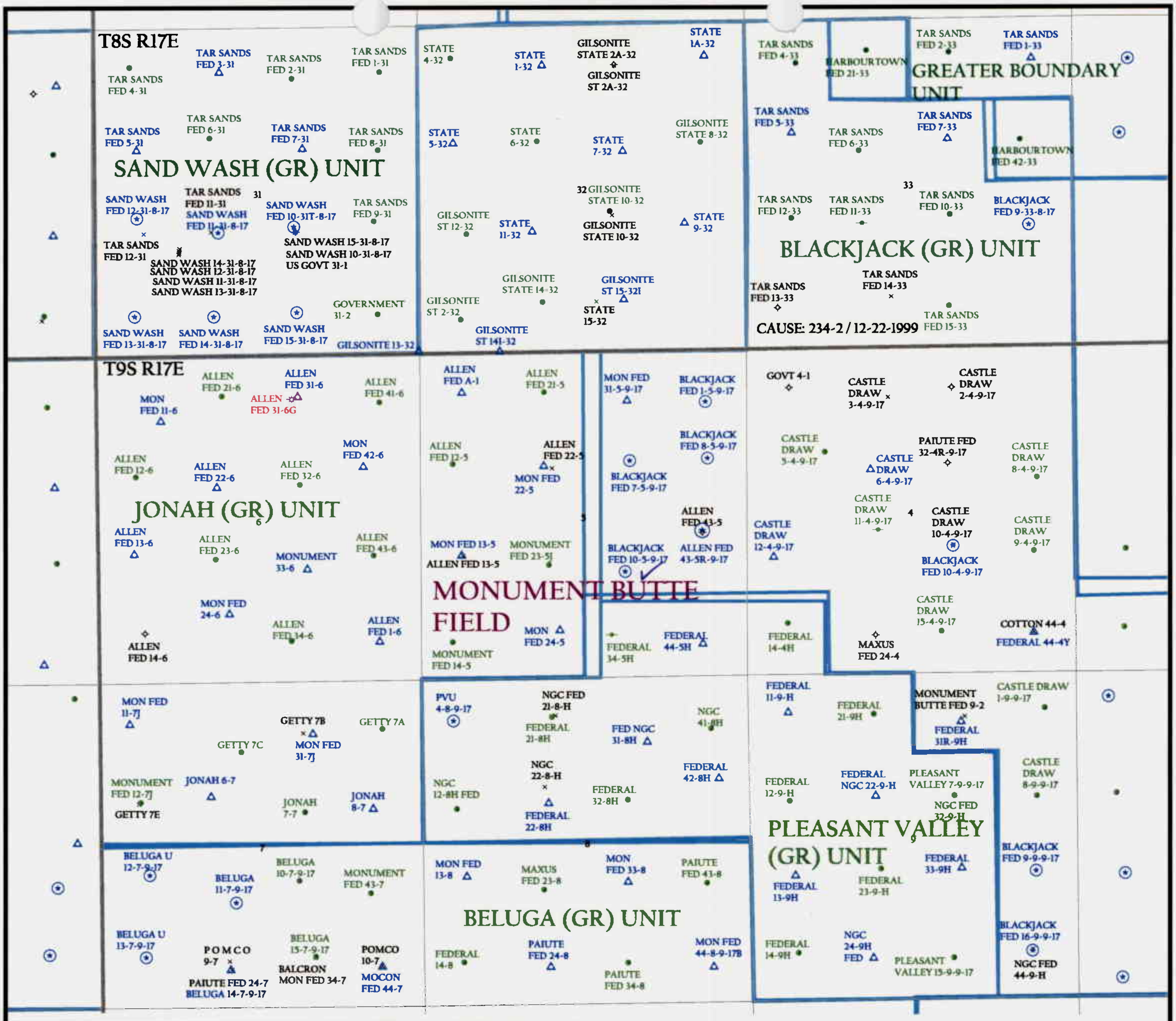
___ R649-3-3. Exception

✓ Drilling Unit
Board Cause No: 234-2
Eff Date: 12-22-1999
Siting: Suspends General Siting

___ R649-3-11. Directional Drill

COMMENTS: Sop, Separate file

STIPULATIONS: 1-Federal approval



OPERATOR: INLAND PROD CO (N5160)

SEC. 5 T.9S, R.17E

FIELD: MONUMENT BUTTES (105)

COUNTY: DUCHESNE

CAUSE: 234-2 / 12-22-1999

Utah Oil Gas and Mining

Wells
- GAS INJECTION
- GAS STORAGE
- LOCATION ABANDONED
- NEW LOCATION
- PLUGGED & ABANDONED
- PRODUCING GAS
- PRODUCING OIL
- SHUT-IN GAS
- SHUT-IN OIL
- TEMP. ABANDONED
- TEST WELL
- WATER INJECTION
- WATER SUPPLY
- WATER DISPOSAL

Unit Status
- EXPLORATORY
- GAS STORAGE
- NF PP OIL
- NF SECONDARY
- PENDING
- PI OIL
- PP GAS
- PP GEOTHERML
- PP OIL
- SECONDARY
- TERMINATED

Field Status
- ABANDONED
- ACTIVE
- COMBINED
- INACTIVE
- PROPOSED
- STORAGE
- TERMINATED

N
W
E
S

PREPARED BY: DIANA WHITNEY
DATE: 2-MARCH-2004

005

State of Utah

Department of
Natural Resources

Division of
Oil, Gas & Mining

ROBERT L. MORGAN
Executive Director

LOWELL P. BRAXTON
Division Director

MICHAEL O. LEAVITT
Governor

OLENE S. WALKER
Lieutenant Governor

March 3, 2004

Inland Production Company
Rt. #3, Box 3630
Myton, UT 84052

Re: Blackjack Federal 10-5-9-17 Well, 1676' FSL, 1982' FEL, NW SE, Sec. 5, T. 9 South, R. 17 East, Duchesne County, Utah

Gentlemen:

Pursuant to the provisions and requirements of Utah Code Ann.§ 40-6-1 *et seq.*, Utah Administrative Code R649-3-1 *et seq.*, and the attached Conditions of Approval, approval to drill the referenced well is granted.

This approval shall expire one year from the above date unless substantial and continuous operation is underway, or a request for extension is made prior to the expiration date. The API identification number assigned to this well is 43-013-32553.

Sincerely,

John R. Baza
Associate Director

pab
Enclosures

cc: Duchesne County Assessor
Bureau of Land Management, Vernal District Office

Operator: Inland Production Company

Well Name & Number Blackjack Federal 10-5-9-17

API Number: 43-013-32553

Lease: UTU-74808

Location: NW SE **Sec.** 5 **T.** 9 South **R.** 17 East

Conditions of Approval

1. General

   Compliance with the requirements of Utah Admin. R. 649-1 *et seq.*, the Oil and Gas Conservation General Rules, and the applicable terms and provisions of the approved Application for permit to drill.

2. Notification Requirements

   Notify the Division within 24 hours of spudding the well.

   - Contact Carol Daniels at (801) 538-5284.

   Notify the Division prior to commencing operations to plug and abandon the well.

   - Contact Dan Jarvis at (801) 538-5338

3. Reporting Requirements

   All required reports, forms and submittals will be promptly filed with the Division, including but not limited to the Entity Action Form (Form 6), Report of Water Encountered During Drilling (Form 7), Weekly Progress Reports for drilling and completion operations, and Sundry Notices and Reports on Wells requesting approval of change of plans or other operational actions.

4. State approval of this well does not supersede the required federal approval, which must be obtained prior to drilling.

United States Department of the Interior

BUREAU OF LAND MANAGEMENT
Utah State Office
P.O. Box 45155
Salt Lake City, UT 84145-0155
http://www.blm.gov

TAKE PRIDE IN AMERICA

IN REPLY REFER TO:
3106
(UT-924)

September 16, 2004

Memorandum

To: Vernal Field Office

From: Acting Chief, Branch of Fluid Minerals

Subject: Merger Approval

Attached is an approved copy of the name change recognized by the Utah State Office. We have updated our records to reflect the merger from Inland Production Company into Newfield Production Company on September 2, 2004.

Michael L Coulthard

Michael Coulthard
Acting Chief, Branch of
Fluid Minerals

Enclosure
1. State of Texas Certificate of Registration

cc: MMS, Reference Data Branch, James Sykes, PO Box 25165, Denver CO 80225
State of Utah, DOGM, Attn: Earlene Russell, PO Box 145801, SLC UT 84114
Teresa Thompson
Joe Incardine
Connie Seare

UTSL-
071572A
065914

UTU-

02458
03563
03563A
04493
05843
07978
09803
017439B
017985
017991
017992
018073
019222
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020252A
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020255
020309D
022684A
027345
034217A
035521
035521A
038797
058149
063597A
075174
096547
096550

10760
11385
13905
15392
15855
16535
16539
16544
17036
17424
18048
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26026A
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68528A
72086A
72613A
73520X
74477X
75023X
76189X
76331X
76788X
77098X
77107X
77236X
77376X
78560X
79485X
79641X
80207X
81307X

Corporations Section
P.O.Box 13697
Austin, Texas 78711-3697

Geoffrey S. Connor
Secretary of State

Office of the Secretary of State

The undersigned, as Secretary of State of Texas, does hereby certify that the attached is a true and correct copy of each document on file in this office as described below:

Newfield Production Company
Filing Number: 41530400

Articles of Amendment — September 02, 2004

In testimony whereof, I have hereunto signed my name officially and caused to be impressed hereon the Seal of State at my office in Austin, Texas on September 10, 2004.

Secretary of State

ARTICLES OF AMENDMENT
TO THE
ARTICLES OF INCORPORATION
OF
INLAND PRODUCTION COMPANY

FILED
In the Office of the
Secretary of State of Texas

SEP 02 2004

Corporations Section

Pursuant to the provisions of Article 4.04 of the Texas Business Corporation Act (the "TBCA"), the undersigned corporation adopts the following articles of amendment to the articles of incorporation:

ARTICLE 1 – Name

The name of the corporation is Inland Production Company.

ARTICLE 2 – Amended Name

The following amendment to the Articles of Incorporation was approved by the Board of Directors and adopted by the shareholders of the corporation on August 27, 2004.

The amendment alters or changes Article One of the Articles of Incorporation to change the name of the corporation so that, as amended, Article One shall read in its entirety as follows:

"ARTICLE ONE – The name of the corporation is Newfield Production Company."

ARTICLE 3 – Effective Date of Filing

This document will become effective upon filing.

The holder of all of the shares outstanding and entitled to vote on said amendment has signed a consent in writing pursuant to Article 9.10 of the TBCA, adopting said amendment, and any written notice required has been given.

IN WITNESS WHEREOF, the undersigned corporation has executed these Articles of Amendment as of the 1st day of September, 2004.

INLAND RESOURCES INC.

By: Susan G. Riggs
Susan G. Riggs, Treasurer

006

BLM VERNAL, UTAH

Form 3160-3
(September 2001)

FORM APPROVED
OMB No. 1004-0136
Expires January 31, 2004

UNITED STATES
DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

APPLICATION FOR PERMIT TO DRILL OR REENTER

5. Lease Serial No.
UTU-74808

6. If Indian, Allottee or Tribe Name
N/A

1a. Type of Work: ☒ DRILL ☐ REENTER

7. If Unit or CA Agreement, Name and No.
Blackjack

1b. Type of Well: ☒ Oil Well ☐ Gas Well ☐ Other ☒ Single Zone ☐ Multiple Zone

8. Lease Name and Well No.
Blackjack Federal 10-5-9-17

2. Name of Operator
Inland Production Company

9. API Well No.
43-013-32553

3a. Address
Route #3 Box 3630, Myton UT 84052

3b. Phone No. *(include area code)*
(435) 646-3721

10. Field and Pool, or Exploratory
Monument Butte

4. Location of Well *(Report location clearly and in accordance with any State requirements.*)*
At surface NW/SE 1676' FSL 1982' FEL
At proposed prod. zone

11. Sec., T., R., M., or Blk. and Survey or Area
NW/SE Sec. 5, T9S R17E

14. Distance in miles and direction from nearest town or post office*
Approximatley 13.5 miles southeast of Myton, Utah

12. County or Parish
Duchesne

13. State
UT

15. Distance from proposed* location to nearest property or lease line, ft. (Also to nearest drig. unit line, if any) Approx. 356' f/lse, 356' f/unit

16. No. of Acres in lease
232.46

17. Spacing Unit dedicated to this well
40 Acres

18. Distance from proposed location* to nearest well, drilling, completed, applied for, on this lease, ft. Approx. 1925'

19. Proposed Depth
6500'

20. BLM/BIA Bond No. on file
#4488944

21. Elevations (Show whether DF, KDB, RT, GL, etc.)
5251' GL

22. Approximate date work will start*
3rd Quarter 2004

23. Estimated duration
Approximately seven (7) days from spud to rig release.

24. Attachments

The following, completed in accordance with the requirements of Onshore Oil and Gas Order No.1, shall be attached to this form:

1. Well plat certified by a registered surveyor.
2. A Drilling Plan.
3. A Surface Use Plan (if the location is on National Forest System Lands, the SUPO shall be filed with the appropriate Forest Service Office).
4. Bond to cover the operations unless covered by an existing bond on file (see Item 20 above).
5. Operator certification.
6. Such other site specific information and/or plans as may be required by the authorized officer.

25. Signature Mandie Crozier | Name *(Printed/Typed)* Mandie Crozier | Date 2/27/04

Title
Regulatory Specialist

Approved by *(Signature)* Howard B. Cleavinger II | Name *(Printed/Typed)* | Date 10/08/2004

Title Assistant Field Manager
Mineral Resources | Office

Application approval does not warrant or certify the the applicant holds legal or equitable title to those rights in the subject lease which would entitle the applicant to conduct operations thereon.
Conditions of approval, if any, are attached.

Title 18 U.S.C. Section 1001 and Title 43 U.S.C. Section 1212, make it a crime for any person knowingly and willfully to make to any department or agency of the United States any false, fictitious or fraudulent statements or representations as to any matter within its jurisdiction.

*(Instructions on reverse)

NOV 22 2004

UDOGM
NOTICE OF APPROVAL

CONDITIONS OF APPROVAL ATTACHED

CONDITIONS OF APPROVAL
APPLICATION FOR PERMIT TO DRILL

Company/Operator:	Inland Production Company.
Well Name & Number:	Federal 10-5-9-17
API Number	43-013-32553
Lease Number:	U-74808
Location:	NWSE Sec. 5 T.9S R. 17E
Agreement:	Blackjack Unit

For more specific details on notification requirements, please check the Conditions of Approval for Notice to Drill and Surface Use Program.

CONDITIONS OF APPROVAL

Approval of this application does not warrant or certify that the applicant holds legal or equitable title to those rights in the subject lease which would entitle the applicant to conduct operations thereon.

Be aware fire restrictions may be in effect when location is being constructed and/or when well is being drilled. Contact the appropriate Surface Management Agency for information.

Please submit to this office, in LAS format, an electronic copy of all logs run on this well This submission will replace the requirement for submittal of paper logs to the BLM.

In the event after-hours approvals are necessary, you must contact one of the following individuals:

Ed Forsman (435) 828-7874
Petroleum Engineer

Kirk Fleetwood (435) 828-7875
Petroleum Engineer

BLM FAX Machine (435) 781-4410

**CONDITIONS OF APPROVAL
FOR THE SURFACE USE PROGRAM OF THE
APPLICATION FOR PERMIT TO DRILL**

Company/Operator: Inland Production Company

API Number: 43-013-32553

Well Name & Number: Federal 10-5-9-17

Lease Number: U-74808

Location: NWSE Sec. 5 T. 9 S. R. 17 E.

Surface Ownership: BLM

Date NOS Received: None

Date APD Received: 3-1-04

-No construction or drilling would be allowed from April 1 to August 15 to protect nesting mountain plovers, burrowing owls and red tail hawks unless a certified biologist determines that no nesting hawks are present.

-In order to reduce noise levels in the area, a hospital type muffler or multi cylinder engine shall be installed on the pumping unit.

-A certified paleontologist shall monitor the construction of the access road and well pad.

DIVISION OF OIL, GAS AND MINING

SPUDDING INFORMATION

Name of Company: INLAND PRODUCTION COMPANY

Well Name: BLACKJACK FED 10-5-9-17

Api No: 43-013-32553 Lease Type: FEDERAL

Section 05 Township 09S Range 17E County DUCHESNE

Drilling Contractor NDSI RIG # NS#1

SPUDDED:

Date 12/01/2004

Time NOON

How DRY

Drilling will commence:

Reported by FLOYD MITCHELL

Telephone # 1-435-823-3610

Date 12/02/2004 **Signed** CHD

008

STATE OF UTAH
DIVISION OF OIL, GAS AND MINING
ENTITY ACTION FORM -FORM 6

RECEIVED
DEC 0 3 2004
DIV. OF OIL, GAS & MINING

OPERATOR: Inland ~~NEWFIELD~~ PRODUCTION COMPANY
ADDRESS: RT. 3 BOX 3630
MYTON, UT 84052

OPERATOR ACCT. NO. N5160 ~~N2695~~

ACTION CODE	CURRENT ENTITY NO.	NEW ENTITY NO.	API NUMBER	WELL NAME	QQ	SC	TP	RG	COUNTY	SPUD DATE	EFFECTIVE DATE	
A	99999	14421	43-047-35090	Federal 10-1-9-17	NW/SE	1	9S	17E	Uintah	November 29, 2004	12/6/04	K

WELL 1 COMMENTS: GRRV

ACTION CODE	CURRENT ENTITY NO.	NEW ENTITY NO.	API NUMBER	WELL NAME	QQ	SC	TP	RG	COUNTY	SPUD DATE	EFFECTIVE DATE	
B	99999	12704	43-013-32553	BlackJack Federal 10-5-9-17	NW/SE	5	9S	17E	Duchesne	December 1, 2004	12/6/04	K

WELL 2 COMMENTS: GRRV

ACTION CODE	CURRENT ENTITY NO.	NEW ENTITY NO.	API NUMBER	WELL NAME	QQ	SC	TP	RG	COUNTY	SPUD DATE	EFFECTIVE DATE

WELL 3 COMMENTS:

ACTION	CURRENT	NEW	API NUMBER	WELL NAME	WELL LOCATION					SPUD	EFFECTIVE DATE

WELL 4 COMMENTS:

ACTION CODE	CURRENT ENTITY NO.	NEW ENTITY NO.	API NUMBER	WELL NAME	QQ	SC	TP	RG	COUNTY	SPUD DATE	EFFECTIVE DATE

WELL 5 COMMENTS:

ACTION CODES (See instructions on back of form)
- A - Establish new entity for new well (single well only)
- B - Add new well to existing entity (group or unit well)
- C - Re-assign well from one existing entity to another existing entity
- D - Re-assign well from one existing entity to a new entity
- E - Other (explain in comments section)

NOTE: Use COMMENT section to explain why each Action Code was selected.

(3/89)

Kebbie S. Jones Kebbie S. Jones
Signature

Production Clerk
Title

December 2, 2004
Date

COPY

FORM 3160-5
(September 2001)

UNITED STATES
DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

FORM APPROVED
OMB No. 1004-0135
Expires January 31,2004

009

SUNDRY NOTICES AND REPORTS ON WELLS

Do not use this form for proposals to drill or to re-enter an abandoned well. Use Form 3160-3 (APD) for such proposals.

SUBMIT IN TRIPLICATE - Other Instructions on reverse side

5. Lease Serial No.
UTU74808

6. If Indian, Allottee or Tribe Name.

7. If Unit or CA/Agreement, Name and/or No.
BLACKJACK UNIT

1. Type of Well
☒ Oil Well ☐ Gas Well ☐ Other

8. Well Name and No.
BLACKJACK FEDERAL 10-5-9-17

2. Name of Operator
Newfield Production Company

9. API Well No.
4301332553

3a. Address Route 3 Box 3630
Myton, UT 84052

3b. Phone No. *(include are code)*
435.646.3721

10. Field and Pool, or Exploratory Area
Monument Butte

4. Location of Well *(Footage, Sec., T., R., M., or Survey Description)*
1676 SFL 1982 EFL
NW/SE Section 5 T9S R17E

11. County or Parish, State
Duchesne,UT

12. CHECK APPROPRIATE BOX(ES) TO INIDICATE NATURE OF NOTICE, OR OTHER DATA

TYPE OF SUBMISSION	TYPE OF ACTION			
☐ Notice of Intent	☐ Acidize	☐ Deepen	☐ Production(Start/Resume)	☐ Water Shut-Off
☒ Subsequent Report	☐ Alter Casing	☐ Fracture Treat	☐ Reclamation	☐ Well Integrity
☐ Final Abandonment Notice	☐ Casing Repair	☐ New Construction	☐ Recomplete	☒ Other Spud Notice
	☐ Change Plans	☐ Plug & Abandon	☐ Temporarily Abandon	
	☐ Convert to Injector	☐ Plug Back	☐ Water Disposal	

13. Describe Proposed or Completed Operation (clearly state all pertinent details, including estimated starting date of any proposed work and approximate duration thereof. If the proposal is to deepen directionally or recomplete horizontally, give subsurface locations and measured and true vertical depths of all pertinent markers and zones. Attach the Bond under which the work will be performed or provide the Bond No. on file with BLM/BIA. Required subsequent reports shall be filed within 30 days following completion of the involved operations. If the operation results in a multiple completion or recompletion in a new interval, a Form 3160-4 shall be filed once testing has been completed. Final Abandonment Notices shall be filed only after all requirements, including reclamation, have been completed, and the operator has determined that the site is ready for final inspection.)

On 12-01-04 MIRU NDSI NS # 1.Spud well @ 12:00 PM. Drill 335' of 12 1/4" hole with air mist. TIH W/ 8 Jt's 8 5/8" J-55 24 # csgn. Set @ 335.05'/ KB On 12/03/04 cement with 160 sks class "G" cement W/2% CaCL2 + 1/4#/SK Cello Flake mixed @ 15.8 ppg 1.17 CF/SK yield Returned 4 bbls cement to pit. WOC.

RECEIVED
DEC 0 8 2004
DIV. OF OIL, GAS & MINING

I hereby certify that the foregoing is true and correct
Name *(Printed/ Typed)*
Floyd Mitchell

Title
Drilling Supervisor

Signature Floyd Mitchell

Date
12/6/2004

THIS SPACE FOR FEDERAL OR STATE OFFICE USE

Approved by .... Title Date

Conditions of approval, if any, are attached. Approval of this notice does not warrant or certify that the applicant holds legal or equitable title to those rights in the subject lease which would entitle the applicant to conduct operations thereon.

Office

Title 18 U.S.C. Section 1001 and Title 43 U.S.C. Section 1212, make it a crime for any person knowingly and willfully to make to any department or agency of the United States any false, fictitious and fraudulent statements or representations as to any matter within its jurisdiction

(Instructions on reverse)

NEWFIELD PRODUCTION COMPANY - CASING & CEMENT REPORT

8 5/8 CASING SET AT 333.05

LAST CASING 8 5/8" SET AT 333.05'
DATUM 12' KB
DATUM TO CUT OFF CASING
DATUM TO BRADENHEAD FLANGE
TD DRILLER 335' LOGGER
HOLE SIZE 12 1/4

OPERATOR Inland Production Company
WELL Black Jack 10-5-9-17
FIELD/PROSPECT Monument Butte
CONTRACTOR & RIG # NDSI NS #1

LOG OF CASING STRING:

PIECES	OD	ITEM - MAKE - DESCRIPTION	WT / FT	GRD	THREAD	CONDT	LENGTH
		Shoe Joint 36.05'					
		WHI - 92 csg head			8rd	A	0.95
8	8 5/8"	Maverick ST&C csg	24#	J-55	8rd	A	321.2
		GUIDE shoe			8rd	A	0.9

CASING INVENTORY BAL.	FEET	JTS
TOTAL LENGTH OF STRING	323.05	8
LESS NON CSG. ITEMS	1.85	
PLUS FULL JTS. LEFT OUT	0	
TOTAL	321.2	8
TOTAL CSG. DEL. (W/O THRDS)	321.2	8

} COMPARE

TOTAL LENGTH OF STRING	323.05
LESS CUT OFF PIECE	2
PLUS DATUM TO T/CUT OFF CSG	12
CASING SET DEPTH	**333.05**

TIMING		1ST STAGE	
BEGIN RUN CSG.	Spud	12/01/2004	12:00 PM
CSG. IN HOLE		12/02/2004	1:00 PM
BEGIN CIRC		12/3/2004	1:08 PM
BEGIN PUMP CMT		12/3/2004	1:15 PM
BEGIN DSPL. CMT		12/3/2004	1:26 PM
PLUG DOWN		**12/3/2004**	**1:35 PM**

GOOD CIRC THRU JOB Yes
Bbls CMT CIRC TO SURFACE 4
RECIPROCATED PIPE FOR ______ THRU ______ FT STROKE
DID BACK PRES. VALVE HOLD ? N/A
BUMPED PLUG TO 430 PSI

CEMENT USED		CEMENT COMPANY- **B. J.**
STAGE	# SX	CEMENT TYPE & ADDITIVES
1	160	Class "G" w/ 2% CaCL2 + 1/4#/sk Cello-Flake mixed @ 15.8 ppg 1.17 cf/sk yield

CENTRALIZER & SCRATCHER PLACEMENT	SHOW MAKE & SPACING
Centralizers - Middle first, top second & third for 3	

COMPANY REPRESENTATIVE Floyd Mitchell DATE 12/6/2004

FORM 3160-5
(September 2001)

UNITED STATES
DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

RECEIVED
DEC 2 1 2004
DIV. OF OIL, GAS & MINING

COPY

FORM APPROVED
OMB No. 10[illegible]
Expires [illegible] 2004

010

SUNDRY NOTICES AND REPORTS ON WELLS
Do not use this form for proposals to drill or to re-enter an abandoned well. Use Form 3160-3 (APD) for such proposals.

SUBMIT IN TRIPLICATE - Other Instructions on reverse side

5. Lease Serial No.
UTU74808

6. If Indian, Allottee or Tribe Name.

7. If Unit or CA/Agreement, Name and/or No.
BLACKJACK UNIT

1. Type of Well
☒ Oil Well ☐ Gas Well ☐ Other

8. Well Name and No.
BLACKJACK FEDERAL 10-5-9-17

2. Name of Operator
Newfield Production Company

9. API Well No.
4301332553

3a. Address Route 3 Box 3630
Myton, UT 84052

3b. Phone No. *(include are code)*
435.646.3721

10. Field and Pool, or Exploratory Area
Monument Butte

4. Location of Well *(Footage, Sec., T., R., M., or Survey Description)*
1676 ~~SFL~~ FSL 1982 ~~EFL~~ FEL
NW/SE Section 5 T9S R17E

11. County or Parish, State
Duchesne,UT

12. CHECK APPROPRIATE BOX(ES) TO INIDICATE NATURE OF NOTICE, OR OTHER DATA

TYPE OF SUBMISSION	TYPE OF ACTION			
☐ Notice of Intent	☐ Acidize	☐ Deepen	☐ Production(Start/Resume)	☐ Water Shut-Off
☒ Subsequent Report	☐ Alter Casing	☐ Fracture Treat	☐ Reclamation	☐ Well Integrity
☐ Final Abandonment Notice	☐ Casing Repair	☐ New Construction	☐ Recomplete	☒ Other Weekly Status Report
	☐ Change Plans	☐ Plug & Abandon	☐ Temporarily Abandon	
	☐ Convert to Injector	☐ Plug Back	☐ Water Disposal	

13. Describe Proposed or Completed Operation (clearly state all pertinent details, including estimated starting date of any proposed work and approximate duration thereof. If the proposal is to deepen directionally or recomplete horizontally, give subsurface locations and measured and true vertical depths of all pertinent markers and zones. Attach the Bond under which the work will be performed or provide the Bond No. on file with BLM/BIA. Required subsequent reports shall be filed within 30 days following completion of the involved operations. If the operation results in a multiple completion or recompletion in a new interval, a Form 3160-4 shall be filed once testing has been completed. Final Abandonment Notices shall be filed only after all requirements, including reclamation, have been completed, and the operator has determined that the site is ready for final inspection.)

On 12/09/04 MIRU Patterson Rig # 155. Set all equipment. Pressure test Kelly, TIW, Choke manifold, & Bop's to 2,000 psi. Test 8.625 csgn to 1,500 psi. Vernal BLM field, & Roosevelt DOGM office was notifed of test. PU BHA and tag cement @ 290'. Drill out cement & shoe. Drill a 7.875 hole with fresh water to a depth of 6,015'. Lay down drill string & BHA. Open hole log w/ Dig/SP/GR log's TD to surface. PU & TIH with Guide shoe, shoe jt, float collar, 141 jt's of 5.5 J-55, 15.5# csgn. Set @ 5985.35' / KB. Cement with 350 sks cement mixed @ 11.0 ppg & 3.43 yld. The 400 sks cement mixed @ 14.4 ppg & 1.24 yld. With 17 BBLS cement returned to pit. Nipple down Bop's. Drop slips @ 85,000 #'s tension. Release rig 11:30 pm on 12/14/04.

I hereby certify that the foregoing is true and correct Name *(Printed/ Typed)* Floyd Mitchell	Title Drilling Supervisor
Signature Floyd Mitchell	Date 12/15/2004

THIS SPACE FOR FEDERAL OR STATE OFFICE USE

Approved by	Title	Date
Conditions of approval, if any, are attached. Approval of this notice does not warrant or certify that the applicant holds legal or equitable title to those rights in the subject lease which would entitle the applicant to conduct operations thereon.	Office	

Title 18 U.S.C. Section 1001 and Title 43 U.S.C. Section 1212, make it a crime for any person knowingly and willfully to make to any department or agency of the United States any false, fictitious and fraudulent statements or representations as to any matter within its jurisdiction

(Instructions on reverse)

NEWFIELD PRODUCTION COMPANY - CASING & CEMENT REPORT

5 1/2" CASING SET AT 5985.35

Flt cllr @ 5944'

LAST CASING 8 5/8" SET AT 333.05'

OPERATOR Newfield Production Company

DATUM 12' KB

WELL Black Jack 10-5-9-17

DATUM TO CUT OFF CASING 12'

FIELD/PROSPECT Monument Butte

DATUM TO BRADENHEAD FLANGE

CONTRACTOR & RIG # Patterson # 155

TD DRILLER 6015' LOGGER 5997'

HOLE SIZE 7 7/8"

LOG OF CASING STRING:

PIECES	OD	ITEM - MAKE - DESCRIPTION	WT / FT	GRD	THREAD	CONDT	LENGTH
		5.86' short jt @ 3990'					
141	5 1/2"	ETC LT & C casing	15.5#	J-55	8rd	A	5944.53
		Float collar					0.6
1	5 1/2"	ETC LT&C csg	15.5#	J-55	8rd	A	43.13
		GUIDE shoe			8rd	A	0.65

CASING INVENTORY BAL.	FEET	JTS
TOTAL LENGTH OF STRING	5988.91	142
LESS NON CSG. ITEMS	15.25	
PLUS FULL JTS. LEFT OUT	168.9	4
TOTAL	6142.56	146
TOTAL CSG. DEL. (W/O THRDS)	6156.56	146

TOTAL LENGTH OF STRING	5988.91
LESS CUT OFF PIECE	15.56
PLUS DATUM TO T/CUT OFF CSG	12
CASING SET DEPTH	5985.35

} COMPARE

TIMING	1ST STAGE	2nd STAGE
BEGIN RUN CSG.	12/14/2004	1:00 PM
CSG. IN HOLE	12/14/2004	4:00 PM
BEGIN CIRC	12/14/2004	4:00 PM
BEGIN PUMP CMT	12/14/2004	5:17 PM
BEGIN DSPL. CMT	12/14/2004	6:14 PM
PLUG DOWN	12/14/2004	6:36 PM

GOOD CIRC THRU JOB Yes

Bbls CMT CIRC TO SURFACE 17

RECIPROCATED PIPE FOR THRUSTROKE

DID BACK PRES. VALVE HOLD ? YES

BUMPED PLUG TO 2117 PSI

CEMENT USED		CEMENT COMPANY- B. J.
STAGE	# SX	CEMENT TYPE & ADDITIVES
1	350	Premlite II w/ 10% gel + 3 % KCL, 3#'s /sk CSE + 2# sk/kolseal + 1/4#'s/sk Cello Flake
		mixed @ 11.0 ppg W / 3.43 cf/sk yield
2	400	50/50 poz W/ 2% Gel + 3% KCL, .5%EC1,1/4# sk C.F. 2% gel. 3% SM mixed @ 14.4 ppg W/ 1.24 YLD

CENTRALIZER & SCRATCHER PLACEMENT	SHOW MAKE & SPACING
Centralizers - Middle first, top second & third. Then every third collar for a total of 20.	

COMPANY REPRESENTATIVE Floyd Mitchell

DATE 12/15/2004

FORM 3160-5
(September 2001)

UNITED STATES
DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

RECEIVED
JAN 13 2005
DIV. OF OIL, GAS & MINING

COPY

FORM APPROVED
OMB No. 1004-0135
Expires January 31, 2004

SUNDRY NOTICES AND REPORTS ON WELLS

Do not use this form for proposals to drill or to re-enter an abandoned well. Use Form 3160-3 (APD) for such proposals.

011

SUBMIT IN TRIPLICATE - Other Instructions on reverse side

5. Lease Serial No.
UTU74808

6. If Indian, Allottee or Tribe Name.

7. If Unit or CA/Agreement, Name and/or No.
BLACKJACK UNIT

8. Well Name and No.
BLACKJACK FEDERAL 10-5-9-17

9. API Well No.
4301332553

10. Field and Pool, or Exploratory Area
Monument Butte

11. County or Parish, State
Duchesne,UT

1. Type of Well
☒ Oil Well ☐ Gas Well ☐ Other

2. Name of Operator
Newfield Production Company

3a. Address Route 3 Box 3630
Myton, UT 84052

3b. Phone No. *(include are code)*
435.646.3721

4. Location of Well *(Footage, Sec., T., R., M., or Survey Description)*
1676 SFL 1982 EFL
NW/SE Section 5 T9S R17E

12. CHECK APPROPRIATE BOX(ES) TO INIDICATE NATURE OF NOTICE, OR OTHER DATA

TYPE OF SUBMISSION	TYPE OF ACTION			
☐ Notice of Intent	☐ Acidize	☐ Deepen	☐ Production(Start/Resume)	☐ Water Shut-Off
☒ Subsequent Report	☐ Alter Casing	☐ Fracture Treat	☐ Reclamation	☐ Well Integrity
☐ Final Abandonment Notice	☐ Casing Repair	☐ New Construction	☐ Recomplete	☒ Other
	☐ Change Plans	☐ Plug & Abandon	☐ Temporarily Abandon	Weekly Status Report
	☐ Convert to Injector	☐ Plug Back	☐ Water Disposal	

13. Describe Proposed or Completed Operation (clearly state all pertinent details, including estimated starting date of any proposed work and approximate duration thereof. If the proposal is to deepen directionally or recomplete horizontally, give subsurface locations and measured and true vertical depths of all pertinent markers and zones. Attach the Bond under which the work will be performed or provide the Bond No. on file with BLM/BIA. Required subsequent reports shall be filed within 30 days following completion of the involved operations. If the operation results in a multiple completion or recompletion in a new interval, a Form 3160-4 shall be filed once testing has been completed. Final Abandonment Notices shall be filed only after all requirements, including reclamation, have been completed, and the operator has determined that the site is ready for final inspection.)

Status report for time period 12/30/04 – 01/11/05
Subject well had completion procedures initiated in the Green River formation on 12/30/04 without the use of a service rig over the well. A cement bond log was run and a total of seven Green River intervals were perforated and hydraulically fracture treated w/ 20/40 mesh sand. Perf intervals were #1 (5822-5832') (4 JSPF); #2 (5667-5673'), (5580-5590'), (5542-5550') (ALL 4 JSPF); #3 (5334-5366'), (5300-5320') (ALL 4 JSPF); #4 (5102-5112') (4 JSPF); #5 (4714-4724') (4 JSPF); #6 (4228-4238') (4 JSPF); #7 (4092-4097') (4 JSPF). Composite flow-through frac plugs were used between stages. Fracs were flowed back through chokes. A service rig was moved on well on 1/06/05. Bridge plugs were drilled out. Well was cleaned out to PBTD @ 5859'. Zones were swab tested for sand cleanup. A BHA & production tbg string were run in and anchored in well. End of tubing string @ 5757.63'. A new 1 1/2" bore rod pump was run in well on sucker rods. Well was placed on production via rod pump on 1/11/05.

I hereby certify that the foregoing is true and correct
Name *(Printed/ Typed)*
Renee Palmer

Title
Production Clerk

Signature

Date
1/12/2005

THIS SPACE FOR FEDERAL OR STATE OFFICE USE

Approved by ....

Title

Date

Conditions of approval, if any, are attached. Approval of this notice does not warrant or certify that the applicant holds legal or equitable title to those rights in the subject lease which would entitle the applicant to conduct operations thereon.

Office

(Instructions on reverse)

Division of Oil, Gas and Mining

OPERATOR CHANGE WORKSHEET

ROUTING
1. GLH
2. CDW
3. FILE

012

Change of Operator (Well Sold)   Designation of Agent/Operator

X **Operator Name Change**   **Merger**

The operator of the well(s) listed below has changed, effective: **9/1/2004**

FROM: (Old Operator):	**TO:** (New Operator):
N5160-Inland Production Company	N2695-Newfield Production Company
Route 3 Box 3630	Route 3 Box 3630
Myton, UT 84052	Myton, UT 84052
Phone: 1-(435) 646-3721	Phone: 1-(435) 646-3721

CA No.   **Unit:** **BLACKJACK (GR)**

WELL(S)

NAME	SEC	TWN	RNG	API NO	ENTITY NO	LEASE TYPE	WELL TYPE	WELL STATUS	
BLACKJACK FED 9-9-9-17	09	090S	170E	4301332517	12704	Federal	OW	P	K
BLACKJACK FED 8-5-9-17	05	090S	170E	4301332552	12704	Federal	OW	DRL	K
BLACKJACK FED 10-5-9-17	05	090S	170E	4301332553	12704	Federal	OW	DRL	K
BLACKJACK FED 7-5-9-17	05	090S	170E	4301332554	12704	Federal	OW	P	K
BLACKJACK FED 1-5-9-17	05	090S	170E	4301332555	12704	Federal	OW	APD	K
BLACKJACK FED 16-33-8-17	33	080S	170E	4301332632		Federal	OW	APD	K
BLACKJACK FED 14-33-8-17	33	080S	170E	4301332633		Federal	OW	APD	K
BLACKJACK FED 1-4-9-17	04	090S	170E	4301332635		Federal	OW	APD	K

OPERATOR CHANGES DOCUMENTATION

Enter date after each listed item is completed

1. (R649-8-10) Sundry or legal documentation was received from the **FORMER** operator on: 9/15/2004
2. (R649-8-10) Sundry or legal documentation was received from the **NEW** operator on: 9/15/2004
3. The new company was checked on the **Department of Commerce, Division of Corporations Database on:** 2/23/2005
4. Is the new operator registered in the State of Utah: YES Business Number: 755627-0143
5. If **NO**, the operator was contacted contacted on:

6a. (R649-9-2)Waste Management Plan has been received on: IN PLACE

6b. Inspections of LA PA state/fee well sites complete on: waived

7. **Federal and Indian Lease Wells:** The BLM and or the BIA has approved the merger, name change, or operator change for all wells listed on Federal or Indian leases on: BLM BIA

8. **Federal and Indian Units:**
The BLM or BIA has approved the successor of unit operator for wells listed on: n/a

9. **Federal and Indian Communization Agreements ("CA"):**
The BLM or BIA has approved the operator for all wells listed within a CA on: na/

10. **Underground Injection Control ("UIC")** The Division has approved UIC Form 5, **Transfer of Authority to Inject,** for the enhanced/secondary recovery unit/project for the water disposal well(s) listed on: 2/23/2005

DATA ENTRY:

1. Changes entered in the **Oil and Gas Database on:** 2/28/2005
2. Changes have been entered on the **Monthly Operator Change Spread Sheet on:** 2/28/2005
3. Bond information entered in RBDMS on: 2/28/2005
4. Fee/State wells attached to bond in RBDMS on: 2/28/2005
5. Injection Projects to new operator in RBDMS on: 2/28/2005
6. Receipt of Acceptance of Drilling Procedures for APD/New on: waived

FEDERAL WELL(S) BOND VERIFICATION:

1. Federal well(s) covered by Bond Number: UT 0056

INDIAN WELL(S) BOND VERIFICATION:

1. Indian well(s) covered by Bond Number: 61BSBDH2912

FEE & STATE WELL(S) BOND VERIFICATION:

1. (R649-3-1) The **NEW** operator of any fee well(s) listed covered by Bond Number 61BSBDH2919

2. The **FORMER** operator has requested a release of liability from their bond on: n/a*
The Division sent response by letter on: n/a

LEASE INTEREST OWNER NOTIFICATION:

3. (R649-2-10) The **FORMER** operator of the fee wells has been contacted and informed by a letter from the Division of their responsibility to notify all interest owners of this change on: n/a

COMMENTS:

*Bond rider changed operator name from Inland Production Company to Newfield Production Company - **received 2/23/05**

Division of Oil, Gas and Mining

OPERATOR CHANGE WORKSHEET

ROUTING
1. GLH
2. CDW
3. FILE

013

Change of Operator (Well Sold)

Designation of Agent/Operator

X **Operator Name Change**

Merger

The operator of the well(s) listed below has changed, effective:	9/1/2004
FROM: (Old Operator): N5160-Inland Production Company Route 3 Box 3630 Myton, UT 84052 Phone: 1-(435) 646-3721	**TO:** (New Operator): N2695-Newfield Production Company Route 3 Box 3630 Myton, UT 84052 Phone: 1-(435) 646-3721
CA No.	**Unit:** BLACKJACK (GR)

WELL(S)

NAME	SEC	TWN	RNG	API NO	ENTITY NO	LEASE TYPE	WELL TYPE	WELL STATUS	
BLACKJACK FED 9-9-9-17	09	090S	170E	4301332517	12704	Federal	OW	P	K
BLACKJACK FED 8-5-9-17	05	090S	170E	4301332552	12704	Federal	OW	DRL	K
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BLACKJACK FED 7-5-9-17	05	090S	170E	4301332554	12704	Federal	OW	P	K
BLACKJACK FED 1-5-9-17	05	090S	170E	4301332555	12704	Federal	OW	APD	K
BLACKJACK FED 16-33-8-17	33	080S	170E	4301332632		Federal	OW	APD	K
BLACKJACK FED 14-33-8-17	33	080S	170E	4301332633		Federal	OW	APD	K
BLACKJACK FED 1-4-9-17	04	090S	170E	4301332635		Federal	OW	APD	K

OPERATOR CHANGES DOCUMENTATION

Enter date after each listed item is completed

1. (R649-8-10) Sundry or legal documentation was received from the **FORMER** operator on: 9/15/2004
2. (R649-8-10) Sundry or legal documentation was received from the **NEW** operator on: 9/15/2004
3. The new company was checked on the **Department of Commerce, Division of Corporations Database on:** 2/23/2005
4. Is the new operator registered in the State of Utah: YES Business Number: 755627-0143
5. If **NO**, the operator was contacted contacted on:

6a. (R649-9-2)Waste Management Plan has been received on: IN PLACE
6b. Inspections of LA PA state/fee well sites complete on: waived

7. **Federal and Indian Lease Wells:** The BLM and or the BIA has approved the merger, name change, or operator change for all wells listed on Federal or Indian leases on: BLM BIA

8. **Federal and Indian Units:**
The BLM or BIA has approved the successor of unit operator for wells listed on: n/a

9. **Federal and Indian Communization Agreements ("CA"):**
The BLM or BIA has approved the operator for all wells listed within a CA on: na/

10. **Underground Injection Control ("UIC")** The Division has approved UIC Form 5, **Transfer of Authority to Inject,** for the enhanced/secondary recovery unit/project for the water disposal well(s) listed on: 2/23/2005

DATA ENTRY:

1. Changes entered in the **Oil and Gas Database on:** 2/28/2005
2. Changes have been entered on the **Monthly Operator Change Spread Sheet on:** 2/28/2005
3. Bond information entered in RBDMS on: 2/28/2005
4. Fee/State wells attached to bond in RBDMS on: 2/28/2005
5. Injection Projects to new operator in RBDMS on: 2/28/2005
6. Receipt of Acceptance of Drilling Procedures for APD/New on: waived

FEDERAL WELL(S) BOND VERIFICATION:

1. Federal well(s) covered by Bond Number: UT 0056

INDIAN WELL(S) BOND VERIFICATION:

1. Indian well(s) covered by Bond Number: 61BSBDH2912

FEE & STATE WELL(S) BOND VERIFICATION:

1. (R649-3-1) The **NEW** operator of any fee well(s) listed covered by Bond Number 61BSBDH2919

2. The **FORMER** operator has requested a release of liability from their bond on: n/a*
The Division sent response by letter on: n/a

LEASE INTEREST OWNER NOTIFICATION:

3. (R649-2-10) The **FORMER** operator of the fee wells has been contacted and informed by a letter from the Division of their responsibility to notify all interest owners of this change on: n/a

COMMENTS:

*Bond rider changed operator name from Inland Production Company to Newfield Production Company - **received 2/23/05**

FORM 3160-4
(July 1992)

SUBMIT IN DUPLICATE*
(See other instructions ons reverse side)

FORM APPROVED
OMB NO. 1004-0137
Expires: February 28, 1995

014

UNITED STATES
DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

WELL COMPLETION OR RECOMPLETION REPORT AND LOG*

5. LEASE DESIGNATION AND SERIAL NO.: UTU-74808

6. IF INDIAN, ALLOTTEE OR TRIBE NAME: NA

7. UNIT AGREEMENT NAME: Blackjack Unit

1a. TYPE OF WORK: OIL WELL [X] GAS WELL [ ] DRY [ ] Other

1b. TYPE OF WELL: NEW WELL [X] WORK OVER [ ] DEEPEN [ ] PLUG BACK [ ] DIFF RESVR. [ ] Other

8. FARM OR LEASE NAME, WELL NO.: BLACKJACK FEDERAL 10-5-9-17

9. WELL NO.: 43-013-32553

2. NAME OF OPERATOR: Newfield Exploration Company

10. FIELD AND POOL OR WILDCAT: Monument Butte

3. ADDRESS AND TELEPHONE NO.: 1401 17th St. Suite 1000 Denver, CO 80202

4. LOCATION OF WELL (Report locations clearly and in accordance with any State requirements.*)
At Surface: 1676' FSL & 1982' FEL (NW SE) Sec. 5, Twp 9S, Rng 17E
At top prod. Interval reported below
At total depth

11. SEC., T., R., M., OR BLOCK AND SURVEY OR AREA: Sec. 5, T9S, R17E

14. API NO.: 43-013-32553 | DATE ISSUED: 3/3/2004

12. COUNTY OR PARISH: Duchesne | 13. STATE: UT

15. DATE SPUDDED	16. DATE T.D. REACHED	17. DATE COMPL. (Ready to prod.)	18. ELEVATIONS (DF, RKB, RT, GR, ETC.)*	19. ELEV. CASINGHEAD
12/1/2004	12/14/2004	1/10/2005	5251' GL 5263' KB	

20. TOTAL DEPTH, MD & TVD	21. PLUG BACK T.D., MD & TVD	22. IF MULTIPLE COMPL., HOW MANY*	23. INTERVALS DRILLED BY	ROTARY TOOLS	CABLE TOOLS
6015'	5940'		------>	X	

24. PRODUCING INTERVAL(S), OF THIS COMPLETION--TOP, BOTTOM, NAME (MD AND TVD)*: Green River 4092'-5832'

25. WAS DIRECTIONAL SURVEY MADE: No

26. TYPE ELECTRIC AND OTHER LOGS RUN: Dual Induction Guard, SP, Compensated Density, Compensated Neutron, GR, Caliper, Cement Bond Log

27. WAS WELL CORED: No

23. CASING RECORD (Report all strings set in well)

CASING SIZE/GRADE	WEIGHT, LB./FT.	DEPTH SET (MD)	HOLE SIZE	TOP OF CEMENT, CEMENTING RECORD	AMOUNT PULLED
8-5/8" - J-55	24#	333'	12-1/4"	To surface with 160 sx Class "G" cmt	
5-1/2" - J-55	15.5#	5985'	7-7/8"	350 sx Premlite II and 400 sx 50/50 Poz	

29. LINER RECORD

SIZE	TOP (MD)	BOTTOM (MD)	SACKS CEMENT*	SCREEN (MD)

30. TUBING RECORD

SIZE	DEPTH SET (MD)	PACKER SET (MD)
2-7/8"	EOT @ 5757'	TA @ 5653'

31. PERFORATION RECORD (Interval, size and number)

INTERVAL	SIZE	SPF/NUMBER
(CP5) 5822'-5832'	.041"	4/40
(CP.5,1,3) 5542-52', 5580-90', 5667-73'	.041"	4/96
(LODC) 5300-20', 5334-66'	.041"	4/104
(A3) 5102'-5112'	.041"	4/40
(D2) 4714'-4724'	.041"	4/40
(GB6) 4228'-4238'	.041"	4/40
(GB2) 4092'-4097'	.041"	4/20

32. ACID, SHOT, FRACTURE, CEMENT SQUEEZE, ETC.

DEPTH INTERVAL (MD)	AMOUNT AND KIND OF MATERIAL USED
5822'-5832'	Frac w/ 18,712# 20/40 sand in 268 bbls fluid.
5542'-5673'	Frac w/ 64,105# 20/40 sand in 524 bbls fluid.
5300'-5366'	Frac w/ 199,147# 20/40 sand in 1337 bbls fluid.
5102'-5112'	Frac w/ 44,330# 20/40 sand in 411 bbls fluid.
4714'-4724'	Frac w/ 19,177# 20/40 sand in 241 bbls fluid.
4228'-4238'	Frac w/ 63,938# 20/40 sand in 493 bbls fluid.
4092'-4097'	Frac w/ 14,210# 20/40 sand in 230 bbls fluid.

33.* PRODUCTION

DATE FIRST PRODUCTION	PRODUCTION METHOD (Flowing, gas lift, pumping--size and type of pump)	WELL STATUS (Producing or shut-in)
1/10/2005	2-1/2" x 1-1/2" x 14' RHAC Pump	PRODUCING

DATE OF TEST	HOURS TESTED	CHOKE SIZE	PROD'N. FOR TEST PERIOD	OIL--BBLS.	GAS--MCF.	WATER--BBL.	GAS-OIL RATIO
10 day ave			--->	99	29	12	293

FLOW. TUBING PRESS.	CASING PRESSURE	CALCULATED 24-HOUR RATE	OIL-BBL.	GAS--MCF.	WATER--BBL.	OIL GRAVITY-API (CORR.)
		--->				

RECEIVED
MAR 30 2005
DIV. OF OIL, GAS & MINING

34. DISPOSITION OF GAS (Sold, used for fuel, vented, etc.): Sold & Used for Fuel

TEST WITNESSED BY

35. LIST OF ATTACHMENTS

36. I hereby certify that the foregoing and attached information is complete and correct as determined from all available records

SIGNED Krisha Russell TITLE Production Clerk DATE

Krisha Russell

KR

*(See Instructions and Spaces for Additional Data on Reverse Side)

37. SUMMARY OF POROUS ZONES: (Show all important zones of porosity and contents thereof; cored intervals, and all drill-stem, tests, including depth interval tested, cushion used, time tool open, flowing and shut-in pressures, and recoveries);

FORMATION	TOP	BOTTOM	DESCRIPTION, CONTENTS, ETC.
			Well Name **Blackjack 10-5-9-17**

38. **GEOLOGIC MARKERS**

NAME	TOP MEAS. DEPTH	TOP TRUE VERT. DEPTH
Garden Gulch Mkr	3673'	
Garden Gulch 1	3867'	
Garden Gulch 2	3977'	
Point 3 Mkr	4239'	
X Mkr	4479'	
Y-Mkr		
Douglas Creek Mkr	4640'	
BiCarbonate Mkr	4869'	
B Limestone Mkr	4944'	
Castle Peak		
Basal Carbonate	5937'	
Total Depth (LOGGERS)		

FORM 3160-5
(September 2001)

UNITED STATES
DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

FORM APPROVED
OMB No. 1004-0135
Expires January 31,2004

SUNDRY NOTICES AND REPORTS ON WELLS
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015

SUBMIT IN TRIPLICATE - Other Instructions on reverse side

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UTU74808

6. If Indian, Allottee or Tribe Name.

7. If Unit or CA/Agreement, Name and/or No.
BLACKJACK UNIT

8. Well Name and No.
BLACKJACK FEDERAL 10-5-9-17

9. API Well No.
4301332553

10. Field and Pool, or Exploratory Area
Monument Butte

11. County or Parish, State
Duchesne,UT

1. Type of Well
☒ Oil Well ☐ Gas Well ☐ Other

2. Name of Operator
Newfield Production Company

3a. Address Route 3 Box 3630
Myton, UT 84052

3b. Phone No. *(include are code)*
435.646.3721

4. Location of Well *(Footage, Sec., T., R., M., or Survey Description)*
1676 SFL 1982 EFL
NW/SE Section 5 T9S R17E

12. CHECK APPROPRIATE BOX(ES) TO INIDICATE NATURE OF NOTICE, OR OTHER DATA

TYPE OF SUBMISSION	TYPE OF ACTION			
☒ Notice of Intent	☐ Acidize	☐ Deepen	☐ Production(Start/Resume)	☐ Water Shut-Off
☐ Subsequent Report	☐ Alter Casing	☐ Fracture Treat	☐ Reclamation	☐ Well Integrity
☐ Final Abandonment Notice	☐ Casing Repair	☐ New Construction	☐ Recomplete	☒ Other Variance
	☐ Change Plans	☐ Plug & Abandon	☐ Temporarily Abandon	
	☐ Convert to Injector	☐ Plug Back	☐ Water Disposal	

13. Describe Proposed or Completed Operation (clearly state all pertinent details, including estimated starting date of any proposed work and approximate duration thereof. If the proposal is to deepen directionally or recomplete horizontally, give subsurface locations and measured and true vertical depths of all pertinent markers and zones. Attach the Bond under which the work will be performed or provide the Bond No. on file with BLM/BIA. Required subsequent reports shall be filed within 30 days following completion of the involved operations. If the operation results in a multiple completion or recompletion in a new interval, a Form 3160-4 shall be filed once testing has been completed. Final Abandonment Notices shall be filed only after all requirements, including reclamation, have been completed, and the operator has determined that the site is ready for final inspection.)

Newfield Production Company is requesting a variance from Onshore Order 43 CFR Part 3160 Section 4 requiring production tanks to be equipped with Enardo or equivalent vent line valves. Inland operates wells that produce from the Green River formation, which are relatively low gas producers (20 mcfpd). The majority of the wells are equipped with a three phase separator to maximize gas separation and sales.

Newfield is requesting a variance for safety reasons. Crude oil production tanks equipped with back pressure devices will emit a surge of gas when the thief hatches are open. While gauging tanks, lease operators will be subject to breathing toxic gases as well as risk a fire hazard, under optimum conditions.

COPY SENT TO OPERATOR
Date: 4-5-05
Initials: CHD

I hereby certify that the foregoing is true and correct
Name *(Printed/ Typed)*
Mandie Crozier

Title
Regulatory Specialist

Signature Mandie Crozier

Date 3/31/05

THIS SPACE FOR FEDERAL OR STATE OFFICE USE

Approved by

Title

Date

Conditions of approval, if any, are attached. Approval of this notice does not warrant or certify that the applicant holds legal or equitable title to those rights in the subject lease which would entitle the applicant to conduct operations thereon.

Accepted by the Utah Division of Oil, Gas and Mining

Federal Approval Of This Action Is Necessary

Date: 4/4/05
By: [signature]

Title 18 U.S.C. Section 1001 and Title 43 U.S.C. Section 1212, make it a crime for any person knowingly and willfully to make to any department or agency of the United States any false, fictitious and fraudulent statements or representations as to any matter within its jurisdiction.

(Instructions on reverse)

RECEIVED
APR 04 2005
DIV. OF OIL, GAS & MINING

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 8
999 18th STREET - SUITE 300
DENVER, CO 80202-2466
http://www.epa.gov/region08

DEC 14 2006

Ref: 8P-W-GW

CERTIFIED MAIL
RETURN RECEIPT REQUESTED

Accepted by the Utah Division of Oil, Gas and Mining
FOR RECORD ONLY

David Gerbig
Newfield Production Company
1401 Seventeenth Street
Suite 1000
Denver, CO 80202

43.013.32553
9S 17E 5

Re: Underground Injection Control Program
Final Permit: Blackjack Federal 10-5-9-17
Duchesne County, Utah
EPA Permit No. UT20998-06753

Dear Mr. Gerbig:

Enclosed is your copy of the FINAL Underground Injection Control (UIC) Permit for the proposed Blackjack Federal 10-5-9-17 injection well. A Statement of Basis, which discusses development of the conditions and requirements of the Permit, also is included.

The Public Comment period ended on DEC 08 2006. There were no comments on the Draft Permit received during the Public Notice period, and therefore the Final Permit becomes effective on the date of issuance. All conditions set forth herein refer to Title 40 Parts 124, 144, 146, and 147 of the Code of Federal Regulations (CFR) and are regulations that are in effect on the date that this Permit becomes effective.

Please note that under the terms of the Final Permit, you are authorized only to construct the proposed injection well, and must fulfill the "Prior to Commencing Injection" requirements of the Permit, Part II Section C Subpart 1 and obtain written Authorization to Inject prior to commencing injection. It is your responsibility to be familiar with and to comply with all provisions of the Final Permit.

The Permit and the authorization to inject are issued for the operating life of the well unless terminated (Part III, Section B). The EPA will review this Permit at least every five (5) years to determine whether action under 40 CFR § 144.36(a) is warranted.

RECEIVED
DEC 18 2006
DIV. OF OIL, GAS & MINING

If you have any questions on the enclosed Final Permit or Statement of Basis, please call Emmett Schmitz of my staff at (303) 312-6174, or toll-free at (800) 227-8917, ext. 6174.

Sincerely,

Carol L. Campbell for

Stephen S. Tuber
Assistant Regional Administrator
Office of Partnerships and Regulatory Assistance

enclosure: Final UIC Permit
Statement of Basis
Form 7520-7 Application to Transfer Permit
Form 7520-11 Monitoring Report
Form 7520-12 Well Rework Record
Form 7520-13 Plugging Record
Groundwater Section Guidance 35
Groundwater Section Guidance 37
Groundwater Section Guidance 39

cc: Letter only:

Maxine Natchees
Acting Chairperson
Uintah & Ouray Business Committee
Ute Indian Tribe

Chester Mills
Superintendent
Uintah & Ouray Indian Agency
U.S. Bureau of Indian Affairs

Final Permit & Statement of Basis:

Lynn Becker
Director
Energy & Minerals Dept.
Ute Indian Tribe

Shaun Chapoose
Director
Land Use Dept.
Ute Indian Tribe

Gilbert Hunt
Assistant Director
State of Utah - Natural Resources

Fluid Minerals Engineering Office
U.S. Bureau of Land Management
Vernal, Utah

all enclosures:

Michael Guinn
Vice President - Operations
Newfield Production Company
Myton, Utah

EPA

UNDERGROUND INJECTION CONTROL PROGRAM

PERMIT

PREPARED: December 2006

Permit No. UT20998-06753

Class II Enhanced Oil Recovery Injection Well

Blackjack Federal 10-5-9-17
DUCHESNE County, UT

Issued To

Newfield Production Company

1401 Seventeenth Street

Suite 1000

Denver, CO 80202

Part I. AUTHORIZATION TO CONSTRUCT AND OPERATE

Under the authority of the Safe Drinking Water Act and Underground Injection Control (UIC) Program regulations of the U. S. Environmental Protection Agency (EPA) codified at Title 40 of the Code of Federal Regulations (40 CFR) Parts 2, 124, 144, 146, and 147, and according to the terms of this Permit,

Newfield Production Company 1401 Seventeenth Street Suite 1000 Denver, CO 80202

is authorized to construct and to operate the following Class II injection well or wells:

Blackjack Federal 10-5-9-17 1676' FSL & 1982' FEL, NWSE S5, T9S, R17E DUCHESNE County, UT

EPA UIC permits regulate the injection of fluids into underground injection wells so that the injection does not endanger underground sources of drinking water. EPA UIC permit conditions are based upon the authorities set forth in regulatory provisions at 40 CFR Parts 144 and 146, and address potential impacts to underground sources of drinking water.

Under 40 CFR Part 144, Subpart D, certain conditions apply to all UIC permits and may be incorporated either expressly or by reference. General permit conditions for which the content is mandatory and not subject to site-specific differences (40 CFR Parts 124, 144, 146 and 147) are not discussed in this document. Under 40 CFR §144.35, issuance of this permit does not convey any property rights of any sort or any exclusive privilege, nor does it authorize injury to persons or property or invasion of other private rights, or any infringement of other federal, state or local laws or regulations. EPA UIC permits may be issued for the operating life of the injection well or project unless terminated for reasonable cause under 40 CFR §§144.39, 144.40 and 144.41, and are subject to EPA review at least once every five (5) years to determine if action is required under 40 CFR §144.36(a).

This Permit is issued for the life of the well or wells unless modified, revoked and reissued, or terminated under 40 CFR 144.39 or 144.40. This Permit may be adopted, modified, revoked and reissued, or terminated if primary enforcement authority for this program is delegated to an Indian Tribe or a State. Upon the effective date of delegation, all reports, notifications, questions and other compliance actions shall be directed to the Indian tribe or State Program Director or designee.

Issue Date: DEC 11 2006

Effective Date DEC 11 2006

Carl L Campbell for

Stephen S. Tuber
Assistant Regional Administrator*
Office of Partnerships and Regulatory Assistance

*NOTE: The person holding this title is referred to as the "Director" throughout this Permit.

PART II. SPECIFIC PERMIT CONDITIONS

Section A. WELL CONSTRUCTION REQUIREMENTS

These requirements represent the approved minimum construction standards for well casing and cement, injection tubing, and packer.

Details of the approved well construction plan are incorporated into this Permit as APPENDIX A. Changes to the approved plan that may occur during construction must be approved by the Director prior to being physically incorporated.

1. Casing and Cement.

The well or wells shall be cased and cemented to prevent the movement of fluids into or between underground sources of drinking water. The well casing and cement shall be designed for the life expectancy of the well and of the grade and size shown in APPENDIX A. Remedial cementing may be required if shown to be inadequate by cement bond log or other attempted demonstration of Part II (External) mechanical integrity.

2. Injection Tubing and Packer.

Injection tubing is required, and shall be run and set with a packer at or below the depth indicated in APPENDIX A. The packer setting depth may be changed provided it remains below the depth indicated in APPENDIX A and the Permittee provides notice and obtains the Director's approval for the change.

3. Sampling and Monitoring Devices.

The Permittee shall install and maintain in good operating condition:

(a) a "tap" at a conveniently accessible location on the injection flow line between the pump house or storage tanks and the injection well, isolated by shut-off valves, for collection of representative samples of the injected fluid; and

(b) one-half (1/2) inch female iron pipe fitting, isolated by shut-off valves and located at the wellhead at a conveniently accessible location, for the attachment of a pressure gauge capable of monitoring pressures ranging from normal operating pressures up to the Maximum Allowable Injection Pressure specified in APPENDIX C:

  (i) on the injection tubing; and

  (ii) on the tubing-casing annulus (TCA); and

(c) a pressure actuated shut-off device attached to the injection flow line set to shut-off the injection pump when or before the Maximum Allowable Injection Pressure specified in APPENDIX C is reached at the wellhead; and

(d) a non-resettable cumulative volume recorder attached to the injection line.

4. Well Logging and Testing

Well logging and testing requirements are found in APPENDIX B. The Permittee shall ensure the log and test requirements are performed within the time frames specified in APPENDIX B. Well logs and tests shall be performed according to current EPA-approved procedures. Well log and test results shall be submitted to the Director within sixty (60) days of completion of the logging or testing activity, and shall include a report describing the methods used during logging or testing and an interpretation of the test or log results.

5. Postponement of Construction or Conversion

The Permittee shall complete well construction within one year of the Effective Date of the Permit, or in the case of an Area Permit within one year of authorization of the additional well. Authorization to construct and operate shall expire if the well has not been constructed within one year of the Effective Date of the Permit or authorization and the Permit may be terminated under 40 CFR 144.40, unless the Permittee has notified the Director and requested an extension prior to expiration. Notification shall be in writing, and shall state the reasons for the delay and provide an estimated completion date. Once Authorization has expired under this part, the complete permit process including opportunity for public comment may be required before Authorization to construct and operate may be reissued.

6. Workovers and Alterations

Workovers and alterations shall meet all conditions of the Permit. Prior to beginning any addition or physical alteration to an injection well that may significantly affect the tubing, packer or casing, the Permittee shall give advance notice to the Director and obtain the Director's approval. The Permittee shall record all changes to well construction on a Well Rework Record (EPA Form 7520-12), and shall provide this and any other record of well workover, logging, or test data to EPA within sixty (60) days of completion of the activity.

A successful demonstration of Part I MI is required following the completion of any well workover or alteration which affects the casing, tubing, or packer. Injection operations shall not be resumed until the well has successfully demonstrated mechanical integrity and the Director has provided written approval to resume injection.

Section B. MECHANICAL INTEGRITY

The Permittee is required to ensure each injection well maintains mechanical integrity at all times. The Director, by written notice, may require the Permittee to comply with a schedule describing when mechanical integrity demonstrations shall be made.

An injection well has mechanical integrity if:

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

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

1. Demonstration of Mechanical Integrity (MI).

The operator shall demonstrate MI prior to commencing injection and periodically thereafter. Well-specific conditions dictate the methods and the frequency for demonstrating MI and are discussed in the Statement of Basis. The logs and tests are designed to demonstrate both internal (Part I) and external (Part II) MI as described above. The conditions present at this well site warrant the methods and frequency required in Appendix B of this Permit.

In addition to these regularly scheduled demonstrations of MI, the operator shall demonstrate internal (Part I) MI after any workover which affects the tubing, packer or casing.

The Director may require additional or alternative tests if the results presented by the operator are not satisfactory to the Director to demonstrate there is no movement of fluid into or between USDWs resulting from injection activity. Results of MI tests shall be submitted to the Director as soon as possible but no later than sixty (60) days after the test is complete.

2. Mechanical Integrity Test Methods and Criteria

EPA-approved methods shall be used to demonstrate mechanical integrity. Ground Water Section Guidance No. 34 "Cement Bond Logging Techniques and Interpretation", Ground Water Section Guidance No. 37, "Demonstrating Part II (External) Mechanical Integrity for a Class II injection well permit", and Ground Water Section Guidance No. 39, "Pressure Testing Injection Wells for Part I (Internal) Mechanical Integrity" are available from EPA and will be provided upon request.

The Director may stipulate specific test methods and criteria best suited for a specific well construction and injection operation.

3. Notification Prior to Testing.

The Permittee shall notify the Director at least 30 days prior to any scheduled mechanical integrity test. The Director may allow a shorter notification period if it would be sufficient to enable EPA to witness the mechanical integrity test. Notification may be in the form of a yearly or quarterly schedule of planned mechanical integrity tests, or it may be on an individual basis.

4. Loss of Mechanical Integrity.

If the well fails to demonstrate mechanical integrity during a test, or a loss of mechanical integrity becomes evident during operation (such as presence of pressure in the TCA, water flowing at the surface, etc.), the Permittee shall notify the Director within 24 hours (see Part III Section E Paragraph 11(e) of this Permit) and the well shall be shut-in within 48 hours unless the Director requires immediate shut-in.

Within five days, the Permittee shall submit a follow-up written report that documents test results, repairs undertaken or a proposed remedial action plan.

Injection operations shall not be resumed until after the well has successfully been repaired and demonstrated mechanical integrity, and the Director has provided approval to resume injection.

Section C. WELL OPERATION

INJECTION BETWEEN THE OUTERMOST CASING PROTECTING UNDERGROUND SOURCES OF DRINKING WATER AND THE WELL BORE IS PROHIBITED.

Injection is approved under the following conditions:

1. Requirements Prior to Commencing Injection.

Well injection, including for new wells authorized by an Area Permit under 40 CFR 144.33 (c), may commence only after all well construction and pre-injection requirements herein have been met and approved. The Permittee may not commence injection until construction is complete, and

(a) The Permittee has submitted to the Director a notice of completion of construction and a completed EPA Form 7520-10 or 7520-12; all applicable logging and testing requirements of this Permit (see APPENDIX B) have been fulfilled and the records submitted to the Director; mechanical integrity pursuant to 40 CFR 146.8 and Part II Section B of this Permit has been demonstrated; and

(i) The Director has inspected or otherwise reviewed the new injection well and finds it is in compliance with the conditions of the Permit; or

(ii) The Permittee has not received notice from the Director of his or her intent to inspect or otherwise review the new injection well within 13 days of the date of the notice in Paragraph 1a, in which case prior inspection or review is waived and the Permittee may commence injection.

2. Injection Interval.

Injection is permitted only within the approved injection interval, listed in APPENDIX C. Additional individual injection perforations may be added provided that they remain within the approved injection interval and the Permittee provides notice to the Director in accordance with Part II, Section A, Paragraph 6.

3. Injection Pressure Limitation

(a) The permitted Maximum Allowable Injection Pressure (MAIP), measured at the wellhead, is found in APPENDIX C. Injection pressure shall not exceed the amount the Director determines is appropriate to ensure that injection does not initiate new fractures or propagate existing fractures in the confining zone adjacent to USDWs. In no case shall injection pressure cause the movement of injection or formation fluids into a USDW.

(b) The Permittee may request a change of the MAIP, or the MAIP may be increased or decreased by the Director in order to ensure that the requirements in Paragraph (a) above are fulfilled. The Permitee may be required to conduct a step rate injection test or other suitable test to provide information for determining the fracture pressure of the injection zone. Change of the permitted MAIP by the Director shall be by modification of this Permit and APPENDIX C.

4. Injection Volume Limitation.
Injection volume is limited to the total volume specified in APPENDIX C.

5. Injection Fluid Limitation.
Injected fluids are limited to those identified in 40 CFR 144.6(b)(2) as fluids used for enhanced recovery of oil or natural gas, including those which are brought to the surface in connection with conventional oil or natural gas production that may be commingled with waste waters from gas plants which are an integral part of production operations unless those waters are classified as a hazardous waste at the time of injection, pursuant to 40 CFR 144.6(b). Non-exempt wastes, including unused fracturing fluids or acids, gas plant cooling tower cleaning wastes, service wastes and vacuum truck wastes, are NOT approved for injection. This well is NOT approved for commercial brine injection, industrial waste fluid disposal or injection of hazardous waste as defined by CFR 40 Part 261. The Permittee shall provide a listing of the sources of injected fluids in accordance with the reporting requirements in Part II Section D Paragraph 4 and APPENDIX D of this Permit.

6. Tubing-Casing Annulus (TCA)
The tubing-casing annulus (TCA) shall be filled with water treated with a corrosion inhibitor, or other fluid approved by the Director. The TCA valve shall remain closed during normal operating conditions and the TCA pressure shall be maintained at zero (0) psi.

If TCA pressure cannot be maintained at zero (0) psi, the Permittee shall follow the procedures in Ground Water Section Guidance No. 35 "Procedures to follow when excessive annular pressure is observed on a well."

Section D. MONITORING, RECORDKEEPING, AND REPORTING OF RESULTS

1. Monitoring Parameters, Frequency, Records and Reports.
Monitoring parameters are specified in APPENDIX D. Pressure monitoring recordings shall be taken at the wellhead. The listed parameters are to be monitored, recorded and reported at the frequency indicated in APPENDIX D even during periods when the well is not operating.

Monitoring records must include:

(a) the date, time, exact place and the results of the observation, sampling, measurement, or analysis, and;

(b) the name of the individual(s) who performed the observation, sampling, measurement, or analysis, and;

(c) the analytical techniques or methods used for analysis.

2. Monitoring Methods.

(a) Monitoring observations, measurements, samples, etc. taken for the purpose of complying with these requirements shall be representative of the activity or condition being monitored.

(b) Methods used to monitor the nature of the injected fluids must comply with analytical methods cited and described in Table 1 of 40 CFR 136.3 or Appendix III of 40 CFR 261, or by other methods that have been approved in writing by the Director.

(c) Injection pressure, annulus pressure, injection rate, and cumulative injected volumes shall be observed and recorded at the wellhead under normal operating conditions, and all parameters shall be observed simultaneously to provide a clear depiction of well operation.

(d) Pressures are to be measured in pounds per square inch (psi).

(e) Fluid volumes are to be measured in standard oil field barrels (bbl).

(f) Fluid rates are to be measured in barrels per day (bbl/day).

3. Records Retention.

(a) Records of calibration and maintenance, and all original strip chart recordings for continuous monitoring instrumentation, copies of all reports required by this permit, and records of all data used to complete the application for this permit shall be retained for a period of AT LEAST THREE (3) YEARS from the date of the sample, measurement, report, or application. This period may be extended anytime prior to its expiration by request of the Director.

(b) Records of the nature and composition of all injected fluids must be retained until three (3) years after the completion of any plugging and abandonment (P&A) procedures specified under 40 CFR 144.52(a)(6) or under Part 146 Subpart G, as appropriate. The Director may require the Permittee to deliver the records to the Director at the conclusion of the retention period. The Permittee shall continue to retain the records after the three (3) year retention period unless the Permittee delivers the records to the Director or obtains written approval from the Director to discard the records.

(c) The Permittee shall retain records at the location designated in APPENDIX D.

4. Annual Reports.

Whether the well is operating or not, the Permittee shall submit an Annual Report to the Director that summarizes the results of the monitoring required by Part II Section D and APPENDIX D.

The first Annual Report shall cover the period from the effective date of the Permit through December 31 of that year. Subsequent Annual Reports shall cover the period from January 1 through December 31 of the reporting year. Annual Reports shall be submitted by February 15 of the year following data collection. EPA Form 7520-11 may be copied and shall be used to submit the Annual Report, however, the monitoring requirements specified in this Permit are mandatory even if EPA Form 7520-11 indicates otherwise.

Section E. PLUGGING AND ABANDONMENT

1. Notification of Well Abandonment, Conversion or Closure.

The Permittee shall notify the Director in writing at least forty-five (45) days prior to: 1) plugging and abandoning an injection well, 2) converting to a non-injection well, and 3) in the case of an Area Permit, before closure of the project.

2. Well Plugging Requirements

Prior to abandonment, the injection well shall be plugged with cement in a manner which isolates the injection zone and prevents the movement of fluids into or between underground sources of drinking water, and in accordance with 40 CFR 146.10 and other applicable federal, State or local law or regulations. Tubing, packer and other downhole apparatus shall be removed. Cement with additives such as accelerators and retarders that control or enhance cement properties may be used for plugs; however, volume-extending additives and gel cements are not approved for plug use. Plug placement shall be verified by tagging. Plugging gel of at least 9.6 lb/gal shall be placed between all plugs. A minimum 50 ft surface plug shall be set inside and outside of the surface casing to seal pathways for fluid migration into the subsurface. The Plugging Record must be certified as accurate and complete by the person responsible for the plugging operation. Prior to placement of the cement plug(s) the well shall be in a state of static equilibrium with the mud weight equalized top to bottom, either by circulating the mud in the well at least once or by a comparable method prescribed by the Director.

3. Approved Plugging and Abandonment Plan.

The approved plugging and abandonment plan is incorporated into this Permit as APPENDIX E. Changes to the approved plugging and abandonment plan must be approved by the Director prior to beginning plugging operations. The Director also may require revision of the approved plugging and abandonment plan at any time prior to plugging the well.

4. Forty Five (45) Day Notice of Plugging and Abandonment.

The Permittee shall notify the Director at least forty-five (45) days prior to plugging and abandoning a well and provide notice of any anticipated change to the approved plugging and abanonment plan.

5. Plugging and Abandonment Report.

Within sixty (60) days after plugging a well, the Permittee shall submit a report (EPA Form 7520-13) to the Director. The plugging report shall be certified as accurate by the person who performed the plugging operation. Such report shall consist of either:

(a) A statement that the well was plugged in accordance with the approved plugging and abandonment plan; or

(b) Where actual plugging differed from the approved plugging and abandonment plan, an updated version of the plan, on the form supplied by the Director, specifying the differences.

6. Inactive Wells.

After any period of two years during which there is no injection the Permittee shall plug and abandon the well in accordance with Part II Section E Paragraph 2 of this Permit unless the Permittee:

(a) Provides written notice to the Director;

(b) Describes the actions or procedures the Permittee will take to ensure that the well will not endanger USDWs during the period of inactivity. These actions and procedures shall include compliance with mechanical integrity demonstration, Financial Responsibility and all other permit requirements designed to protect USDWs; and

(c) Receives written notice by the Director temporarily waiving plugging and abandonment requirements.

PART III. CONDITIONS APPLICABLE TO ALL PERMITS

Section A. EFFECT OF PERMIT

The Permittee is allowed to engage in underground injection in accordance with the conditions of this Permit. The Permittee shall not construct, operate, maintain, convert, plug, abandon, or conduct any other activity in a manner that allows the movement of fluid containing any contaminant into underground sources of drinking water, if the presence of that contaminant may cause a violation of any primary drinking water regulation under 40 CFR 142 or may otherwise adversely affect the health of persons. Any underground injection activity not authorized by this Permit or by rule is prohibited. Issuance of this Permit does not convey property rights of any sort or any exclusive privilege; nor does it authorize any injury to persons or property, any invasion of other private rights, or any infringement of State or local law or regulations. Compliance with the terms of this Permit does not constitute a defense to any enforcement action brought under the provisions of Section 1431 of the Safe Drinking Water Act (SDWA) or any other law governing protection of public health or the environment, for any imminent and substantial endangerment to human health or the environment, nor does it serve as a shield to the Permittee's independent obligation to comply with all UIC regulations. Nothing in this Permit relieves the Permittee of any duties under applicable regulations.

Section B. CHANGES TO PERMIT CONDITIONS

1. Modification, Reissuance, or Termination.

The Director may, for cause or upon a request from the Permittee, modify, revoke and reissue, or terminate this Permit in accordance with 40 CFR 124.5, 144.12, 144.39, and 144.40. Also, this Permit is subject to minor modification for causes as specified in 40 CFR 144.41. The filing of a request for modification, revocation and reissuance, termination, or the notification of planned changes or anticipated noncompliance on the part of the Permittee does not stay the applicability or enforceability of any condition of this Permit.

2. Conversions.

The Director may, for cause or upon a written request from the Permittee, allow conversion of the well from a Class II injection well to a non-Class II well. Conversion may not proceed until the Permittee receives written approval from the Director. Conditions of such conversion may include but are not limited to, approval of the proposed well rework, follow up demonstration of mechanical integrity, well-specific monitoring and reporting following the conversion, and demonstration of practical use of the converted configuration.

3. Transfer of Permit.

Under 40 CFR 144.38, this Permit is transferable provided the current Permittee notifies the Director at least thirty (30) days in advance of the proposed transfer date (EPA Form 7520-7) and provides a written agreement between the existing and new Permittees containing a specific date for transfer of Permit responsibility, coverage and liability between them. The notice shall adequately demonstrate that the financial responsibility requirements of 40 CFR 144.52(a)(7) will be met by the new Permittee. The Director may require modification or revocation and reissuance of the Permit to change the name of the Permittee and incorporate such other requirements as may be necessary under the Safe Drinking Water Act; in some cases, modification or revocation and reissuance is mandatory.

4. Permittee Change of Address.

Upon the Permittee's change of address, or whenever the operator changes the address where monitoring records are kept, the Permittee must provide written notice to the Director within 30 days.

5. Construction Changes, Workovers, Logging and Testing Data

The Permittee shall give advance notice to the Director, and shall obtain the Director's written approval prior to any physical alterations or additions to the permitted facility. Alterations or workovers shall meet all conditions as set forth in this permit. The Permittee shall record any changes to the well construction on a Well Rework Record (EPA Form 7520-12), and shall provide this and any other record of well workovers, logging , or test data to EPA within sixty (60) days of completion of the activity.

Following the completion of any well workovers or alterations which affect the casing, tubing, or packer, a successful demonstration of mechanical integrity (Part III, Section F of this permit) shall be made, and written authorization from the Director received, prior to resuming injection activities.

Section C. SEVERABILITY

The Provisions of this Permit are severable, and if any provision of this Permit or the application of any provision of this Permit to any circumstance, is held invalid, the application of such provision to other circumstances, and the remainder of this Permit shall not be affected thereby.

Section D. CONFIDENTIALITY

In accordance with 40 CFR Part 2 and 40 CFR 144.5, information submitted to EPA pursuant to this Permit may be claimed as confidential by the submitter. Any such claim must be asserted at the time of submission by stamping the words "confidential business information" on each page containing such information. If no claim is made at the time of submission, EPA may make the information available to the public without further notice. If a claim is asserted, the validity of the claim will be assessed in accordance with the procedures in 40 CFR Part 2 (Public Information). Claims of confidentiality for the following information will be denied:

- The name and address of the Permittee, and
- information which deals with the existence, absence or level of contaminants in drinking water.

Section E. GENERAL PERMIT REQUIREMENTS

1. Duty to Comply.

The Permittee must comply with all conditions of this Permit. Any noncompliance constitutes a violation of the Safe Drinking Water Act (SDWA) and is grounds for enforcement action; for Permit termination, revocation and reissuance, or modification; or for denial of a permit renewal application; except that the Permittee need not comply with the provisions of this Permit to the extent and for the duration such noncompliance is authorized in an emergency permit under 40 CFR 144.34. All violations of the SDWA may subject the Permittee to penalties and/or criminal prosecution as specified in Section 1423 of the SDWA.

2. *Duty to Reapply.*

If the Permittee wishes to continue an activity regulated by this Permit after the expiration date of this Permit, under 40 CFR 144.37 the Permittee must apply for a new permit prior to the expiration date.

3. *Need to Halt or Reduce Activity Not a Defense.*

It shall not be a defense for a Permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this Permit.

4. *Duty to Mitigate.*

The Permittee shall take all reasonable steps to minimize or correct any adverse impact on the environment resulting from noncompliance with this Permit.

5. *Proper Operation and Maintenance.*

The Permittee shall at all times properly operate and maintain all facilities and systems of treatment and control (and related appurtenances) which are installed or used by the Permittee to achieve compliance with the conditions of this Permit. Proper operation and maintenance includes effective performance, adequate funding, adequate operator staffing and training, and adequate laboratory and process controls, including appropriate quality assurance procedures. This provision requires the operation of back-up or auxiliary facilities or similar systems only when necessary to achieve compliance with the conditions of this Permit.

6. *Permit Actions.*

This Permit may be modified, revoked and reissued or teminated for cause. The filing of a request by the Permittee for a permit modification, revocation and reissuance, or termination, or a notification of planned changes or anticipated noncompliance, does not stay any permit condition.

7. *Property Rights.*

This Permit does not convey any property rights of any sort, or any exclusive privilege.

8. *Duty to Provide Information.*

The Permittee shall furnish to the Director, within a time specified, any information which the Director may request to determine whether cause exists for modifying, revoking and reissuing, or terminating this permit, or to determine compliance with this permit. The Permittee shall also furnish to the Director, upon request, copies of records required to be kept by this Permit. The Permittee is required to submit any information required by this Permit or by the Director to the mailing address designated in writing by the Director.

9. *Inspection and Entry.*

The Permittee shall allow the Director, or an authorized representative, upon the presentation of credentials and other documents as may be required by law, to:

(a) Enter upon the Permittee's premises where a regulated facility or activity is located or conducted, or where records must be kept under the conditions of this Permit;

(b) Have access to and copy, at reasonable times, any records that must be kept under the conditions of this Permit;

(c) Inspect at reasonable times any facilities, equipment (including monitoring and control equipment), practices, or operations regulated or required under this Permit; and,

(d) Sample or monitor at reasonable times, for the purpose of assuring permit compliance or as otherwise authorized by the SDWA, any substances or parameters at any location.

10. Signatory Requirements.
All applications, reports or other information submitted to the Director shall be signed and certified according to 40 CFR 144.32. This section explains the requirements for persons duly authorized to sign documents, and provides wording for required certification.

11. Reporting Requirements.

(a) Planned changes. The Permittee shall give notice to the Director as soon as possible of any planned changes, physical alterations or additions to the permitted facility, and prior to commencing such changes.

(b) Anticipated noncompliance. The Permittee shall give advance notice to the Director of any planned changes in the permitted facility or activity which may result in noncompliance with permit requirements.

(c) Monitoring Reports. Monitoring results shall be reported at the intervals specified in this Permit.

(d) Compliance schedules. Reports of compliance or noncompliance with, or any progress reports on, interim and final requirements contained in any compliance schedule of this Permit shall be submitted no later than 30 days following each schedule date.

(e) Twenty-four hour reporting. The Permittee shall report to the Director any noncompliance which may endanger human health or the environment, including:

   (i) Any monitoring or other information which indicates that any contaminant may cause endangerment to a USDW; or

   (ii) Any noncompliance with a permit condition or malfunction of the injection system which may cause fluid migration into or between USDWs.

Information shall be provided, either directly or by leaving a message, within twenty-four (24) hours from the time the permittee becomes aware of the circumstances by telephoning (800) 227-8917 and requesting EPA Region VIII UIC Program Compliance and Technical Enforcement Director, or by contacting the EPA Region VIII Emergency Operations Center at (303) 293-1788.

In addition, a follow up written report shall be provided to the Director within five (5) days of the time the Permittee becomes aware of the circumstances. The written submission shall contain a description of the noncompliance and its cause, the period of noncompliance including exact dates and times, and if the noncompliance has not been corrected the anticipated time it is expected to continue; and the steps taken or planned to reduce, eliminate, and prevent recurrence of the noncompliance.

(f) Oil Spill and Chemical Release Reporting: The Permittee shall comply with all reporting requirements related to the occurence of oil spills and chemical releases by contacting the National Response Center (NRC) at (800) 424-8802, (202) 267-2675, or through the NRC website http://www.nrc.uscg.mil/index.htm.

(g) Other Noncompliance. The Permittee shall report all instances of noncompliance not reported under paragraphs Part III, Section E Paragraph 11(b) or Section E, Paragraph 11(e) at the time the monitoring reports are submitted. The reports shall contain the information listed in Paragraph 11(e) of this Section.

(h) Other information. Where the Permittee becomes aware that it failed to submit any relevant facts in the permit application, or submitted incorrect information in a permit application or in any report to the Director, the Permittee shall promptly submit such facts or information to the Director.

Section F. FINANCIAL RESPONSIBILITY

1. Method of Providing Financial Responsibility.

The Permittee shall maintain continuous compliance with the requirement to maintain financial responsibility and resources to close, plug, and abandon the underground injection well(s). No substitution of a demonstration of financial responsibility shall become effective until the Permittee receives written notification from the Director that the alternative demonstration of financial responsibility is acceptable. The Director may, on a periodic basis, require the holder of a permit to revise the estimate of the resources needed to plug and abandon the well to reflect changes in such costs and may require the Permittee to provide a revised demonstration of financial responsibility.

2. Insolvency.

In the event of:

(a) the bankruptcy of the trustee or issuing institution of the financial mechanism; or

(b) suspension or revocation of the authority of the trustee institution to act as trustee; or

(c) the institution issuing the financial mechanism losing its authority to issue such an instrument

the Permittee must notify the Director in writing, within ten (10) business days, and the Permittee must establish other financial assurance or liability coverage acceptable to the Director within sixty (60) days after any event specified in (a), (b), or (c) above.

The Permittee must also notify the Director by certified mail of the commencement of voluntary or involuntary proceedings under Title 11 (Bankruptcy), U.S. Code naming the owner or operator as debtor, within ten (10) business days after the commencement of the proceeding. A guarantor, if named as debtor of a corporate guarantee, must make such a notification as required under the terms of the guarantee.

APPENDIX A

WELL CONSTRUCTION REQUIREMENTS

See Schematic:

The Blackjack Federal No. 10-5-9-17 was drilled to total depth of 6015 feet (KB) in the Basal Carbonate Member of the Green River Formation.

Surface casing (8-5/8 inch) was set at a depth of 333 feet in a 12-1/4 inch hole using 160 sacks of Class "G" cement which was circulated to the surface.

Production casing (5-1/2 inch) was set at a depth of 5985 feet (KB) in a 7-7/8 inch hole with 350 sacks of Premium Lite II and 400 sacks of 50/50 Pozmix. Well construction is considered adequate to protect all USDWs.

The EPA calculates top of cement (TOC) at 1154 feet from the surface.

The Schematic Diagram shows the proposed-current injection perforations in the Garden Gulch and Douglas Creek Members of the Green River Formation. Additional perforations may be added at a later time between the depths of 3673 feet and the top of the Wasatch Formation (Estimated to be 6062 feet) provided that the operator first notifies the Director and later submits an updated Well Rework Record (EPA Form 7520-12) and schematic diagram.

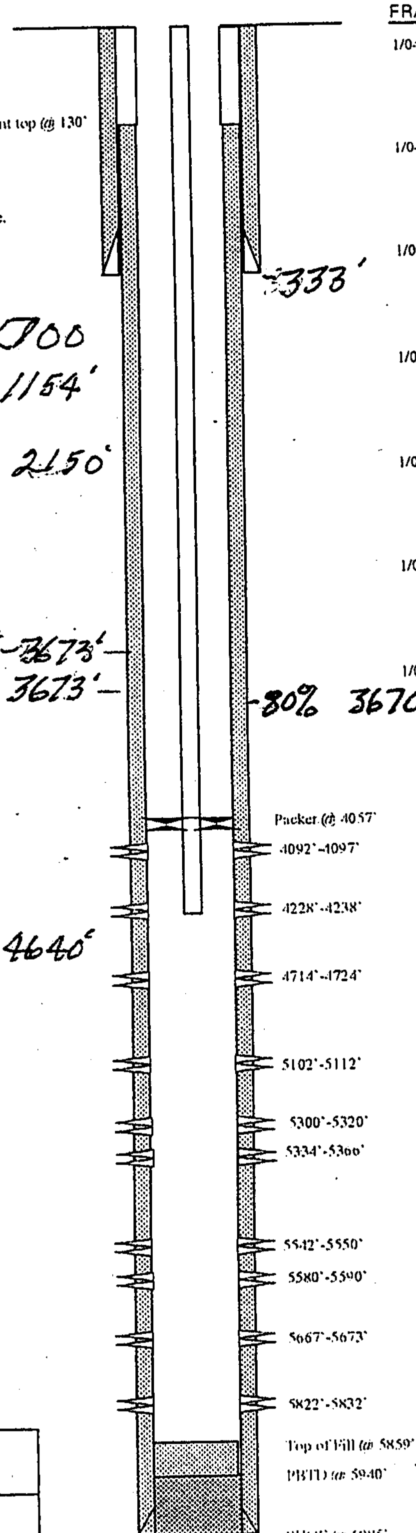
The packer will be set no higher than 100 feet above the top perforation.

Blackjack Federal 10-5-9-17

Spud Date: 12/1/04
Put on Production: 1/11/05
GL: 5251' KB: 5263'

Proposed Injection
Wellbore Diagram

Initial Production: BOPD,
MCFD, BWPD



SURFACE CASING

CSG SIZE: 8-5/8"
GRADE: J-55
WEIGHT: 24#
LENGTH: 8 jts (323.05')
DEPTH LANDED: 333.05'
HOLE SIZE: 12-1/4"
CEMENT DATA: 160 sxs Class G cement. Est 4 bbls cmt to surface.

Base USDWs 700

PRODUCTION CASING TOC/EPA 1154'

CSG SIZE: 5-1/2"
GRADE: J-55
WEIGHT: 15.5# Green River 2150'
LENGTH: 142 jts. (5988.91')
DEPTH LANDED: 5985.35' KB
HOLE SIZE: 7-7/8"
CEMENT DATA: 350 sxs Premlite II & 400 sxs 50/50 POZ.
CEMENT TOP AT: 130'

Confining Zone 3620'-3673'
Garden Gulch 3673' -80% 3670-3868'

TUBING

SIZE/GRADE/WT.: 2-7/8" / J-55 / 6.5#
NO. OF JOINTS: 169 jts (5641.19')
TUBING ANCHOR: 5653.19' KB
NO. OF JOINTS: 1 jt (33.39')
SEATING NIPPLE: 2-7/8" (1.10')
SN LANDED AT: 5689.38' KB
NO. OF JOINTS: 2 jts (66.70')
TOTAL STRING LENGTH: EOT @ 5757.63' w/ 12' KB

Douglas Cr. 4640'

FRAC JOB

1/04/05	5822'-5832'	**Frac CP5 sands as follows:** 18,712# 20/40 sand in 268 bbls Lightning 17 frac fluid. Treated @ avg press of 2130 psi w/avg rate of 24.5 BPM. ISIP 2145 psi. Calc. flush: 5820 gal. Actual flush: 5859 gal.
1/04/05	5542'-5673'	**Frac CP3, 1 & .5 sands as follows:** 64,105# 20/40 sand in 524 bbls Lightning 17 frac fluid. Treated @ avg press of 1956 psi w/avg rate of 24.5 BPM. ISIP 1990 psi. Calc. flush: 5540 gal. Actual flush: 5573 gal.
1/04/05	5300'-5366'	**Frac LODC sands as follows:** 199,147# 20/40 sand in 1337 bbls Lightning 17 frac fluid. Treated @ avg press of 1684 psi w/avg rate of 24.5 BPM. ISIP 2100 psi. Calc. flush: 5298 gal. Actual flush: 5330 gal.
1/04/05	5102'-5112'	**Frac A3 sands as follows:** 44,330# 20/40 sand in 411 bbls Lightning 17 frac fluid. Treated @ avg press of 1968 psi w/avg rate of 24.5 BPM. ISIP 2300 psi. Calc. flush: 5100 gal. Actual flush: 5124 gal.
1/05/05	4714'-4724'	**Frac D2 sands as follows:** 19,177# 20/40 sand in 241 bbls Lightning 17 frac fluid. Treated @ avg press of 1791 psi w/avg rate of 24.3 BPM. ISIP 1850 psi. Calc. flush: 4712 gal. Actual flush: 4725 gal.
1/05/05	4228'-4238'	**Frac GB6 sands as follows:** 63,938# 20/40 sand in 493 bbls Lightning 17 frac fluid. Treated @ avg press of 2267 psi w/avg rate of 24.5 BPM. ISIP 1780 psi. Calc. flush: 4226 gal. Actual flush: 4259 gal.
1/05/05	4092'-4097'	**Frac GB2 sands as follows:** 14,210# 20/40 sand in 230 bbls Lightning 17 frac fluid. Treated @ avg press of 2447 psi w/avg rate of 24.6 BPM. ISIP 1970 psi. Calc flush: 4090 gal. Actual flush: 4003 gal.

PERFORATION RECORD

12/30/04	5822'-5832'	4 JSPF	40 holes
01/04/05	5667'-5673'	4 JSPF	24 holes
01/04/05	5580'-5590'	4 JSPF	40 holes
01/04/05	5542'-5550'	4 JSPF	32 holes
01/04/05	5334'-5366'	2 JSPF	64 holes
01/04/05	5300'-5320'	2 JSPF	40 holes
01/04/05	5102'-5112'	4 JSPF	40 holes
01/04/05	4714'-4724'	4 JSPF	40 holes
01/05/05	4228'-4238'	4 JSPF	40 holes
01/05/05	4092'-4097'	4 JSPF	20 holes

5937' Basal Carbonate

6062' Est. Wasatch

NEWFIELD

Blackjack Federal #10-5-9-17

1676' FSL & 1982' FEL

NWSE Section 5-T9S-R17E

Duchesne Co, Utah

API #43-013-32553; Lease #UTU-74808

MC 1/18/05

APPENDIX B

LOGGING AND TESTING REQUIREMENTS

Logs.
Logs will be conducted according to current UIC guidance. It is the responsibility of the permittee to obtain and use guidance prior to conducting any well logging required as a condition of this permit.

NO LOGGING REQUIREMENTS

Tests.
Tests will be conducted according to current UIC guidance. It is the responsibility of the permittee to obtain and use guidance prior to conducting any well test required as a condition of this permit.

WELL NAME: Blackjack Federal 10-5-9-17

TYPE OF TEST	DATE DUE
Step Rate Test	Within 180 days following commencement of injection.
Radioactive Tracer Survey (2)	Within 180 days following commencement of injection and at least once every five (5) years thereafter.
Standard Annulus Pressure	Prior to authorization to inject and at least once every five (5) years thereafter.
Pore Pressure	Prior to authorization to inject.

APPENDIX C

OPERATING REQUIREMENTS

MAXIMUM ALLOWABLE INJECTION PRESSURE:

Maximum Allowable Injection Pressure (MAIP) as measured at the surface shall not exceed the pressure(s) listed below.

WELL NAME	MAXIMUM ALLOWED INJECTION PRESSURE (psi) ZONE 1 (Upper)
Blackjack Federal 10-5-9-17	1,450

INJECTION INTERVAL(S):

Injection is permitted only within the approved injection interval listed below. Injection perforations may be altered provided they remain within the approved injection interval and the Permittee provides notice to the Director in accordance with Part II, Section A, Paragraph 6. Specific injection perforations can be found in Appendix A.

WELL NAME: Blackjack Federal 10-5-9-17

FORMATION NAME	APPROVED INJECTION INTERVAL (KB, ft) TOP	BOTTOM	FRACTURE GRADIENT (psi/ft)
Green River	3,673.00 -	6,062.00	0.790

ANNULUS PRESSURE:

The annulus pressure shall be maintained at zero (0) psi as measured at the wellhead. If this pressure cannot be maintained, the Permittee shall follow the procedures listed under Part II, Section C. 6. of this permit.

MAXIMUM INJECTION VOLUME:

There is no limitation on the number of barrels per day (bbls/day) of water that shall be injected into this well, provided further that in no case shall injection pressure exceed that limit shown in Appendix C.

APPENDIX D

MONITORING AND REPORTING PARAMETERS

This is a listing of the parameters required to be observed, recorded, and reported. Refer to the permit Part II, Section D, for detailed requirements for observing, recording, and reporting these parameters.

OBSERVE MONTHLY AND RECORD AT LEAST ONCE EVERY THIRTY DAYS	
OBSERVE AND RECORD	Injection pressure (psig)
	Annulus pressure(s) (psig)
	Injection rate (bbl/day)
	Fluid volume injected since the well began injecting (bbls)

ANNUALLY	
ANALYZE	Injected fluid total dissolved solids (mg/l)
	Injected fluid specific gravity
	Injected fluid specific conductivity
	Injected fluid pH

ANNUALLY	
REPORT	Each month's maximum and averaged injection pressures (psig)
	Each month's maximum and averaged annulus pressure(s) (psig)
	Each month's averaged injection rate (bbl/day)
	Fluid volume injected since the well began injecting (bbl)
	Written results of annual injected fluid analysis
	Sources of all fluids injected during the year

Records of all monitoring activities must be retained and made available for inspection at the following location:

APPENDIX E

PLUGGING AND ABANDONMENT REQUIREMENTS

See Schematic Diagram:

All cement plugs will be set with tubing.

9.2 ppg plugging gel, or fresh water weighted with bentonite or treated brine will be placed between all plugs.

The following Plugging and Abandonment Plan (P&A Plan), as proposed by the applicant, is predicated on the permittee not revising the current-proposed injection perforations as cited on the schematic diagram of well conversion. Should the uppermost perforations (4092 feet - 4097 feet) be modified in conversion, the EPA will modify the P&A Plan accordingly.

Plug No. 3 has been revised from the Draft Permit to extend Plug No. 3 from a total depth of 383 feet to 750 feet. Plug No. 3 in the Draft Permit did not consider the base of the USDWs to be at a depth from surface of 700 feet.

PLUG NO. 1: Set a cast iron bridge plug (CIBP) at 3997 feet with 100 sacks of Class "G" cement on top of CIBP.

PLUG NO. 2: Set a Class "G" cement plug frpm 2000 feet - 2200 feet as requested by the Bureau of Land Management (BLM). This plug will also cover the top of the Green River Formation as required by the BLM.

PLUG NO. 3: Set a cement plug within the 5-1/2 inch casing to a depth of 750 feet. Plug No. 3 will also include a cement plug within the 5-1/2 inch X 8-5/8 inch casing annulus and the 5-1/2 inch X 7-7/8 inch annulus from the surface to a depth of 750 feet.

Attachment Q-2

Blackjack Federal 10-5-9-17

Spud Date: 12/1/04
Put on Production: 1/11/05
GL: 5251' KB: 5263'

Initial Production: BOPD, MCFD, BWPD

Proposed P & A
Wellbore Diagram

SURFACE CASING

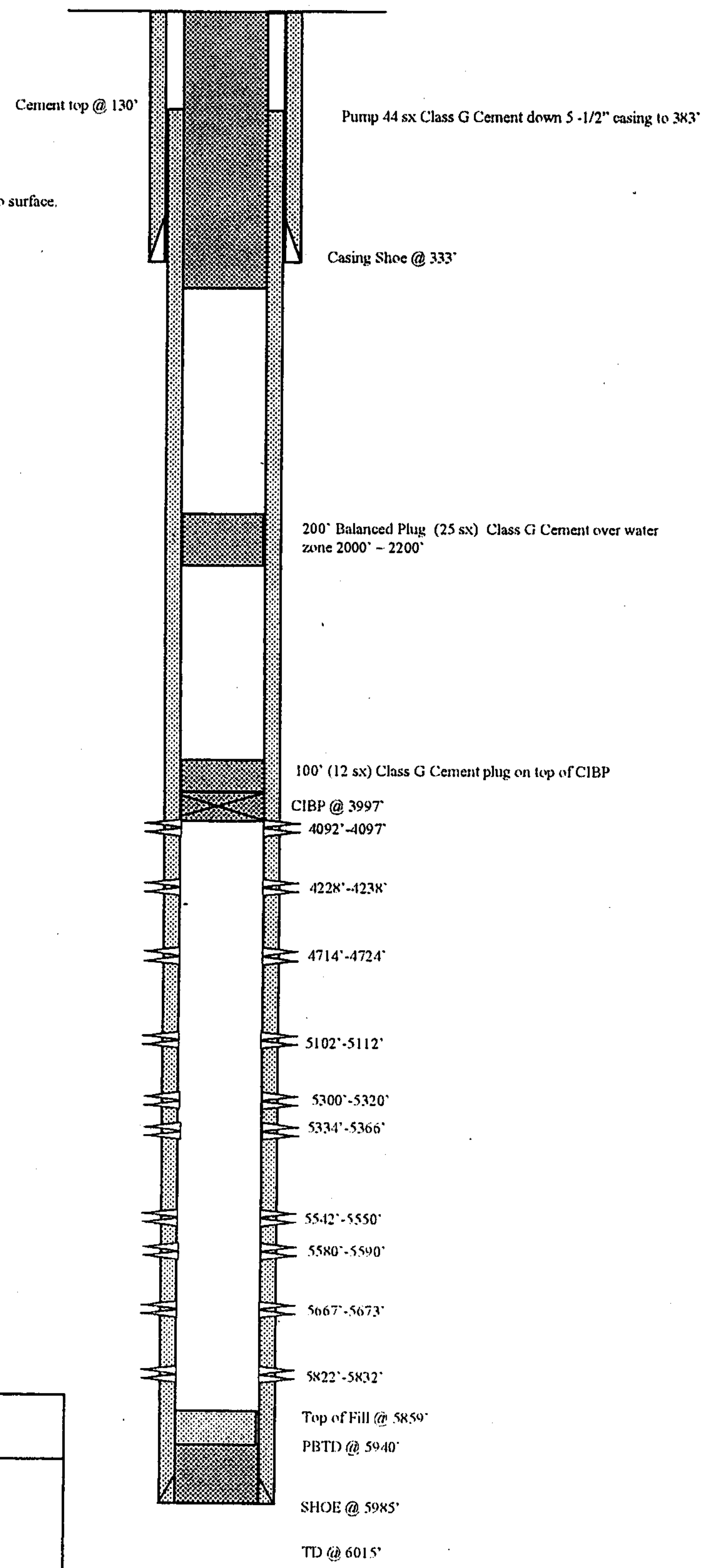
CSG SIZE: 8-5/8"
GRADE: J-55
WEIGHT: 24#
LENGTH: 8 jts (323.05')
DEPTH LANDED: 333.05'
HOLE SIZE: 12-1/4"
CEMENT DATA: 160 sxs Class G cement. Est 4 bbls cmt to surface.

PRODUCTION CASING

CSG SIZE: 5-1/2"
GRADE: J-55
WEIGHT: 15.5#
LENGTH: 142 jts. (5988.91')
DEPTH LANDED: 5985.35' KB
HOLE SIZE: 7-7/8"
CEMENT DATA: 350 sxs Premlite II & 400 sxs 50/50 POZ.
CEMENT TOP AT: 130'

TUBING

SIZE/GRADE/WT.: 2-7/8" / J-55 / 6.5#
NO. OF JOINTS: 169 jts (5641.19')
TUBING ANCHOR: 5653.19' KB
NO. OF JOINTS: 1 jt (33.39')
SEATING NIPPLE: 2-7/8" (1.10')
SN LANDED AT: 5689.38' KB
NO. OF JOINTS: 2 jts (66.70')
TOTAL STRING LENGTH: EOT @ 5757.63' w/ 12' KB



NEWFIELD

Blackjack Federal #10-5-9-17

1676' FSL & 1982' FEL

NWSE Section 5-T9S-R17E

Duchesne Co. Utah

API #43-013-32553; Lease #UTU-74808

MC 4/18/05

APPENDIX F

CORRECTIVE ACTION REQUIREMENTS

No corrective action required.

STATEMENT OF BASIS

NEWFIELD PRODUCTION COMPANY
BLACKJACK FEDERAL 10-5-9-17
DUCHESNE COUNTY, UT

EPA PERMIT NO. UT20998-06753

CONTACT: Emmett Schmitz
U. S. Environmental Protection Agency
Ground Water Program, 8P-W-GW
999 18th Street, Suite 300
Denver, Colorado 80202-2466
Telephone: 1-800-227-8917 ext. 6174

This STATEMENT OF BASIS gives the derivation of site-specific UIC Permit conditions and reasons for them. Referenced sections and conditions correspond to sections and conditions in the Permit.

EPA UIC permits regulate the injection of fluids into underground injection wells so that the injection does not endanger underground sources of drinking water. EPA UIC permit conditions are based upon the authorities set forth in regulatory provisions at 40 CFR Parts 144 and 146, and address potential impacts to underground sources of drinking water. Under 40 CFR 144.35 Issuance of this permit does not convey any property rights of any sort or any exclusive privilege, nor authorize injury to persons or property of invasion of other private rights, or any infringement of other federal, state or local laws or regulations. Under 40 CFR 144 Subpart D, certain conditions apply to all UIC Permits and may be incorporated either expressly or by reference. General Permit conditions for which the content is mandatory and not subject to site-specific differences (40 CFR Parts 144, 146 and 147) are not discussed in this document.

PART I. General Information and Description of Facility

Newfield Production Company
1401 Seventeenth Street
Suite 1000
Denver, CO 80202

on

April 26, 2005

submitted an application for an Underground Injection Control (UIC) Program Permit or Permit Modification for the following injection well or wells:

Blackjack Federal 10-5-9-17
1676' FSL & 1982' FEL, NWSE S5, T9S, R17E
DUCHESNE County, UT

Regulations specific to Uintah-Ouray Indian Reservation injection wells are found at 40 CFR 147 Subpart TT.

The application, including the required information and data necessary to issue or modify a UIC Permit in accordance with 40 CFR Parts 144, 146 and 147, was reviewed and determined by EPA to be complete.

The Permit will expire upon delegation of primary enforcement responsibility (primacy) for applicable portions of the UIC Program to the Ute Indian Tribe or the State of Utah unless the delegated agency has the authority and chooses to adopt and enforce this Permit as a Tribal or State Permit.

TABLE 1.1 shows the status of the well or wells as "New", "Existing", or "Conversion" and for Existing shows the original date of injection operation. Well authorization "by rule" under 40 CFR Part 144 Subpart C expires automatically on the Effective Date of an issued UIC Permit.

The Blackjack Federal No. 10-5-9-17 is currently an active Garden Gulch-Douglas Creek Members of the Green River Formation oil well. The applicant intends to convert this oil well to an enhanced recovery injection facility.

TABLE 1.1

WELL STATUS / DATE OF OPERATION

CONVERSION WELLS		
Well Name	**Well Status**	**Date of Operation**
Blackjack Federal 10-5-9-17	Conversion	N/A

PART II. Permit Considerations (40 CFR 146.24)

The proposed injection well is located in the Newfield Production Company Greater Monument Butte area near the center of the broad, gently northward dipping south flank of the Uinta Basin. The beds dip at about 200'/mile, and there are no known surface folds or faults in the field. The lower 600' to 800'of the Uinta Formation, generally consisting of 5' to 20' thick brown lenticular fluvial sandstone and interbedded varicolored shales, outcrops at the surface in this area. The Uinta is underlain by the Green River Formation which consists of lake (lacustrine) margin sandstones, limestone and shale beds that were deposited along the edges and on the broad level floor of Lake Uinta as it expanded and contracted through time. Underlying the Green River Formation is the Wasatch Formation, which is approximately 2400' thick in this area and consists of red alluvial shales and siltstone with scattered lenticular sandstones usually 10' to 50' thick. Below the Wasatch Formation is the Mesaverde Formation; a series of interbedded continental deposits of shale, sandstone, and coal. Water samples from Mesaverde sands in the nearby Natural Buttes Unit yield highly saline water.

The Uinta Basin is a topographic and structural trough encompassing an area of more than 9300 square mi (14,900 km) in northeast Utah. The basin is sharply asymmetrical, with a steep north flank bounded by the east-west-trending Uinta Mountains, and a gently dipping south flank. The Uinta Basin formed in Paleocene to Eocene time, creating a large area of internal drainage which was filled by ancestral Lake Uinta. Deposition in and around Lake Uinta consisted of open- to marginal-lacustrine sediments that make up the Green River Formation. Alluvial red-bed deposits that are laterally equivalent to and intertongue with the Green River make up the Colton Formation (Wasatch). More than 450 million barrels of oil (63 MT) have been produced from the Green River and Wasatch Formations in the Uinta Basin. The southern shore of Lake Uinta was very broad and flat, which allowed large transgressive and regressive shifts in the shoreline in response to climatic and tectonic-induced rise and fall of the lake. The cyclic nature of Green River deposition in the southern shore area resulted in numerous stacked deltaic deposits. Distributary-mouth bars, distributary channels, and near-shore bars are the primary producing sandstone reservoirs in the area (Ref: "Reservoir Characterization of the Lower Green River Formation, Southwest Uinta Basin, Utah Biannual Technical Progress Report 4/1/99 - 9/30/99", by C. D. Morgan, Program Manager, November 1999, Contract DE-AC26-98BC15103). The Tertiary Duchesne River Formation alluvium generally is present at the surface in this area.

Throughout the current Newfield Production Company area of enhanced recovery injection activity, i.e., T8-9S - R15-19E, Green River Formation water analyses generally exhibit total dissolved (TDS) content well in excess of 10,000 mg/l. A few recent applications for well conversion to enhanced recovery injection contain Green River water analyses withTDS approximating 10,000 mg/l. The State of Utah-Natural Resources ascribes low TDS values to several possibilities involving dilution of Green River water with high TDS values, e,g., recharge of the Green River Formation via Green River Formation outcrop on the Book Cliffs/Roan Cliffs; injection of very low TDS Johnson Water District Reservoir source water; and percolation of surface water via deep-seated Gilsonite veins penetrating lower Green River Members.

Geologic Setting (TABLE 2.1)

TABLE 2.1
GEOLOGIC SETTING
Blackjack Federal 10-5-9-17

Formation Name	Top (ft)	Base (ft)	TDS (mg/l)	Lithology
Uinta	0.00	2,150.00	< 10,000.00	Sand and shale
Green River	2,150.00	6,062.00	19,369.00	Predominantly lacustrine carbonate, sand and shale interbedded with fluviatile sand and shale.

Proposed Injection Zone(s) (TABLE 2.2)
An injection zone is a geological formation, group of formations, or part of a formation that receives fluids through a well. The proposed injection zones are listed in TABLE 2.2.

Injection will occur into an injection zone that is separated from USDWs by a confining zone which is free of known open faults or fractures within the Area of Review.

The approved interval for enhanced recovery injection is located between the top of the Garden Gulch Member (3673 feet) and the top of the Wasatch Formation which has an estimated top of 6062 feet.

TABLE 2.2
INJECTION ZONES
Blackjack Federal 10-5-9-17

Formation Name	Top (ft)	Base (ft)	TDS (mg/l)	Fracture Gradient (psi/ft)	Porosity	Exempted?*
Green River	3,673.00	6,062.00	19,369.00	0.790		N/A

*** C - Currently Exempted**
E - Previously Exempted
P - Proposed Exemption
N/A - Not Applicable

Confining Zone(s) (TABLE 2.3)
A confining zone is a geological formation, part of a formation, or a group of formations that limits fluid movement above the injection zone. The confining zone or zones are listed in TABLE 2.3.

The 53-foot (3620 feet - 3673 feet) shale confining zone directly overlies the top of the Garden Gulch Member.

TABLE 2.3
CONFINING ZONES
Blackjack Federal 10-5-9-17

Formation Name	Formation Lithology	Top (ft)	Base (ft)
Green River	Shale	3,620.00	3,673.00

Underground Sources of Drinking Water (USDWs) (TABLE 2.4)

Aquifers or the portions thereof which contain less than 10,000 mg/l total dissolved solids (TDS) and are being or could in the future be used as a source of drinking water are considered to be USDWs. The USDWs in the area of this facility are identified in TABLE 2.4.

The State of Utah "Water Wells and Springs", http//NRWRT1.STATE.UT.US, identifies no public water supply wells within the one-quarter (1/4) mile Area-of-Review (AOR) around the Blackjack Federal No. 10-5-9-17.

Technical Publication No. 92: State of Utah, Department of Natural Resources, cites the base of Underground Sources of Drinking Water (USDW) in the Uinta Formation, approximately 700 feet from the surface.

TABLE 2.4
UNDERGROUND SOURCES OF DRINKING WATER (USDW)
Blackjack Federal 10-5-9-17

Formation Name	Formation Lithology	Top (ft)	Base (ft)	TDS (mg/l)
Uinta	Sand and shale	0.00	700.00	< 10,000.00

PART III. Well Construction (40 CFR 146.22)

All cement plugs will be set with tubing.

9.2 ppg plugging gel, or fresh water weighted with bentonite or treated brine will be placed between all plugs.

The following Plugging amnd Abandonment Plan (P&A Plan), as proposed by the applicant, is predicated on the permittee not revising the current-proposed injection perforations as cited on the schematic diagram of well conversion. Should the uppermost perforations (4092 feet - 4097 feet) be modified in conversion, the EPA will modify the P&A Plan accordingly.

PLUG NO. 1: Set a cast iron bridge plug (CIBP) at 3997 feet with 100 sacks of Class "G" cement on top of CIBP.

PLUG NO. 2: Set a Class "G" cement plug frpm 2000 feet - 2200 feet as requested by the Bureau of Land Management (BLM). This plug will also cover the top of the Green River Formation as required by the BLM.

PLUG NO. 3: Set a cement plug within the 5-1/2 inch casing and a cement plug within the 5-1/2 inch X 8-5/8 inch casing annulus from the surface to a depth of 383 feet.

TABLE 3.1
WELL CONSTRUCTION REQUIREMENTS
Blackjack Federal 10-5-9-17

Casing Type	Hole Size (in)	Casing Size (in)	Cased Interval (ft)	Cemented Interval (ft)
Production	7.88	5.50	0.00 - 5,985.00	1,154.00 - 5,988.00
Surface	12.25	8.63	0.00 - 333.00	0.00 - 333.00

The approved well completion plan will be incorporated into the Permit as APPENDIX A and will be binding on the Permittee. Modification of the approved plan is allowed under 40 CFR 144.52(a)(1) provided written approval is obtained from the Director prior to actual modification.

Casing and Cementing (TABLE 3.1)

The construction plan for the well or wells proposed for conversion to an injection well was evaluated and determined to be in conformance with standard practices and guidelines that ensure well injection does not result in the movement of fluids into USDWs. Well construction and conversion details for the well or wells are shown in TABLE 3.1.

Tubing and Packer

Injection tubing is required to be installed from a packer up to the surface inside the well casing. The packer will be set above the uppermost perforation. The tubing and packer are designed to prevent injection fluid from coming into contact with the outermost casing.

Tubing-Casing Annulus (TCA)

The TCA allows the casing, tubing and packer to be pressure-tested periodically for mechanical integrity, and will allow for detection of leaks. The TCA will be filled with fresh water treated with a corrosion inhibitor or other fluid approved by the Director.

The tubing/casing annulus must be kept closed at all times so that it can be monitored as required under the Permit.

Monitoring Devices
The permittee will be required to install and maintain wellhead equipment that allows for monitoring pressures and providing access for sampling the injected fluid. Required equipment may include but is not limited to: 1) shut-off valves located at the wellhead on the injection tubing and on the TCA; 2) a flow meter that measures the cumulative volume of injected fluid; 3) fittings or pressure gauges attached to the injection tubing and the TCA for monitoring the injection and TCA pressure; and 4) a tap on the injection line, isolated by shut-off valves, for sampling the injected fluid.

All sampling and measurement taken for monitoring must be representative of the monitored activity.

PART IV. Area of Review, Corrective Action Plan (40 CFR 144.55)

TABLE 4.1
AOR AND CORRECTIVE ACTION

Well Name	Type	Status (Abandoned Y/N)	Total Depth (ft)	TOC Depth (ft)	CAP Required (Y/N)
Allen Federal 43-5	Other	Yes	5,890.00	5,889.00	No
Allen Federal 44-5	Injector	No	5,954.00	2,164.00	No
Balcron Monument Fed. 23-5J-9-17	Producer	No	5,773.00	3,100.00	No
Blackjack 9-5R-9-17	Producer	No	5,890.00	1,029.00	No
Blackjack Federal 7-5-9-17	Producer	No	6,050.00	1,573.00	No
Federal 43-5H-9-17	Producer	No	6,067.00	940.00	No
Monument Federal 24-5-9-17	Injector	No	5,700.00	1,645.00	No

TABLE 4.1 lists the wells in the Area of Review ("AOR") and shows the well type, operating status, depth, top of casing cement ("TOC") and whether a Corrective Action Plan ("CAP") is required for the well.

Area Of Review
Applicants for Class I, II (other than "existing" wells) or III injection well Permits are required to identify the location of all known wells within the injection well's Area of Review (AOR) which penetrate the injection zone, or in the case of Class II wells operating over the fracture pressure of the formation, all known wells within the area of review that penetrate formations which may be affected by increased pressure. Under 40 CFR 146.6 the AOR may be a fixed radius of not less than one quarter (1/4) mile or a calculated zone of endangering influence. For Area Permits, a

fixed width of not less than one quarter (1/4) mile for the circumscribing area may be used.

Corrective Action Plan

For wells in the AOR which are improperly sealed, completed, or abandoned, the applicant shall develop a Corrective Action Plan (CAP) consisting of the steps or modifications that are necessary to prevent movement of fluid into USDWs.

The CAP will be incorporated into the Permit as APPENDIX F and become binding on the permittee.

TABLE 4.1 lists the wells in the AOR, and shows the well type, operating status, depth, top of casing cement and whether a CAP is required for this well.

PART V. Well Operation Requirements (40 CFR 146.23)

TABLE 5.1
INJECTION ZONE PRESSURES
Blackjack Federal 10-5-9-17

Formation Name	Depth Used to Calculate MAIP (ft)	Fracture Gradient (psi/ft)	Initial MAIP (psi)
Green River	4,092.00	0.790	1,450

Approved Injection Fluid

The approved injection fluid is limited to Class II injection well fluids pursuant to 40 CFR § 144.6(b). For disposal wells injecting water brought to the surface in connection with natural gas storage operations, or conventional oil or natural gas production, the fluid may be commingled and the well used to inject other Class II wastes such as drilling fluids and spent well completion, treatment and stimulation fluid. Injection of non-exempt wastes, including unused fracturing fluids or acids, gas plant cooling tower cleaning wastes, service wastes and vacuum truck wastes, is prohibited.

The proposed injectate is primarily fluid from the Johnson Water District reservoir with an analyzed TDS of 674 mg/l.

Injection Pressure Limitation

Injection pressure, measured at the wellhead, shall not exceed a maximum calculated to assure that the pressure used during injection does not initiate new fractures or propagate existing fractures in the confining zones adjacent to the USDWs.

The applicant submitted injection fluid density and injection zone data which was used to calculate a formation fracture pressure and to determine the maximum allowable injection pressure (MAIP), as measured at the surface, for this Permit,

TABLE 5.1 lists the fracture gradient for the injection zone and the approved MAIP, determined according to the following formula:

$$FP = [fg - (0.433 * sg)] * d$$

FP = formation fracture pressure (measured at surface)
fg = fracture gradient (from submitted data or tests)
sg = specific gravity (of injected fluid)
d = depth to top of injection zone (or top perforation)

Injection Volume Limitation

Cumulative injected fluid volume limits are set to assure that injected fluids remain within the boundary of the exempted area. Cumulative injected fluid volume is limited when injection occurs into an aquifer that has been exempted from protection as a USDW.

There will be no restrictions on the cumulative volume of authorized fluid injected into the Green River interval 3673 feet to the top of the Wasatch Formation, which is estimated to be 6062 feet.

Mechanical Integrity (40 CFR 146.8)

An injection well has mechanical integrity if:

1. there is no significant leak in the casing, tubing, or packer (Part I); and
2. there is no significant fluid movement into a USDW through vertical channels adjacent to the injection well bore (Part II).

The Permit prohibits injection into a well which lacks mechanical integrity.

The Permit requires that the well demonstrate mechanical integrity prior to injection and periodically thereafter. A demonstration of mechanical integrity includes both internal (Part I) and external (Part II). The methods and frequency for demonstrating Part I and Part II mechanical integrity are dependent upon well-specific conditions as explained below.

Well construction and site-specific conditions dictate the following requirements for Mechanical Integrity (MI) demonstrations:

PART I MI: Internal MI will be demonstrated prior to beginning injection. Since this well is constructed with a standard casing, tubing, and packer configuration, a successful mechanical integrity test (MIT) is required to take place at least once every five (5) years. A demonstration of Part I MI is also required prior to resuming injection following any workover operation that affects the casing, tubing or packer. Part I MI may be demonstrated by a standard tubing-casing annulus pressure test using the maximum permitted injection pressure or 1000 psi, which ever is less, with a ten (10) percent or less pressure loss over thirty (30) minutes.

PART II MI: - The CBL indicates that cement does not meet minimum requirements needed to demonstrate zone isolation (at least 18 feet of continuous 80% bond, or better) through the confining zone. Therefore, further testing for Part II MI will be required prior to injection and at least once every five years thereafter. The demonstration shall be by temperature survey or other approved test. Approved tests for demonstrating Part II MI include a temperature survey, noise log or oxygen activation log, and Region 8 may also accept results of a Radioactive Tracer Survey under certain circumstances.

PART VI. Monitoring, Recordkeeping and Reporting Requirements

Injection Well Monitoring Program

At least once a year the permittee must analyze a sample of the injected fluid for total dissolved solids (TDS), specific conductivity, pH, and specific gravity. This analysis shall be reported to EPA annually as part of the Annual Report to the Director. Any time a new source of injected fluid is added, a fluid analysis shall be made of the new source.

Instantaneous injection pressure, injection flow rate, cumulative fluid volume and TCA pressures must be observed on a weekly basis. A recording, at least once every thirty (30) days, must be made of the injection pressure, injection flow rate and cumulative fluid volume, and the maximum and average value for each must be determined for each month. This information is required to be reported annually as part of the Annual Report to the Director.

PART VII. Plugging and Abandonment Requirements (40 CFR 146.10)

All cement plugs will be set with tubing.

9.2 ppg plugging gel, or fresh water weighted with bentonite or treated brine will be placed between all plugs.

The following Plugging and Abandonment Plan (P&A Plan), as proposed by the applicant, is predicated on the permittee not revising the current-proposed injection perforations as cited on the schematic diagram of well conversion. Should the uppermost perforations (4092 feet - 4097 feet) be modified in conversion, the EPA will modify the P&A Plan accordingly.

Plug No. 3 has been revised from the Draft Permit to extend Plug No. 3 from a total depth of 383 feet to 750 feet. Plug No. 3 in the Draft Permit did not consider the base of the USDWs to be at a depth from surface of 700 feet.

PLUG NO. 1: Set a cast iron bridge plug (CIBP) at 3997 feet with 100 sacks of Class "G" cement on top of CIBP.

PLUG NO. 2: Set a Class "G" cement plug frpm 2000 feet - 2200 feet as requested by the Bureau of Land Management (BLM). This plug will also cover the top of the Green River Formation as required by the BLM.

PLUG NO. 3: Set a cement plug within the 5-1/2 inch casing to a depth of 750 feet. Plug No. 3 will also include a cement plug within the 5-1/2 inch X 8-5/8 inch casing annulus and the 5-1/2 inch X 7-7/8 inch annulus from the surface to a depth of 750 feet.

Plugging and Abandonment Plan

Prior to abandonment, the well shall be plugged in a manner that isolates the injection zone and prevents movement of fluid into or between USDWs, and in accordance with other applicable federal, State or local law or regulation. Tubing, packer and other downhole apparatus shall be removed. Cement with additives such as accelerators and retarders that control or enhance cement properties may be used for plugs; however, volume-extending additives and gel cements are not approved for plug use. Plug placement shall be verified by tagging. Plugging gel of at least 9.6 lb/gal shall be placed between all plugs. A minimum 50 ft surface plug shall be set inside and outside of the surface casing to seal pathways for fluid migration into the subsurface. Within sixty (60) days after plugging the owner or operator shall submit Plugging Record (EPA Form 7520 13) to the Director. The Plugging Record must be certified as accurate and complete by the person responsible for the plugging operation. The plugging and abandonment plan is described in Appendix E of the Permit.

PART VIII. Financial Responsibility (40 CFR 144.52)

Financial Statement was reviewed and approved by the EPA on September 25, 2006.

Demonstration of Financial Responsibility

The permittee is required to maintain financial responsibility and resources to close, plug, and abandon the underground injection operation in a manner prescribed by the Director. The permittee shall show evidence of such financial responsibility to the Director by the submission of a surety bond, or other adequate assurance such as financial statements or other materials acceptable to the Director. The Regional Administrator may, on a periodic basis, require the holder of a lifetime permit to submit a revised estimate of the resources needed to plug and abandon the well to reflect inflation of such costs, and a revised demonstration of financial responsibility if necessary. Initially, the operator has chosen to demonstrate financial responsibility with:

Financial Statement, received April 22, 2005

Evidence of continuing financial responsibility is required to be submitted to the Director annually.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 8
1595 WYNKOOP STREET
DENVER, CO 80202-1129
http://www.epa.gov/region8

AUG 1 7 2010

Ref: 8P-W-GW

CERTIFIED MAIL
RETURN RECEIPT REQUESTED

Accepted by the Utah Division of Oil, Gas and Mining FOR RECORD ONLY

Eric Sundberg
Newfield Production Company
1001 Seventeenth Street, Suite 2000
Denver, CO 80202

RECEIVED
AUG 2 5 2010
DIV. OF OIL, GAS & MINING

Re: FINAL Permit
EPA UIC Permit UT20998-06753
Well: Blackjack Federal 10-5-9-17
NWSE Sec. 5-T9S-R17E
Duchesne County, UT
API No.: 43-013-32553

Dear Mr. Sundberg:

Enclosed is your copy of the FINAL Underground Injection Control (UIC) Permit for the proposed Blackjack Federal 10-5-9-17 injection well. A Statement of Basis that discusses the conditions and requirements of this EPA UIC Permit, is also included.

The Public Comment period for this Permit ended on AUG 0 9 2010. No comments on the Draft Permit were received during the Public Notice period; therefore the Effective Date for this EPA UIC Permit is the date of issuance. All conditions set forth herein refer to Title 40 Parts 124, 144, 146, and 147 of the Code of Federal Regulations (CFR) and are regulations that are in effect as of the Effective Date of this Permit.

Please note that under the terms and conditions of this Final Permit you are authorized only to construct the proposed injection well. Prior to commencing injection, you first must fulfill all "Prior to Commencing Injection" requirements of the Final Permit, Part II Section C.1, and obtain written Authorization to Inject from the EPA. It is your responsibility to be familiar with and to comply with all provisions of your Final Permit. The EPA forms referenced in the permit are available at http://www.epa.gov/safewater/uic/reportingforms.html. Guidance documents for Cement Bond Logging, Radioactive Tracer testing, Step Rate testing, Mechanical Integrity demonstration, Procedure in the Event of a Mechanical Integrity Loss, and other UIC guidances, are available at http://www.epa.gov/region8/water/uic/ deep_injection.html. Upon request, hard copies of the EPA forms and guidances can be provided.

This EPA UIC Permit is issued for the operating life of the well unless terminated (Part III, Section B). The EPA may review this Permit at least every five (5) years to determine whether any action is warranted pursuant to 40 CFR § 144.36(a).

If you have any questions on the enclosed Final Permit or Statement of Basis, please call Emmett Schmitz of my staff at (303) 312-6174, or toll-free at (800) 227-8917, ext. 312-6174.

Sincerely,

Stephen S. Tuber
Assistant Regional Administrator
Office of Partnerships and Regulatory Assistance

enclosure: Final UIC Permit
Statement of Basis

cc: Letter only:

Uintah & Ouray Business Committee, Ute Indian Tribe:
Curtis Cesspooch, Chairman
Frances Poowegup, Vice-Chairwoman
Irene Cuch, Councilwoman
Stewart Pike, Councilman
Philip Chimburas, Councilman
Richard Jenks,Jr., Councilman

Daniel Picard, Superintendent
Uintah & Ouray Indian Agency
U.S. Bureau of Indian Affairs

cc: all enclosures:

Michael Guinn
District Manager
Newfield Production Company
Myton, Utah

Mike Natchees
Environmental Coordinator
Ute Indian Tribe

Manual Myore
Director
Energy & Minerals Dept.
Ute Undian Tribe

Brad Hill
Acting Associate Director
State of Utah - Natural Resources

Fluid Minerals Engineering Dept.
U.S. Bureau of Land Management
Vernal, Utah

EPA

UNDERGROUND INJECTION CONTROL PROGRAM

PERMIT

PREPARED: August 2010

Permit No. UT20998-06753

Class II Enhanced Oil Recovery Injection Well

Blackjack Federal 10-5-9-17
Duchesne County, UT

Issued To

Newfield Production Co.

1001 Seventeenth Street, Suite 2000

Denver, CO 80202

Part I. AUTHORIZATION TO CONSTRUCT AND OPERATE

Under the authority of the Safe Drinking Water Act and Underground Injection Control (UIC) Program regulations of the U. S. Environmental Protection Agency (EPA) codified at Title 40 of the Code of Federal Regulations (40 CFR) Parts 2, 124, 144, 146, and 147, and according to the terms of this Permit,

Newfield Production Co. 1001 Seventeenth Street, Suite 2000 Denver, CO 80202

is authorized to construct and to operate the following Class II injection well or wells:

Blackjack Federal 10-5-9-17 1676' FSL 1982' FEL, NWSE S5, T9S, R17E Duchesne County, UT

EPA regulates the injection of fluids into injection wells so that injection does not endanger underground sources of drinking water (USDWs). EPA UIC Permit conditions are based on authorities set forth at 40 CFR Parts 144 and 146, and address potential impacts to USDWs.

Under 40 CFR Part 144, Subpart D, certain conditions apply to all UIC Permits and may be incorporated either expressly or by reference. General permit conditions for which the content is mandatory and not subject to site-specific differences are not discussed in this document. Issuance of this Permit does not convey any property rights of any sort or any exclusive privilege, nor does it authorize injury to persons or property or invasion of other private rights, or any infringement of other Federal, State or local laws or regulations. (40 CFR §144.35) An EPA UIC Permit may be issued for the operating life of the injection well or project unless terminated for reasonable cause under 40 CFR §144.39, 144.40 and 144.41, and may be reviewed at least once every five (5) years to determine if action is required under 40 CFR §144.36(a).

This Permit is issued for the life of the well(s) unless modified, revoked and reissued, or terminated under 40 CFR §144.39 or 144.40. This EPA Permit may be adopted, modified, revoked and reissued, or terminated if primary enforcement authority for a UIC Program is delegated to an Indian Tribe or State. Upon the effective date of delegation, reports, notifications, questions and other correspondence should be directed to the Indian Tribe or State Director.

Issue Date: AUG 17 2010 Effective Date AUG 17 2010

Stephen S. Tuber
Assistant Regional Administrator*
Office of Partnerships and Regulatory Assistance

*NOTE: The person holding this title is referred to as the "Director" throughout this Permit.

PART II. SPECIFIC PERMIT CONDITIONS

Section A. WELL CONSTRUCTION REQUIREMENTS

These requirements represent the approved minimum construction standards for well casing and cement, injection tubing, and packer.

Details of the approved well construction plan are incorporated into this Permit as APPENDIX A. Changes to the approved plan that may occur during construction must be approved by the Director prior to being physically incorporated.

1. *Casing and Cement.*

The well or wells shall be cased and cemented to prevent the movement of fluids into or between underground sources of drinking water. The well casing and cement shall be designed for the life expectancy of the well and of the grade and size shown in APPENDIX A. Remedial cementing may be required if shown to be inadequate by cement bond log or other attempted demonstration of Part II (External) mechanical integrity.

2. *Injection Tubing and Packer.*

Injection tubing is required, and shall be run and set with a packer at or below the depth indicated in APPENDIX A. The packer setting depth may be changed provided it remains below the depth indicated in APPENDIX A and the Permittee provides notice and obtains the Director's approval for the change.

3. *Sampling and Monitoring Devices.*

The Permittee shall install and maintain in good operating condition:

(a) a "tap" at a conveniently accessible location on the injection flow line between the pump house or storage tanks and the injection well, isolated by shut-off valves, for collection of representative samples of the injected fluid; and

(b) one-half (1/2) inch female iron pipe fitting, isolated by shut-off valves and located at the wellhead at a conveniently accessible location, for the attachment of a pressure gauge capable of monitoring pressures ranging from normal operating pressures up to the Maximum Allowable Injection Pressure specified in APPENDIX C:

   (i) on the injection tubing; and

   (ii) on the tubing-casing annulus (TCA); and

(c) a pressure actuated shut-off device attached to the injection flow line set to shut-off the injection pump when or before the Maximum Allowable Injection Pressure (MAIP) specified in APPENDIX C is reached at the wellhead; and

(d) a non-resettable cumulative volume recorder attached to the injection line.

4. *Well Logging and Testing*

Well logging and testing requirements are found in APPENDIX B. The Permittee shall ensure the log and test requirements are performed within the time frames specified in APPENDIX B. Well logs and tests shall be performed according to current EPA-approved procedures. Well log and test results shall be submitted to the Director within sixty (60) days of completion of the logging or testing activity, and shall include a report describing the methods used during logging or testing and an interpretation of the test or log results.

5. *Postponement of Construction or Conversion*

The Permittee shall complete well construction within one year of the Effective Date of the Permit, or in the case of an Area Permit within one year of Authorization of the additional well. Authorization to construct and operate shall expire if the well has not been constructed within one year of the Effective Date of the Permit or Authorization and the Permit may be terminated under 40 CFR 144.40, unless the Permittee has notified the Director and requested an extension prior to expiration. Notification shall be in writing, and shall state the reasons for the delay and provide an estimated completion date. Once Authorization has expired under this part, the complete permit process including opportunity for public comment may be required before Authorization to construct and operate may be reissued.

6. *Workovers and Alterations*

Workovers and alterations shall meet all conditions of the Permit. Prior to beginning any addition or physical alteration to an injection well that may significantly affect the tubing, packer or casing, the Permittee shall give advance notice to the Director and obtain the Director's approval. The Permittee shall record all changes to well construction on a Well Rework Record (EPA Form 7520-12), and shall provide this and any other record of well workover, logging, or test data to EPA within sixty (60) days of completion of the activity.

A successful demonstration of Part I MI is required following the completion of any well workover or alteration which affects the casing, tubing, or packer. Injection operations shall not be resumed until the well has successfully demonstrated mechanical integrity and the Director has provided written approval to resume injection.

Section B. MECHANICAL INTEGRITY

The Permittee is required to ensure each injection well maintains mechanical integrity at all times. The Director, by written notice, may require the Permittee to comply with a schedule describing when mechanical integrity demonstrations shall be made.

An injection well has mechanical integrity if:

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

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

1. Demonstration of Mechanical Integrity (MI).

The operator shall demonstrate MI prior to commencing injection and periodically thereafter. Well-specific conditions dictate the methods and the frequency for demonstrating MI and are discussed in the Statement of Basis. The logs and tests are designed to demonstrate both internal (Part I) and external (Part II) MI as described above. The conditions present at this well site warrant the methods and frequency required in Appendix B of this Permit.

In addition to these regularly scheduled demonstrations of MI, the operator shall demonstrate internal (Part I) MI after any workover which affects the tubing, packer or casing.

The Director may require additional or alternative tests if the results presented by the operator are not satisfactory to the Director to demonstrate there is no movement of fluid into or between USDWs resulting from injection activity. Results of MI tests shall be submitted to the Director as soon as possible but no later than sixty (60) days after the test is complete.

2. Mechanical Integrity Test Methods and Criteria

EPA-approved methods shall be used to demonstrate mechanical integrity. Ground Water Section Guidance No. 34 "Cement Bond Logging Techniques and Interpretation", Ground Water Section Guidance No. 37, "Demonstrating Part II (External) Mechanical Integrity for a Class II injection well permit", and Ground Water Section Guidance No. 39, "Pressure Testing Injection Wells for Part I (Internal) Mechanical Integrity" are available from EPA and will be provided upon request.

The Director may stipulate specific test methods and criteria best suited for a specific well construction and injection operation.

3. Notification Prior to Testing.

The Permittee shall notify the Director at least seven calendar days prior to any mechanical integrity test unless the mechanical integrity test is conducted after a well construction, well conversion, or a well rework, in which case any prior notice is sufficient. The Director may allow a shorter notification period if it would be sufficient to enable EPA to witness the mechanical integrity test. Notification may be in the form of a yearly or quarterly schedule of planned mechanical integrity tests, or it may be on an individual basis.

4. Loss of Mechanical Integrity.

If the well fails to demonstrate mechanical integrity during a test, or a loss of mechanical integrity becomes evident during operation (such as presence of pressure in the TCA, water flowing at the surface, etc.), the Permittee shall notify the Director within 24 hours (see Part III Section E Paragraph 11(e) of this Permit) and the well shall be shut-in within 48 hours unless the Director requires immediate shut-in.

Within five days, the Permittee shall submit a follow-up written report that documents test results, repairs undertaken or a proposed remedial action plan.

Injection operations shall not be resumed until after the well has successfully been repaired and demonstrated mechanical integrity, and the Director has provided approval to resume injection.

Section C. WELL OPERATION

INJECTION BETWEEN THE OUTERMOST CASING PROTECTING UNDERGROUND SOURCES OF DRINKING WATER AND THE WELL BORE IS PROHIBITED.

Injection is approved under the following conditions:

1. Requirements Prior to Commencing Injection.

Well injection, including for new wells authorized by an Area Permit under 40 CFR 144.33 (c), may commence only after all well construction and pre-injection requirements herein have been met and approved. The Permittee may not commence injection until construction is complete, and

(a) The Permittee has submitted to the Director a notice of completion of construction and a completed EPA Form 7520-10 or 7520-12; all applicable logging and testing requirements of this Permit (see APPENDIX B) have been fulfilled and the records submitted to the Director; mechanical integrity pursuant to 40 CFR 146.8 and Part II Section B of this Permit has been demonstrated; and

(i) The Director has inspected or otherwise reviewed the new injection well and finds it is in compliance with the conditions of the Permit; or

(ii) The Permittee has not received notice from the Director of his or her intent to inspect or otherwise review the new injection well within 13 days of the date of the notice in Paragraph 1a, in which case prior inspection or review is waived and the Permittee may commence injection.

2. Injection Interval.

Injection is permitted only within the approved injection interval, listed in APPENDIX C. Additional individual injection perforations may be added provided that they remain within the approved injection interval and the Permittee provides notice to the Director in accordance with Part II, Section A, Paragraph 6.

3. Injection Pressure Limitation

(a) The permitted Maximum Allowable Injection Pressure (MAIP), measured at the wellhead, is found in APPENDIX C. Injection pressure shall not exceed the amount the Director determines is appropriate to ensure that injection does not initiate new fractures or propagate existing fractures in the confining zone adjacent to USDWs. In no case shall injection pressure cause the movement of injection or formation fluids into a USDW.

(b) The Permittee may request a change of the MAIP, or the MAIP may be increased or decreased by the Director in order to ensure that the requirements in Paragraph (a) above are fulfilled. The Permitee may be required to conduct a step rate injection test or other suitable test to provide information for determining the fracture pressure of the injection zone. Change of the permitted MAIP by the Director shall be by modification of this Permit and APPENDIX C.

4. *Injection Volume Limitation.*
Injection volume is limited to the total volume specified in APPENDIX C.

5. *Injection Fluid Limitation.*
Injected fluids are limited to those identified in 40 CFR 144.6(b)(2) as fluids used for enhanced recovery of oil or natural gas, including those which are brought to the surface in connection with conventional oil or natural gas production that may be commingled with waste waters from gas plants which are an integral part of production operations unless those waters are classified as a hazardous waste at the time of injection, pursuant to 40 CFR 144.6(b). Non-exempt wastes, including unused fracturing fluids or acids, gas plant cooling tower cleaning wastes, service wastes and vacuum truck wastes, are NOT approved for injection. This well is NOT approved for commercial brine injection, industrial waste fluid disposal or injection of hazardous waste as defined by CFR 40 Part 261. The Permittee shall provide a listing of the sources of injected fluids in accordance with the reporting requirements in Part II Section D Paragraph 4 and APPENDIX D of this Permit.

6. *Tubing-Casing Annulus (TCA)*
The tubing-casing annulus (TCA) shall be filled with water treated with a corrosion inhibitor, or other fluid approved by the Director. The TCA valve shall remain closed during normal operating conditions and the TCA pressure shall be maintained at zero (0) psi.

If TCA pressure cannot be maintained at zero (0) psi, the Permittee shall follow the procedures in Ground Water Section Guidance No. 35 "Procedures to follow when excessive annular pressure is observed on a well."

Section D. MONITORING, RECORDKEEPING, AND REPORTING OF RESULTS

1. *Monitoring Parameters, Frequency, Records and Reports.*
Monitoring parameters are specified in APPENDIX D. Pressure monitoring recordings shall be taken at the wellhead. The listed parameters are to be monitored, recorded and reported at the frequency indicated in APPENDIX D even during periods when the well is not operating.

Monitoring records must include:

(a) the date, time, exact place and the results of the observation, sampling, measurement, or analysis, and;

(b) the name of the individual(s) who performed the observation, sampling, measurement, or analysis, and;

(c) the analytical techniques or methods used for analysis.

2. *Monitoring Methods.*

(a) Monitoring observations, measurements, samples, etc. taken for the purpose of complying with these requirements shall be representative of the activity or condition being monitored.

(b) Methods used to monitor the nature of the injected fluids must comply with analytical methods cited and described in Table 1 of 40 CFR 136.3 or Appendix III of 40 CFR 261, or by other methods that have been approved in writing by the Director.

(c) Injection pressure, annulus pressure, injection rate, and cumulative injected volumes shall be observed and recorded at the wellhead under normal operating conditions, and all parameters shall be observed simultaneously to provide a clear depiction of well operation.

(d) Pressures are to be measured in pounds per square inch (psi).

(e) Fluid volumes are to be measured in standard oil field barrels (bbl).

(f) Fluid rates are to be measured in barrels per day (bbl/day).

3. Records Retention.

(a) Records of calibration and maintenance, and all original strip chart recordings for continuous monitoring instrumentation, copies of all reports required by this permit, and records of all data used to complete the application for this permit shall be retained for a period of AT LEAST THREE (3) YEARS from the date of the sample, measurement, report, or application. This period may be extended anytime prior to its expiration by request of the Director.

(b) Records of the nature and composition of all injected fluids must be retained until three (3) years after the completion of any plugging and abandonment (P&A) procedures specified under 40 CFR 144.52(a)(6) or under Part 146 Subpart G, as appropriate. The Director may require the Permittee to deliver the records to the Director at the conclusion of the retention period. The Permittee shall continue to retain the records after the three (3) year retention period unless the Permittee delivers the records to the Director or obtains written approval from the Director to discard the records.

4. Annual Reports.

Whether the well is operating or not, the Permittee shall submit an Annual Report to the Director that summarizes the results of the monitoring required by Part II Section D and APPENDIX D.

The first Annual Report shall cover the period from the effective date of the Permit through December 31 of that year. Subsequent Annual Reports shall cover the period from January 1 through December 31 of the reporting year. Annual Reports shall be submitted by February 15 of the year following data collection. EPA Form 7520-11 may be copied and shall be used to submit the Annual Report, however, the monitoring requirements specified in this Permit are mandatory even if EPA Form 7520-11 indicates otherwise.

Section E. PLUGGING AND ABANDONMENT

1. Notification of Well Abandonment, Conversion or Closure.

The Permittee shall notify the Director in writing at least forty-five (45) days prior to: 1) plugging and abandoning an injection well, 2) converting to a non-injection well, and 3) in the case of an Area Permit, before closure of the project.

2. Well Plugging Requirements

Prior to abandonment, the injection well shall be plugged with cement in a manner which isolates the injection zone and prevents the movement of fluids into or between underground sources of drinking water, and in accordance with 40 CFR 146.10 and other applicable Federal, State or local law or regulations. Tubing, packer and other downhole apparatus shall be removed. Cement with additives such as accelerators and retarders that control or enhance cement properties may be used for plugs; however, volume-extending additives and gel cements are not approved for plug use. Plug placement shall be verified by tagging. Plugging gel of at least 9.2 lb/gal shall be placed between all plugs. A minimum 50 ft surface plug shall be set inside and outside of the surface casing to seal pathways for fluid migration into the subsurface. The Plugging Record must be certified as accurate and complete by the person responsible for the plugging operation. Prior to placement of the cement plug(s) the well shall be in a state of static equilibrium with the mud weight equalized top to bottom, either by circulating the mud in the well at least once or by a comparable method prescribed by the Director.

3. Approved Plugging and Abandonment Plan.

The approved plugging and abandonment plan is incorporated into this Permit as APPENDIX E. Changes to the approved plugging and abandonment plan must be approved by the Director prior to beginning plugging operations. The Director also may require revision of the approved plugging and abandonment plan at any time prior to plugging the well.

4. Forty Five (45) Day Notice of Plugging and Abandonment.

The Permittee shall notify the Director at least forty-five (45) days prior to plugging and abandoning a well and provide notice of any anticipated change to the approved plugging and abanonment plan.

5. Plugging and Abandonment Report.

Within sixty (60) days after plugging a well, the Permittee shall submit a report (EPA Form 7520-13) to the Director. The plugging report shall be certified as accurate by the person who performed the plugging operation. Such report shall consist of either:

(a) A statement that the well was plugged in accordance with the approved plugging and abandonment plan; or

(b) Where actual plugging differed from the approved plugging and abandonment plan, an updated version of the plan, on the form supplied by the Director, specifying the differences.

6. Inactive Wells.

After any period of two years during which there is no injection the Permittee shall plug and abandon the well in accordance with Part II Section E Paragraph 2 of this Permit unless the Permittee:

(a) Provides written notice to the Director;

(b) Describes the actions or procedures the Permittee will take to ensure that the well will not endanger USDWs during the period of inactivity. These actions and procedures shall include compliance with mechanical integrity demonstration, Financial Responsibility and all other permit requirements designed to protect USDWs; and

(c) Receives written notice by the Director temporarily waiving plugging and abandonment requirements.

PART III. CONDITIONS APPLICABLE TO ALL PERMITS

Section A. EFFECT OF PERMIT

The Permittee is allowed to engage in underground injection in accordance with the conditions of this Permit. The Permittee shall not construct, operate, maintain, convert, plug, abandon, or conduct any other activity in a manner that allows the movement of fluid containing any contaminant into underground sources of drinking water, if the presence of that contaminant may cause a violation of any primary drinking water regulation under 40 CFR 142 or may otherwise adversely affect the health of persons. Any underground injection activity not authorized by this Permit or by rule is prohibited. Issuance of this Permit does not convey property rights of any sort or any exclusive privilege; nor does it authorize any injury to persons or property, any invasion of other private rights, or any infringement of any other Federal, State or local law or regulations. Compliance with the terms of this Permit does not constitute a defense to any enforcement action brought under the provisions of Section 1431 of the Safe Drinking Water Act (SDWA) or any other law governing protection of public health or the environment, for any imminent and substantial endangerment to human health or the environment, nor does it serve as a shield to the Permittee's independent obligation to comply with all UIC regulations. Nothing in this Permit relieves the Permittee of any duties under applicable regulations.

Section B. CHANGES TO PERMIT CONDITIONS

1. Modification, Reissuance, or Termination.

The Director may, for cause or upon a request from the Permittee, modify, revoke and reissue, or terminate this Permit in accordance with 40 CFR 124.5, 144.12, 144.39, and 144.40. Also, this Permit is subject to minor modification for causes as specified in 40 CFR 144.41. The filing of a request for modification, revocation and reissuance, termination, or the notification of planned changes or anticipated noncompliance on the part of the Permittee does not stay the applicability or enforceability of any condition of this Permit.

2. Conversions.

The Director may, for cause or upon a written request from the Permittee, allow conversion of the well from a Class II injection well to a non-Class II well. Conversion may not proceed until the Permittee receives written approval from the Director. Conditions of such conversion may include but are not limited to, approval of the proposed well rework, follow up demonstration of mechanical integrity, well-specific monitoring and reporting following the conversion, and demonstration of practical use of the converted configuration.

3. Transfer of Permit.

Under 40 CFR 144.38, this Permit is transferable provided the current Permittee notifies the Director at least thirty (30) days in advance of the proposed transfer date (EPA Form 7520-7) and provides a written agreement between the existing and new Permittees containing a specific date for transfer of Permit responsibility, coverage and liability between them. The notice shall adequately demonstrate that the financial responsibility requirements of 40 CFR 144.52(a)(7) will be met by the new Permittee. The Director may require modification or revocation and reissuance of the Permit to change the name of the Permittee and incorporate such other requirements as may be necessary under the Safe Drinking Water Act; in some cases, modification or revocation and reissuance is mandatory.

4. Permittee Change of Address.

Upon the Permittee's change of address, or whenever the operator changes the address where monitoring records are kept, the Permittee must provide written notice to the Director within 30 days.

5. Construction Changes, Workovers, Logging and Testing Data

The Permittee shall give advance notice to the Director, and shall obtain the Director's written approval prior to any physical alterations or additions to the permitted facility. Alterations or workovers shall meet all conditions as set forth in this permit. The Permittee shall record any changes to the well construction on a Well Rework Record (EPA Form 7520-12), and shall provide this and any other record of well workovers, logging , or test data to EPA within sixty (60) days of completion of the activity.

Following the completion of any well workovers or alterations which affect the casing, tubing, or packer, a successful demonstration of mechanical integrity (Part III, Section F of this Permit) shall be made, and written authorization from the Director received, prior to resuming injection activities.

Section C. SEVERABILITY

The Provisions of this Permit are severable, and if any provision of this Permit or the application of any provision of this Permit to any circumstance, is held invalid, the application of such provision to other circumstances, and the remainder of this Permit shall not be affected thereby.

Section D. CONFIDENTIALITY

In accordance with 40 CFR Part 2 and 40 CFR 144.5, information submitted to EPA pursuant to this Permit may be claimed as confidential by the submitter. Any such claim must be asserted at the time of submission by stamping the words "confidential business information" on each page containing such information. If no claim is made at the time of submission, EPA may make the information available to the public without further notice. If a claim is asserted, the validity of the claim will be assessed in accordance with the procedures in 40 CFR Part 2 (Public Information). Claims of confidentiality for the following information will be denied:

- The name and address of the Permittee, and
- information which deals with the existence, absence or level of contaminants in drinking water.

Section E. GENERAL PERMIT REQUIREMENTS

1. Duty to Comply.

The Permittee must comply with all conditions of this Permit. Any noncompliance constitutes a violation of the Safe Drinking Water Act (SDWA) and is grounds for enforcement action; for Permit termination, revocation and reissuance, or modification; or for denial of a permit renewal application; except that the Permittee need not comply with the provisions of this Permit to the extent and for the duration such noncompliance is authorized in an emergency permit under 40 CFR 144.34. All violations of the SDWA may subject the Permittee to penalties and/or criminal prosecution as specified in Section 1423 of the SDWA.

2. *Duty to Reapply.*

If the Permittee wishes to continue an activity regulated by this Permit after the expiration date of this Permit, under 40 CFR 144.37 the Permittee must apply for a new permit prior to the expiration date.

3. *Need to Halt or Reduce Activity Not a Defense.*

It shall not be a defense for a Permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this Permit.

4. *Duty to Mitigate.*

The Permittee shall take all reasonable steps to minimize or correct any adverse impact on the environment resulting from noncompliance with this Permit.

5. *Proper Operation and Maintenance.*

The Permittee shall at all times properly operate and maintain all facilities and systems of treatment and control (and related appurtenances) which are installed or used by the Permittee to achieve compliance with the conditions of this Permit. Proper operation and maintenance includes effective performance, adequate funding, adequate operator staffing and training, and adequate laboratory and process controls, including appropriate quality assurance procedures. This provision requires the operation of back-up or auxiliary facilities or similar systems only when necessary to achieve compliance with the conditions of this Permit.

6. *Permit Actions.*

This Permit may be modified, revoked and reissued or terminated for cause. The filing of a request by the Permittee for a permit modification, revocation and reissuance, or termination, or a notification of planned changes or anticipated noncompliance, does not stay any permit condition.

7. *Property Rights.*

This Permit does not convey any property rights of any sort, or any exclusive privilege.

8. *Duty to Provide Information.*

The Permittee shall furnish to the Director, within a time specified, any information which the Director may request to determine whether cause exists for modifying, revoking and reissuing, or terminating this permit, or to determine compliance with this permit. The Permittee shall also furnish to the Director, upon request, copies of records required to be kept by this Permit. The Permittee is required to submit any information required by this Permit or by the Director to the mailing address designated in writing by the Director.

9. *Inspection and Entry.*

The Permittee shall allow the Director, or an authorized representative, upon the presentation of credentials and other documents as may be required by law, to:

(a) Enter upon the Permittee's premises where a regulated facility or activity is located or conducted, or where records must be kept under the conditions of this Permit;

(b) Have access to and copy, at reasonable times, any records that must be kept under the conditions of this Permit;

(c) Inspect at reasonable times any facilities, equipment (including monitoring and control equipment), practices, or operations regulated or required under this Permit; and,

(d) Sample or monitor at reasonable times, for the purpose of assuring permit compliance or as otherwise authorized by the SDWA, any substances or parameters at any location.

10. Signatory Requirements.

All applications, reports or other information submitted to the Director shall be signed and certified according to 40 CFR 144.32. This section explains the requirements for persons duly authorized to sign documents, and provides wording for required certification.

11. Reporting Requirements.

(a) Planned changes. The Permittee shall give notice to the Director as soon as possible of any planned changes, physical alterations or additions to the permitted facility, and prior to commencing such changes.

(b) Anticipated noncompliance. The Permittee shall give advance notice to the Director of any planned changes in the permitted facility or activity which may result in noncompliance with permit requirements.

(c) Monitoring Reports. Monitoring results shall be reported at the intervals specified in this Permit.

(d) Compliance schedules. Reports of compliance or noncompliance with, or any progress reports on, interim and final requirements contained in any compliance schedule of this Permit shall be submitted no later than 30 days following each schedule date.

(e) Twenty-four hour reporting. The Permittee shall report to the Director any noncompliance which may endanger human health or the environment, including:

(i) Any monitoring or other information which indicates that any contaminant may cause endangerment to a USDW; or

(ii) Any noncompliance with a permit condition or malfunction of the injection system which may cause fluid migration into or between USDWs.

Information shall be provided, either directly or by leaving a message, within twenty-four (24) hours from the time the permittee becomes aware of the circumstances by telephoning (800) 227-8917 and requesting EPA Region VIII UIC Program Compliance and Technical Enforcement Director, or by contacting the EPA Region VIII Emergency Operations Center at (303) 293-1788.

In addition, a follow up written report shall be provided to the Director within five (5) days of the time the Permittee becomes aware of the circumstances. The written submission shall contain a description of the noncompliance and its cause, the period of noncompliance including exact dates and times, and if the noncompliance has not been corrected the anticipated time it is expected to continue; and the steps taken or planned to reduce, eliminate, and prevent recurrence of the noncompliance.

(f) Oil Spill and Chemical Release Reporting: The Permittee shall comply with all reporting requirements related to the occurence of oil spills and chemical releases by contacting the National Response Center (NRC) at (800) 424-8802, (202) 267-2675, or through the NRC website http://www.nrc.uscg.mil/index.htm.

(g) Other Noncompliance. The Permittee shall report all instances of noncompliance not reported under paragraphs Part III, Section E Paragraph 11(b) or Section E, Paragraph 11(e) at the time the monitoring reports are submitted. The reports shall contain the information listed in Paragraph 11(e) of this Section.

(h) Other information. Where the Permittee becomes aware that it failed to submit any relevant facts in the permit application, or submitted incorrect information in a permit application or in any report to the Director, the Permittee shall promptly submit such facts or information to the Director.

Section F. FINANCIAL RESPONSIBILITY

1. Method of Providing Financial Responsibility.

The Permittee shall maintain continuous compliance with the requirement to maintain financial responsibility and resources to close, plug, and abandon the underground injection well(s). No substitution of a demonstration of financial responsibility shall become effective until the Permittee receives written notification from the Director that the alternative demonstration of financial responsibility is acceptable. The Director may, on a periodic basis, require the holder of a permit to revise the estimate of the resources needed to plug and abandon the well to reflect changes in such costs and may require the Permittee to provide a revised demonstration of financial responsibility.

2. Insolvency.

In the event of:

(a) the bankruptcy of the trustee or issuing institution of the financial mechanism; or

(b) suspension or revocation of the authority of the trustee institution to act as trustee; or

(c) the institution issuing the financial mechanism losing its authority to issue such an instrument

the Permittee must notify the Director in writing, within ten (10) business days, and the Permittee must establish other financial assurance or liability coverage acceptable to the Director within sixty (60) days after any event specified in (a), (b), or (c) above.

The Permittee must also notify the Director by certified mail of the commencement of voluntary or involuntary proceedings under Title 11 (Bankruptcy), U.S. Code naming the owner or operator as debtor, within ten (10) business days after the commencement of the proceeding. A guarantor, if named as debtor of a corporate guarantee, must make such a notification as required under the terms of the guarantee.

APPENDIX A

WELL CONSTRUCTION REQUIREMENTS

See diagram.

Blackjack Federal 10-5-9-17 was drilled to a total depth of 6,015 feet (KB) feet in the Basal Carbonate Member of the Green River Formation.

Surface casing (8-5/8 inch) was set at a depth of 333 feet in a 12-1/4 inch hole using 160 sacks of Class "G" cement which was circulated to the surface.

Production casing (5-1/2 inch) was set at a depth of 5,985 feet (KB) in a 7-7/8 inch hole with 350 sacks of Premium Lite II and 400 sacks of 50/50 poz mix. The Shale "B" Confining Zone is absent 80% bond index cement.

A Radioactive Tracer Survey (RTS) will supplement the cementing records, which show an insufficient interval of 80 percent cement bond index or greater through the "B" Shale confining zone. The RTS will demonstrate the presence or absence of adequate cement to prevent fluid movement behind the casing above the uppermost perforation

The Cement Bond Log (CBL) identifies top of cement at 130 feet.

The schematic diagram shows enhanced recovery injection perforations in the Garden Gulch and Douglas Creek Members of the Green River Formation. Additional perforations may be added at a later time between the depths of 3,976 feet and the top of the Wasatch Formation (Estimated to be 6,062 feet) provided the operator first notifies the Director and later submits an updated well completion report (EPA Form 7520-12) and schematic diagram.

The packer will be set no higher than 100 feet above the top perforation.

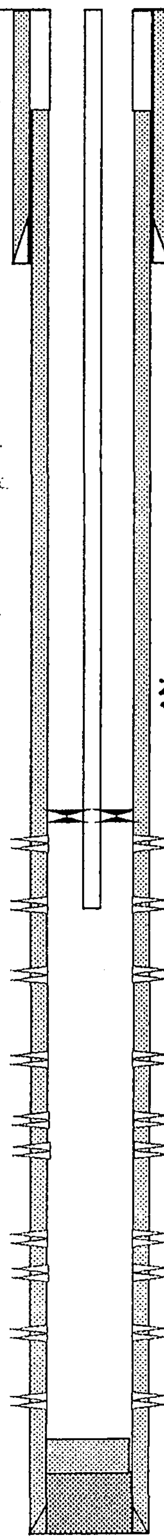
UT 20998-06753

Blackjack Federal 10-5-9-17

Spud Date: 12/1/04
Put on Production: 1/11/05
GL: 5251' KB: 5263'

Proposed Injection
Wellbore Diagram

Initial Production: BOPD,
MCFD, BWPD



SURFACE CASING

CSG SIZE: 8-5/8"
GRADE: J-55
WEIGHT: 24#
LENGTH: 8 jts (323.05')
DEPTH LANDED: 333.05'
HOLE SIZE: 12-1/4"
CEMENT DATA: 160 sxs Class G cement. Est 4 bbls cmt to surface.

Base USDWs 2499'

Green River 1429'

PRODUCTION CASING

CSG SIZE: 5-1/2"
GRADE: J-55
WEIGHT: 15.5# Trona 2852'-2917'
LENGTH: 142 jts. (5988.91') Mahogany 2917-2934'
DEPTH LANDED: 5985.35' KB
HOLE SIZE: 7-7/8"
CEMENT DATA: 350 sxs Premlite II & 400 sxs 50/50 POZ.
CEMENT TOP AT: 130'

Confining Zone 3620'-3674'
Garden Gulch 3674'

TUBING

SIZE/GRADE/WT.: 2-7/8" / J-55 / 6.5# "A" 3786'-3867'
NO. OF JOINTS: 169 jts (5641.19') "B" 3896'-3996
TUBING ANCHOR: 5653.19' KB
NO. OF JOINTS: 1 jt (33.39')
SEATING NIPPLE: 2-7/8" (1.10')
SN LANDED AT: 5689.38' KB
NO. OF JOINTS: 2 jts (66.70')
TOTAL STRING LENGTH: EOT @ 5757.03' w/ 12' KB

Douglas Creek 4648'

3670'-4018': 80% bond

FRAC JOB

1/04/05	5822'-5832'	**Frac CP5 sands as follows:** 18,712# 20/40 sand in 268 bbls Lightning 17 frac fluid. Treated @ avg press of 2130 psi w/avg rate of 24.5 BPM. ISIP 2145 psi. Calc. flush: 5820 gal. Actual flush: 5859 gal.
1/04/05	5542'-5673'	**Frac CP3, 1 & .5 sands as follows:** 64,105# 20/40 sand in 524 bbls Lightning 17 frac fluid. Treated @ avg press of 1956 psi w/avg rate of 24.5 BPM. ISIP 1990 psi. Calc. flush: 5540 gal. Actual flush: 5573 gal.
1/04/05	5300'-5366'	**Frac LODC sands as follows:** 199,147# 20/40 sand in 1337 bbls Lightning 17 frac fluid. Treated @ avg press of 1684 psi w/avg rate of 24.5 BPM. ISIP 2100 psi. Calc. flush: 5298 gal. Actual flush: 5330 gal.
1/04/05	5102'-5112'	**Frac A3 sands as follows:** 44,330# 20/40 sand in 411 bbls Lightning 17 frac fluid. Treated @ avg press of 1968 psi w/avg rate of 24.5 BPM. ISIP 2300 psi. Calc flush: 5100 gal. Actual flush: 5124 gal.
1/05/05	4714'-4724'	**Frac D2 sands as follows:** 19,177# 20/40 sand in 241 bbls Lightning 17 frac fluid. Treated @ avg press of 1791 psi w/avg rate of 24.3 BPM. ISIP 1850 psi. Calc flush: 4712 gal. Actual flush: 4725 gal.
1/05/05	4228'-4238'	**Frac GB6 sands as follows:** 63,938# 20/40 sand in 493 bbls Lightning 17 frac fluid. Treated @ avg press of 2267 psi w/avg rate of 24.5 BPM. ISIP 1780 psi. Calc. flush: 4226 gal. Actual flush: 4259 gal.
1/05/05	4092'-4097'	**Frac GB2 sands as follows:** 14,210# 20/40 sand in 230 bbls Lightning 17 frac fluid. Treated @ avg press of 2447 psi w/avg rate of 24.6 BPM. ISIP 1970 psi. Calc. flush: 4090 gal. Actual flush: 4003 gal.

PERFORATION RECORD

12/30/04	5822'-5832'	4 JSPF	40 holes
01/04/05	5667'-5673'	4 JSPF	24 holes
01/04/05	5580'-5590'	4 JSPF	40 holes
01/04/05	5542'-5550'	4 JSPF	32 holes
01/04/05	5334'-5366'	2 JSPF	64 holes
01/04/05	5300'-5320'	2 JSPF	40 holes
01/04/05	5102'-5112'	4 JSPF	40 holes
01/04/05	4714'-4724'	4 JSPF	40 holes
01/05/05	4228'-4238'	4 JSPF	40 holes
01/05/05	4092'-4097'	4 JSPF	20 holes

5937' Basal Carbonate

Est Wasatch 6062'

NEWFIELD

Blackjack Federal #10-5-9-17
1676' FSL & 1982' FEL
NWSE Section 5-T9S-R17E
Duchesne Co, Utah
API #43-013-32553; Lease #UTU-74808

MC 4/18/05

APPENDIX B

LOGGING AND TESTING REQUIREMENTS

Logs.
Logs will be conducted according to current UIC guidance. It is the responsibility of the Permittee to obtain and use guidance prior to conducting any well logging required as a condition of this permit.

NO LOGGING REQUIREMENTS

Tests.
Tests will be conducted according to current UIC guidance. It is the responsibility of the Permittee to obtain and use guidance prior to conducting any well test required as a condition of this permit.

WELL NAME: Blackjack Federal 10-5-9-17

TYPE OF TEST	DATE DUE
Radioactive Tracer Survey (2)	Within 180 days following commencement of injection. Barring any extraordinary circumstances thgis shall be a one-time event.
Standard Annulus Pressure	Prior to receiving authorization to inject and at least once within any five year period following the last successful test.
Pore Pressure	Prior to receiving authorization to inject.

APPENDIX C

OPERATING REQUIREMENTS

MAXIMUM ALLOWABLE INJECTION PRESSURE:

Maximum Allowable Injection Pressure (MAIP) as measured at the surface shall not exceed the pressure(s) listed below.

WELL NAME	MAXIMUM ALLOWED INJECTION PRESSURE (psi) ZONE 1 (Upper)
Blackjack Federal 10-5-9-17	1,450

INJECTION INTERVAL(S):

Injection is permitted only within the approved injection interval listed below. Injection perforations may be altered provided they remain within the approved injection interval and the Permittee provides notice to the Director in accordance with Part II, Section A, Paragraph 6. Specific injection perforations can be found in Appendix A.

WELL NAME: Blackjack Federal 10-5-9-17

FORMATION NAME	APPROVED INJECTION INTERVAL (KB, ft) TOP	BOTTOM	FRACTURE GRADIENT (psi/ft)
Green River: Garden Gulch-Douglas Creek-Basal Carbonate Members.	3,976.00	6,062.00	0.790

ANNULUS PRESSURE:

The annulus pressure shall be maintained at zero (0) psi as measured at the wellhead. If this pressure cannot be maintained, the Permittee shall follow the procedures listed under Part II, Section C. 6. of this permit.

MAXIMUM INJECTION VOLUME:

There is no limitation on the number of barrels per day (bbls/day) of water that shall be injected into this well, provided further that in no case shall injection pressure exceed that limit shown in Appendix C.

APPENDIX D

MONITORING AND REPORTING PARAMETERS

This is a listing of the parameters required to be observed, recorded, and reported. Refer to the permit Part II, Section D, for detailed requirements for observing, recording, and reporting these parameters.

OBSERVE MONTHLY AND RECORD AT LEAST ONCE EVERY THIRTY DAYS	
OBSERVE AND RECORD	Injection pressure (psig)
	Annulus pressure(s) (psig)
	Injection rate (bbl/day)
	Fluid volume injected since the well began injecting (bbls)

ANNUALLY	
ANALYZE	Injected fluid total dissolved solids (mg/l)
	Injected fluid specific gravity
	Injected fluid specific conductivity
	Injected fluid pH

ANNUALLY	
REPORT	Each month's maximum and averaged injection pressures (psig)
	Each month's maximum and minimum annulus pressure(s) (psig)
	Each month's injected volume (bbl)
	Fluid volume injected since the well began injecting (bbl)
	Written results of annual injected fluid analysis
	Sources of all fluids injected during the year

In addition to these items, additional Logging and Testing results may be required periodically. For a list of those items and their due dates, please refer to APPENDIX B - LOGGING AND TESTING REQUIREMENTS.

APPENDIX E

PLUGGING AND ABANDONMENT REQUIREMENTS

As discussed n EPA Region 8 Guidance, wells should be plugged and abandoned in a manner to prevent migration of fluids in the wellbore intoi or between USDWs. The four (4) cement plugs required for this well are as follows:

PLUG NO. 1: Set a cast iron bridge plug (CIBP) no more than 50 feet above the top perforation with a minimum 20-foot cement plug on top of the CIBP.

Plug No. 1 is required to prevent migration of fluids out of the injection zone. It is believed that there are no USDWs below Plug No. 1.

PLUG NO. 2: Perforate and squeeze cement up the backside of the 5-1/2 inch casing across the Trona Zone and the Mahogany Bench from approximately 2,800 feet 2,985 feet unless pre-existing backside cement precludes cement-squeezing this interval. Set a minimum 185-foot balanced cement plug inside the 5-1/2 inch casing from approximately 2,800 feet 2,985 feet.

Plug No. 2 is required because the interval of the Green River Formation containing the Bird's Nest/Trona Member is reported to contain USDWs in places in the Uinta Basin. The Mahogany Bench Member is an oil shale resource that is protected under U.S. Bureau of Land Mangement (BLM) requirements.

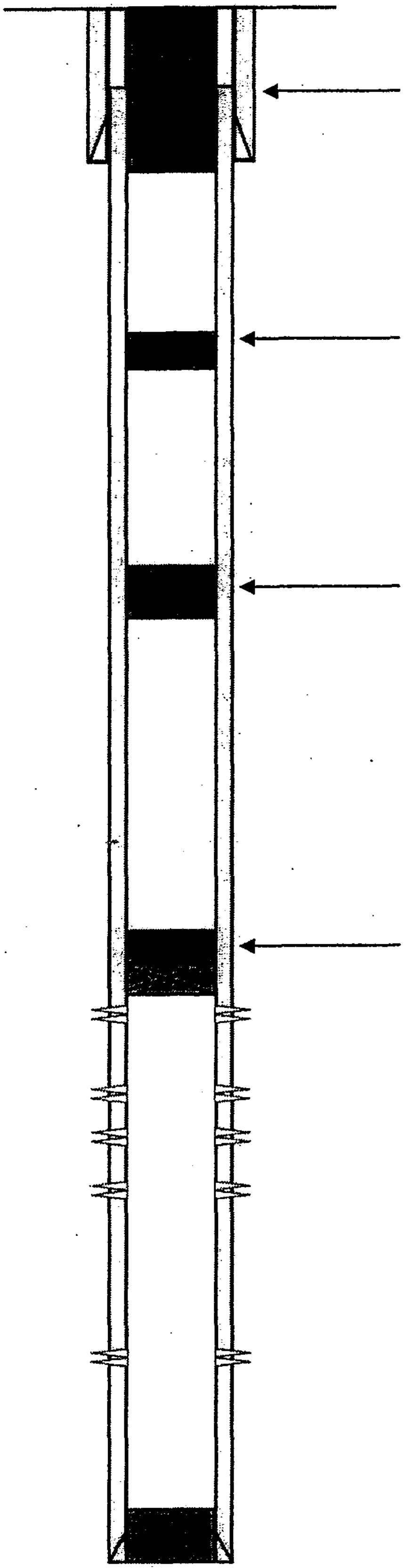
PLUG NO. 3: Perforate and squeeze cement up the backside of the 5-1/2 inch casing across the contact between the Uinta Formation and Green River Formation (1,429 feet) from approximately 1,380 feet - 1,480 feet unless pre-existing backside cement precludes cement-squeezing this interval. Set a minimum 100-foot cement plug inside the 5-1/2 inch casing from approximately 1,380 feet -1,480 feet.

Plug No. 3 is required across the Uinta and Green River Formations contact to prevent flow between USDWs.

PLUG NO. 4: Set a Class "G" cement plug within the 5-1/2 inch casing to 383 feet and up the 5-1/2 inch x 8-5/8 inch casing annulus to the surface.

Plug No. 4 is required to prevent fluids from migrating from the surface or from below into shallow USDWs.

Plugging and Abandonment Diagram
Blackjack Federal 10-5-9-17



Plug 4: Set a Class "G" cement plug within the 5-1/2 inch casing surface to 383 feet and up the 5-1/2 inch X 8-5/8 inch casing annulus to the surface.

Plug 3: Perforate and squeeze cement up the backside of the casing across the contact between the Uinta Formation and Green River Formation, 1,380 feet - 1,440 feet, unless existing backside cement precludes cement-squeezing this interval. Set a minimum 100-foot balanced cement plug inside the casing from approximately 1,380 feet – 1,480 feet.

Plug 2: Perforate and squeeze cement up the backside of the casing across the Trona Zone and Mahogany Bench from approximately 2,600 feet – 2,760 feet unless pre-existing backside cement precludes cement-squeezing this interval. Set a minimum 160-foot balanced cement plug inside of the casing approximately 2,600 feet – 2,760 feet.

Plug 1: Set a cast iron bridge plug (CIBP) no more than 50 ft above the top perforation with a minimum of 20 ft cement plug on top of the CIBP.

APPENDIX F

CORRECTIVE ACTION REQUIREMENTS

Blackjack Federal 9-5R-9-17 and Balcron Monument Federal 23-5J-9-17 shall be monitored weekly at the surface for evidence of fluid movement out of the injection zone.

Newfield developed a corrective action monitoring program, effective July 10, 2008, entitled "Procedure related to proposed Class II Enhanced Oil Recovery Injection Wells determined by the EPA to have specific Area of Review (AOR) wells with inadequate cement across the Confining Zone".

If possible fluid movement out of the injection zone is identified, either through the weekly monitoring, through Newfield's July 10, 2008 procedure described above, or through any other means (for example, evidence of fluid flow or increased bradenhead annulus pressure readings, tubing-casing annulus pressure readings, or other evidence of a mechanical integrity failure), Permittee will shut in Blackjack Federal 10-5-9-17 immediately and notify the Director. No injection into Blackjack Federal 10-5-9-17 will be permitted until Permittee has notfied the Director that the situation has been resolved, submitted Rework Records (EPA Form No. 7520-12) and a schematic diagram, and received authorization from the Director to re-commence injection.

NEWFIELD

ROCKY MOUNTAINS

RE: Procedure related to proposed Class II Enhanced Oil Recovery Injection Wells determined by the EPA to have specific Area of Review (AOR) wells with inadequate cement across the confining zone

Effective July 10, 2008 Newfield Production Company will implement the following procedure to address concerns related to protection of Underground Sources of Drinking Water (USDW) in AOR wells where the interval of cement bond index across the confining zone behind pipe has been determined to be inadequate. The procedure is intended to meet the corrective action requirements found in the UIC Class II permit, as well as provide data that could be used to detect and prevent fluid movement out of the proposed injection zone.

1) Establish baseline production casing by surface casing annulus pressures prior to water injection in subject well with a calibrated gauge.
2) Record the baseline pressure, report findings to Newfield engineering group and keep on file so it is available upon request
3) Place injection well in service. Run packer integrity and radioactive tracer logs to verify wellbore integrity and determine zones taking water.
4) Construct a geologic cross section showing zones taking water and their geologic equivalent zones in the AOR wells.
5) Submit a report of the packer integrity log, radioactive tracer log, and geologic cross section to to the Newfield engineering staff for review and keep on file so it is available upon request
6) Weekly observations of the site will be made by Newfield during normal well operating activities. Any surface discharge of fluids will be reported immediately.
7) After injection well is placed in service, weekly observations of annulus pressure will be made and compared to baseline pressure and will be recorded once monthly. The recorded pressure information will be kept on file and be available upon request.
8) If pressure increases by more than 10% above baseline at any time in an AOR well with insufficient cement bond, Newfield will run a temperature survey log in subject well. This log, in concert with the geologic crossection, will enable the determination of water movement in the open hole by production casing annulus through a shift in geothermal gradient.
9) If water movement is determined in annulus, Newfield will shut in the injection well and repair the production casing by open hole annulus or leave the injection well out of service.

STATEMENT OF BASIS

NEWFIELD PRODUCTION CO.
BLACKJACK FEDERAL 10-5-9-17
DUCHESNE COUNTY, UT

EPA PERMIT NO. UT20998-06753

CONTACT: Emmett Schmitz
U. S. Environmental Protection Agency
Ground Water Program, 8P-W-GW
1595 Wynkoop Street
Denver, Colorado 80202-1129
Telephone: 1-800-227-8917 ext. 312-6174

This STATEMENT OF BASIS gives the derivation of site-specific UIC Permit conditions and reasons for them. Referenced sections and conditions correspond to sections and conditions in the Permit.

EPA UIC permits regulate the injection of fluids into underground injection wells so that the injection does not endanger underground sources of drinking water. EPA UIC permit conditions are based upon the authorities set forth in regulatory provisions at 40 CFR Parts 144 and 146, and address potential impacts to underground sources of drinking water. Under 40 CFR 144.35 Issuance of this permit does not convey any property rights of any sort or any exclusive privilege, nor authorize injury to persons or property of invasion of other private rights, or any infringement of other Federal, State or local laws or regulations. Under 40 CFR 144 Subpart D, certain conditions apply to all UIC Permits and may be incorporated either expressly or by reference. General Permit conditions for which the content is mandatory and not subject to site-specific differences (40 CFR Parts 144, 146 and 147) are not discussed in this document.

Upon the Effective Date when issued, the Permit authorizes the construction and operation of injection wells so that the injection does not endanger underground sources of drinking water, governed by the conditions specified in the Permit. The Permit is issued for the operating life of the injection well or project unless terminated for reasonable cause under 40 CFR 144.39, 144.40 and 144.41. The Permit is subject to EPA review at least once every five (5) years to determine if action is required under 40 CFR 144.36(a).

PART I. General Information and Description of Facility

Newfield Production Co. 1001 Seventeenth Street, Suite 2000 Denver, CO 80202

on

April 26, 2005

submitted an application for an Underground Injection Control (UIC) Program Permit or Permit Modification for the following injection well or wells:

Blackjack Federal 10-5-9-17 1676' FSL 1982' FEL, NWSE S5, T9S, R17E Duchesne County, UT

Regulations specific to Uintah-Ouray Indian Reservation injection wells are found at 40 CFR 147 Subpart TT.

The application, including the required information and data necessary to issue or modify a UIC Permit in accordance with 40 CFR Parts 144, 146 and 147, was reviewed and determined by EPA to be complete.

The Permit will expire upon delegation of primary enforcement responsibility (primacy) for applicable portions of the UIC Program to the Ute Indian Tribe or the State of Utah unless the delegated agency has the authority and chooses to adopt and enforce this Permit as a Tribal or State Permit.

TABLE 1.1 shows the status of the well or wells as "New", "Existing", or "Conversion" and for Existing shows the original date of injection operation. Well authorization "by rule" under 40 CFR Part 144 Subpart C expires automatically on the Effective Date of an issued UIC Permit.

Blackjack Federal 10-5-9-17 is currently an active oil well producing from the Garden Gulch-Douglas Creek Members of the Green River Formation. It is the applicants initial intent to use existing production perforations for enhanced recovery injection.

TABLE 1.1

WELL STATUS / DATE OF OPERATION

NEW WELLS

Well Name	Well Status	Date of Operation
Blackjack Federal 10-5-9-17	New	N/A

PART II. Permit Considerations (40 CFR 146.24)

Hydrogeologic Setting

Water wells for domestic supply in this area, when present, generally are completed into the shallow alluvium, the Duchesne River Formation, or the underlying Uinta Formation, and the water generally contains approximately 500 to 1,500 mg/l and higher total dissolved solids.

The Uinta-Animas aquifer in the Uinta Basin is present in water-yielding beds of sandstone, conglomerate, and siltstone of the Duchesne River and Uinta Formations, the Renegade Tongue of the Wasatch Formation, and the Douglas Creek Member of the Green River Formation. The Renegade Tongue of the Wasatch Formation and the Douglas Creek Member of the Green River Formation contain an aquifer along the southern and eastern margins of the basin where the rocks primarily consist of fluvial, massive, irregularly bedded sandstone and siltstone. Water-yielding units in the Uinta-Animas aquifer in the Uinta Basin commonly are separated from each other and from the underlying Mesaverde aquifer by units of low permeability composed of claystone, shale, marlstone, or limestone. In the Uinta Basin, for example, the part of the aquifer in the Duchesne River and Uinta Formations ranges in thickness from 0 feet at the southern margin of the aquifer to as much as 9,000 feet in the north-central part of the aquifer. Ground-water recharge to the Uinta-Animas aquifer generally occurs in the areas of higher altitude along the margins of the basin. Ground water is discharged mainly to streams, springs, and by transpiration from vegetation growing along stream valleys. The rate of ground-water withdrawal is small, and natural discharge is approximately equal to recharge. Recharge occurs near the southern margin of the aquifer, and discharge occurs near the White and Green Rivers (from USGS publication HA 730-C). Water samples from Mesaverde sands in the nearby Natural Buttes Unit yielded highly saline water.

Geologic Setting (TABLE 2.1)

The proposed enhanced oil recovery injection well is located in the Greater Monument Butte Field, T7-9S and R15-19E, which lies near the center of the broad, gently northward dipping south flank of the Uinta Basin. More than 450 million barrels of oil (63 MT) have been produced from sediments of the Uinta Basin. The Uinta Basin is a topographic and structural trough encompassing an area of more than 9,300 square mi (14,900 km) in northeast Utah. The basin is sharply asymmetrical, with a steep north flank bounded by the east-west-trending Uinta Mountains, and a gently dipping south flank. The Uinta Basin was formed in Paleocene to Eocene time, creating a large area of internal drainage which was filled by the ancestral Lake Uinta. The lacustrine, or fresh water lake-formed, sediments deposited in and around Lake Uinta make up the Uintah and Green River Formations. The southern shore of Lake Uinta was very broad and flat, resulting in large cyclic shifts of the location of the shoreline during the many repeated transgressive and regressive cycles caused by the climatic and tectonic-induced rise and fall of water levels of the lake. Distributary-mouth bars, distributary channels, and near-shore bars are the primary oil producing sandstone reservoirs in the area. (Ref: "Reservoir Characterization of the Lower Green River Formation, Southwest Uinta Basin, Utah Biannual Technical Progress Report, 4/1/99-9/30/99", by C. D. Morgan, Program Manager, November 1999, Contract DE-AC26-98BC15103).

The Duchesne River Formation is absent in this area. Shale and siltstone of the Uintah Formation outcrop and compose the surface rock throughout the area. The lower 600 feet to 800 feet of the Uinta Formation, consisting generally of shale interbedded with occasionally water-bearing sandstone lenses between 5 feet to 20 feet thick, is underlain by the Green River Formation. The Green River Formation is further subdivided into several Member and local marker units. The cyclic nature of Green River deposition in the southern shore area resulted in numerous stacked, intertonguing deltaic and near-shore sand and silt deposits. Red alluvial shale and siltstone deposits that intertongue with the Green River sediments are of the Colton and Wasatch Formations. Under the Wasatch Formation is the Mesaverde Formation, which consists primarily of continental-origin deposits of interbedded shale, sandstone, and coal.

The geologic dip is about 200 feet per mile, and there are no known surface faults in this area. Veins of gilsonite, a natural resinous hydrocarbon occasionally mined as a resource, occurs in the greater Uintah Basin though it is predominantly found on the eastern margin of the basin near the Colorado border. Vertical veins, generally between 2 feet to 6 feet wide but up to 28 feet wide, may extend many miles in length and occasionally extend as deep as 2,000 feet. In this area within the Greater Monument Butte Field there is one known gilsonite vein. This vein is not considered to present a pathway for migration of fluid out of the injection zone because it terminates at depth of about 2,000 ft, far above the protective confining layer and much deeper injection zone.

TABLE 2.1
GEOLOGIC SETTING
Blackjack Federal 10-5-9-17

Formation Name	Top (ft)	Base (ft)	TDS (mg/l)	Lithology
Uinta: Public. 92	0	249	< 10,000	Sand and shale.
Uinta	0	1,421	< 10,000	Sand and shale.
Green River	1,429	6,062		Interbedded lacustrine sand, shale, carbonate and evaporite with some fluvial sand and shale.
Green River: Trona	2,852	2,917		Evaporite
Green River: Mahogany Bench	2,917	2,934		Oil shale
Green River: Garden Gulch Member	3,674	4,648	19,369	Interbedded lacustrine sand, shale and carbonate with some fluvial sand and shale.
Green River: "B" Shale Confining Zone	3,896	3,976		Shale
Green River: Douglas Creek Member	4,648	5,937	19,369	Interbedded lacustrine sand, shale and carbonate with some fluvial sand and shale.
Green River: Basal Carbonate Member	5,937	6,062		Carbonate

Proposed Injection Zone(s) (TABLE 2.2)

An injection zone is a geological formation, group of formations, or part of a formation that receives fluids through a well. The proposed injection zones are listed in TABLE 2.2.

Injection will occur into an injection zone that is separated from USDWs by a confining zone which is free of known open faults or fractures within the Area of Review.

The approved interval for Class II enhanced recovery injection is located between the top of the Garden Gulch Member No. 2 (3,976 feet) and the top of the Wasatch Formation which is estimated to be 6,062 feet.

TABLE 2.2
INJECTION ZONES
Blackjack Federal 10-5-9-17

Formation Name	Top (ft)	Base (ft)	TDS (mg/l)	Fracture Gradient (psi/ft)	Porosity	Exempted?*
Green River: Garden Gulch-Douglas Creek-Basal Carbonate Members.	3,976	6,062	19,369	0.790		N/A

*** C - Currently Exempted**
E - Previously Exempted
P - Proposed Exemption
N/A - Not Applicable

Confining Zone(s) (TABLE 2.3)
A confining zone is a geological formation, part of a formation, or a group of formations that limits fluid movement above the injection zone. The confining zone or zones are listed in TABLE 2.3.

The Garden Gulch Member "B" Shale Confining Zone is located between the depths of 3,896 feet and 3,976 feet.

TABLE 2.3
CONFINING ZONES
Blackjack Federal 10-5-9-17

Formation Name	Formation Lithology	Top (ft)	Base (ft)
Green River: Garden Gulch Member "B" Shale.	Shale	3,896	3,976

Underground Sources of Drinking Water (USDWs) (TABLE 2.4)
Aquifers or the portions thereof which contain less than 10,000 mg/l total dissolved solids (TDS) and are being or could in the future be used as a source of drinking water are considered to be USDWs. The USDWs in the area of this facility are identified in TABLE 2.4.

The State of Utah "Water Wells and Springs", http//NRWRT1.STATE.UT.US, identifies no public water supply wells within the one-quarter (1/4) mile Area-of-Review (AOR) around Blackjack Federal 10-5-9-17.

Technical Publication No. 92: State of Utah, Department of Natural Resources, cites the base of Underground Sources of Drinking Water (USDWs) in the Uinta Formation approximately 249 feet from the surface.

TABLE 2.4
UNDERGROUND SOURCES OF DRINKING WATER (USDW)
Blackjack Federal 10-5-9-17

Formation Name	Formation Lithology	Top (ft)	Base (ft)	TDS (mg/l)
Uinta	Sand and shale.	0	1,429	< 10,000
Uinta: Public. 92	Sand and shale.	0	249	< 10,000

PART III. Well Construction (40 CFR 146.22)

See diagram.

Blackjack Federal 10-5-9-17 was drilled to a total depth of 6,015 feet (KB) feet in the Basal Carbonate Member of the Green River Formation.

Surface casing (8-5/8 inch) was set at a depth of 333 feet in a 12-1/4 inch hole using 160 sacks of Class "G" cement which was circulated to the surface.

Production casing (5-1/2 inch) was set at a depth of 5,985 feet (KB) in a 7-7/8 inch hole with 350 sacks of Premium Lite II and 400 sacks of 50/50 poz mix. The Shale "B" Confining Zone is absent 80% bond index cement.

A Radioactive Tracer Survey (RTS) will supplement the cementing records, which show an insufficient interval of 80 percent cement bond index or greater through the "B" Shale confining zone. The RTS will demonstrate the presence or absence of adequate cement to prevent fluid movement behind the casing above the uppermost perforation.

The Cement Bond Log (CBL) identifies top of cement at 130 feet.

The schematic diagram shows enhanced recovery injection perforations in the Garden Gulch and Douglas Creek Members of the Green River Formation. Additional perforations may be added at a later time between the depths of 3,976 feet and the top of the Wasatch Formation (Estimated to be 6,062 feet) provided the operator first notifies the Director and later submits an updated well completion report (EPA Form 7520-12) and schematic diagram.

The packer will be set no higher than 100 feet above the top perforation.

TABLE 3.1
WELL CONSTRUCTION REQUIREMENTS
Blackjack Federal 10-5-9-17

Casing Type	Hole Size (in)	Casing Size (in)	Cased Interval (ft)	Cemented Interval (ft)
Production	7.88	5.50	0 - 5,985	130 - 6,015
Surface	12.25	8.63	0 - 333	0 - 333

The approved well completion plan will be incorporated into the Permit as APPENDIX A and will be binding on the Permittee. Modification of the approved plan is allowed under 40 CFR 144.52(a)(1) provided written approval is obtained from the Director prior to actual modification.

Casing and Cementing (TABLE 3.1)

The well construction plan was evaluated and determined to be in conformance with standard practices and guidelines that ensure well injection does not result in the movement of fluids into USDWs. Well construction details for this "new" injection well is shown in TABLE 3.1.

Remedial cementing may be required if the casing cement is shown to be inadequate by cement bond log or other demonstration of Part II (External) mechanical integrity.

Tubing and Packer

Injection tubing is required to be installed from a packer up to the surface inside the well casing. The packer will be set above the uppermost perforation. The tubing and packer are designed to prevent injection fluid from coming into contact with the outermost casing.

Tubing-Casing Annulus (TCA)

The TCA allows the casing, tubing and packer to be pressure-tested periodically for mechanical integrity, and will allow for detection of leaks. The TCA will be filled with fresh water treated with a corrosion inhibitor or other fluid approved by the Director.

The tubing/casing annulus must be kept open at all times so that it can be monitored as required under the Permit.

Monitoring Devices

The permittee will be required to install and maintain wellhead equipment that allows for monitoring pressures and providing access for sampling the injected fluid. Required equipment may include but is not limited to: 1) shut-off valves located at the wellhead on the injection tubing and on the TCA; 2) a flow meter that measures the cumulative volume of injected fluid; 3) fittings or pressure gauges attached to the injection tubing and the TCA for monitoring the injection and TCA pressure; and 4) a tap on the injection line, isolated by shut-off valves, for sampling the injected fluid.

All sampling and measurement taken for monitoring must be representative of the monitored activity.

PART IV. Area of Review, Corrective Action Plan (40 CFR 144.55)

TABLE 4.1
AOR AND CORRECTIVE ACTION

Well Name	Type	Status (Abandoned Y/N)	Total Depth (ft)	TOC Depth (ft)	CAP Required (Y/N)
Allen Federal 43-5-9-17	Other	Yes	5,890	5,889	No
Balcron Monument Fed 23-5J-9-17	Injector	No	5,773	3,100	Yes
Blackjack Federal 9-5R-9-17	Producer	No	5,890	700	Yes
Federal 34-5H-9-17	Other	No	6,067	940	No
Monument Federal 24-5-9-17	Injector	No	5,700	1,645	No

TABLE 4.1 lists the wells in the Area of Review ("AOR") and shows the well type, operating status, depth, top of casing cement ("TOC") and whether a Corrective Action Plan ("CAP") is required for the well.

Area Of Review

Applicants for Class I, II (other than "existing" wells) or III injection well Permits are required to identify the location of all known wells within the injection well's Area of Review (AOR) which penetrate the injection zone, or in the case of Class II wells operating over the fracture pressure of the formation, all known wells within the area of review that penetrate formations which may be affected by increased pressure. Under 40 CFR 146.6 the AOR may be a fixed radius of not less than one quarter (1/4) mile or a calculated zone of endangering influence. For Area Permits, a fixed width of not less than one quarter (1/4) mile for the circumscribing area may be used.

Corrective Action Plan

For wells in the AOR which are improperly sealed, completed, or abandoned, the applicant shall develop a Corrective Action Plan (CAP) consisting of the steps or modifications that are necessary to prevent movement of fluid into USDWs.

The CAP will be incorporated into the Permit as APPENDIX F and become binding on the permittee.

PART V. Well Operation Requirements (40 CFR 146.23)

TABLE 5.1 INJECTION ZONE PRESSURES Blackjack Federal 10-5-9-17			
Formation Name	**Depth Used to Calculate MAIP (ft)**	**Fracture Gradient (psi/ft)**	**Initial MAIP (psi)**
Green River: Garden Gulch-Douglas Creek-Basal Carbonate Members.	4,092	0.790	1,430

Approved Injection Fluid

The approved injection fluid is limited to Class II injection well fluids pursuant to 40 CFR § 144.6(b). For disposal wells injecting water brought to the surface in connection with natural gas storage operations, or conventional oil or natural gas production, the fluid may be commingled and the well used to inject other Class II wastes such as drilling fluids and spent well completion, treatment and stimulation fluid. Injection of non-exempt wastes, including unused fracturing fluids or acids, gas plant cooling tower cleaning wastes, service wastes, and vacuum truck and drum rinsate from trucks and drums transporting or containing non-exempt waste, is prohibited.

The proposed injectate is primarily fluid from the Johnson Water District pipeline and/or water from the Green River pipeline blended with produced Green River Formation water from wells proximate to the Blackjack Federal 10-5-9-17.

Injection Pressure Limitation

Injection pressure, measured at the wellhead, shall not exceed a maximum calculated to assure that the pressure used during injection does not initiate new fractures or propagate existing fractures in the confining zones adjacent to the USDWs.

The applicant submitted injection fluid density and injection zone data which was used to calculate a formation fracture pressure and to determine the maximum allowable injection pressure (MAIP), as measured at the surface, for this Permit.

TABLE 5.1 lists the fracture gradient for the injection zone and the approved MAIP, determined according to the following formula:

$$FP = [fg - (0.433 * sg)] * d$$

FP = formation fracture pressure (measured at surface)
fg = fracture gradient (from submitted data or tests)
sg = specific gravity (of injected fluid)
d = depth to top of injection zone (or top perforation)

Injection Volume Limitation

Cumulative injected fluid volume limits are set to assure that injected fluids remain within the boundary of the exempted area. Cumulative injected fluid volume is limited when injection occurs into an aquifer that has been exempted from protection as a USDW.

There will be no restrictions on the cumulative volume of authorized fluid injected into the Green

River interval 3,976 feet to the top of the Wasatch Formation which is estimated to be 6,062 feet.

Mechanical Integrity (40 CFR 146.8)

An injection well has mechanical integrity if:

1. there is no significant leak in the casing, tubing, or packer (Part I); and
2. there is no significant fluid movement into a USDW through vertical channels adjacent to the injection well bore (Part II).

The Permit prohibits injection into a well which lacks mechanical integrity.

The Permit requires that the well demonstrate mechanical integrity prior to injection and periodically thereafter. A demonstration of mechanical integrity includes both internal (Part I) and external (Part II). The methods and frequency for demonstrating Part I and Part II mechanical integrity are dependent upon well-specific conditions as explained below.

Well construction and site-specific conditions dictate the following requirements for Mechanical Integrity (MI) demonstrations:

PART I MI: Internal MI will be demonstrated prior to beginning injection. Since this well is constructed with a standard casing, tubing, and packer configuration, a successful mechanical integrity test (MIT) is required to take place at least once every five (5) years. A demonstration of Part I MI is also required prior to resuming injection following any workover operation that affects the casing, tubing or packer. Part I MI may be demonstrated by a standard tubing-casing annulus pressure test using the maximum permitted injection pressure or 1000 psi, which ever is less, with a ten (10) percent or less pressure loss over thirty (30) minutes.

PART II MI: The RTS will supplement the cementing records, which show an insufficient interval of 80 percent cement bond index or greater through the "B" Shale confining zone, by demonstrating the presence or absence of adequate cement to prevent fluid movement behind the casing above the uppermost perforation. It is intended that a maximum of 180 days of injection will allow the injection zone to achieve the Maximum Allowable Injection Pressure (MAIP) for the purpose of executing the RTS. If 180 days is not sufficient to achieve the MAIP specified in the Permit, an extension of the period of Limited Authorization to Inject may be requested. A submitted RTS which indicates the movement of fluid behind casing from the injection zone will result in a requirement to demonstrate Part II Mechanical Integrity using an approved Part II demonstration method such as a temperature log, oxygen activation log, or noise log at a frequency no less than once every five years.

PART VI. Monitoring, Recordkeeping and Reporting Requirements

Injection Well Monitoring Program

At least once a year the permittee must analyze a sample of the injected fluid for total dissolved solids (TDS), specific conductivity, pH, and specific gravity. This analysis shall be reported to EPA annually as part of the Annual Report to the Director. Any time a new source of injected fluid is added, a fluid analysis shall be made of the new source.

Instantaneous injection pressure, injection flow rate, cumulative fluid volume and TCA pressures must be observed on a weekly basis. A recording, at least once every thirty (30) days, must be made of the injection pressure, annulus pressure, monthly injection flow rate and cumulative fluid volume. This information is required to be reported annually as part of the Annual Report to the Director.

PART VII. Plugging and Abandonment Requirements (40 CFR 146.10)

As discussed n EPA Region 8 Guidance, wells should be plugged and abandoned in a manner to prevent migration of fluids in the wellbore intoi or between USDWs. The four (4) cement plugs required for this well are as follows:

PLUG NO. 1: Set a cast iron bridge plug (CIBP) no more than 50 feet above the top perforation with a minimum 20-foot cement plug on top of the CIBP.

Plug No. 1 is required to prevent migration of fluids out of the injection zone. It is believed that there are no USDWs below Plug No. 1.

PLUG NO. 2: Perforate and squeeze cement up the backside of the 5-1/2 inch casing across the Trona Zone and the Mahogany Bench from approximately 2,800 feet 2,985 feet unless pre-existing backside cement precludes cement-squeezing this interval. Set a minimum 185-foot balanced cement plug inside the 5-1/2 inch casing from approximately 2,800 feet 2,985 feet.

Plug No. 2 is required because the interval of the Green River Formation containing the Bird's Nest/Trona Member is reported to contain USDWs in places in the Uinta Basis. The Mahogany Bench Member is an oil shale resource that is protected under U.S. Bureau of Land Mangement (BLM) requirements.

PLUG NO. 3: Perforate and squeeze cement up the backside of the 5-1/2 inch casing across the contact between the Uinta Formation and Green River Formation (1,429 feet) from approximately 1,380 feet - 1,480 feet unless pre-existing backside cement precludes cement-squeezing this interval. Set a minimum 100-foot cement plug inside the 5-1/2 inch casing from approximately 1,380 feet -1,480 feet.

Plug No. 3 is rquired across the Uinta and Green River Formations contact to prevent flow between USDWS.

PLUG NO. 4: Set a Class “G” cement plug within the 5-1/2 inch casing to 383 feet and up the 5-1/2 inch x 8-5/8 inch casing annulus to the surface.

Plug No. 4 is required to prevent fluids from migrating from the surface or from below into shallow USDWs.

Plugging and Abandonment Plan

Prior to abandonment, the well shall be plugged in a manner that isolates the injection zone and prevents movement of fluid into or between USDWs, and in accordance with any applicable Federal, State or local law or regulation. Tubing, packer and other downhole apparatus shall be removed. Cement with additives such as accelerators and retarders that control or enhance cement properties may be used for plugs; however, volume-extending additives and gel cements are not approved for plug use. Plug placement shall be verified by tagging. Plugging gel of at least 9.2 lb/gal shall be placed between all plugs. A minimum 50 ft surface plug shall be set inside and outside of the surface casing to seal pathways for fluid migration into the subsurface. Within sixty (60) days after plugging the owner or operator shall submit Plugging Record (EPA Form 7520 13) to the Director. The Plugging Record must be certified as accurate and complete by the person responsible for the plugging operation. The plugging and abandonment plan is described in Appendix E of the Permit.

PART VIII. Financial Responsibility (40 CFR 144.52)

Demonstration of Financial Responsibility

The permittee is required to maintain financial responsibility and resources to close, plug, and abandon the underground injection operation in a manner prescribed by the Director. The permittee shall show evidence of such financial responsibility to the Director by the submission of a surety bond, or other adequate assurance such as financial statements or other materials acceptable to the Director. The Regional Administrator may, on a periodic basis, require the holder of a lifetime permit to submit a revised estimate of the resources needed to plug and abandon the well to reflect inflation of such costs, and a revised demonstration of financial responsibility if necessary. Initially, the operator has chosen to demonstrate financial responsibility with:

A demonstration of Financial Responsibility in the amount of $59,344 has been reviewed and approved by the EPA. The Director may revise the amount required, and may require Permittee to obtain and provide updated estimates of plugging and abandonment costs according to the approved Plugging and Abandonment Plan.

Financial Statement, received April 22, 2005

Evidence of continuing financial responsibility is required to be submitted to the Director annually.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 8
1595 WYNKOOP STREET
DENVER, CO 80202-1129
http://www.epa.gov/region8

AUG 20 2012

Ref: 8P-W-UIC

CERTIFIED MAIL
RETURN RECEIPT REQUESTED

RECEIVED
AUG 29 2012
DIV. OF OIL, GAS & MINING

Eric Sundberg
Newfield Production Company
1001 Seventeenth Street, Suite 2000
Denver, Colorado 80202

Accepted by the
Utah Division of
Oil, Gas and Mining
FOR RECORD ONLY

Re: FINAL Permit
EPA UIC Permit UT22228-09492
Well: Blackjack Federal 10-5-9-17
NWSE Sec. 5-T9S-R17E
Duchesne County, Utah
API No.: 4301332553

Dear Mr. Sundberg:

Enclosed is your copy of the FINAL Underground Injection Control (UIC) Program Permit for the proposed Blackjack Federal 10-5-9-17 injection well. A Statement of Basis that discusses the conditions and requirements of this Environmental Protection Agency (EPA) UIC Permit, is also included.

The public comment period for this permit ended on AUG 10 2012. No comments on the draft permit were received during the public notice period; therefore the effective date for this EPA UIC Permit is the date of issuance. All conditions set forth herein refer to Title 40 Parts 124, 144, 146, and 147 of the Code of Federal Regulations (CFR) and are regulations that are in effect as of the Effective Date of this Permit.

Please note that under the terms and conditions of this final permit you are authorized only to construct the proposed injection well. Prior to commencing injection, you first must fulfill all "Prior to Commencing Injection" requirements of the final permit, Part II Section C.1, and obtain written Authorization to Inject from EPA. It is your responsibility to be familiar with and to comply with all provisions of your final permit. The EPA forms referenced in the permit are available at http://www.epa.gov/safewater/uic/reportingforms.html. Guidance documents for Cement Bond Logging, Radioactive Tracer Testing, Step Rate Testing, Mechanical Integrity Demonstration, Procedure in the Event of a Mechanical Integrity Loss, and other UIC guidances, are available at http://www.epa.gov/region8/water/uic/ deep_injection.html. Upon request, hard copies of the EPA forms and guidances can be provided.

This EPA UIC permit is issued for the operating life of the well unless terminated (Part III, Section B). The EPA may review this permit at least every five (5) years to determine whether any action is warranted pursuant to 40 CFR § 144.36(a).

If you have any questions on the enclosed final permit or Statement of Basis, please call Emmett Schmitz of my staff at (303) 312-6174, or toll-free at (800) 227-8917, ext. 312-6174.

Sincerely,

for

Callie A. Videtich
Acting Assistant Regional Administrator
Office of Partnerships and Regulatory Assistance

enclosure: Final UIC Permit
Statement of Basis

cc: Letter Only:
Uintah & Ouray Business Committee:
Irene Cuch, Chairman
Ronald Wopsock, Vice-Chairman
Frances Poowegup, Councilwoman
Phillip Chimburas, Councikman
Stewart Pike, Councilman
Richards Jenks, Jr., Councilman

Johnna Blackhair
BIA - Uintah & Ouray Indian Agency

cc: All Enclosures:

Reed Durfey
District Manager
Newfield Production Company
Myton, Utah

Mike Natchees
Environmantal Coordinator
Ute Indian Tribe

Manual Myore
Director of Energy & Minerals Dept.

Brad Hill
Acting Associate Director
Utah Division of Oil, Gas, and Mining

Fluid Minerals Engineering Office
BLM - Vernal, Utah Office

UNDERGROUND INJECTION CONTROL PROGRAM

PERMIT

PREPARED: August 2012

Permit No. UT22228-09492

Class II Enhanced Oil Recovery Injection Well

Blackjack Federal 10-5-9-17
Duchesne County, UT

Issued To

Newfield Production Co.
1001 Seventeenth Street, Suite 2000
Denver, CO 80202

Part I. AUTHORIZATION TO CONSTRUCT AND OPERATE

Under the authority of the Safe Drinking Water Act and Underground Injection Control (UIC) Program regulations of the U. S. Environmental Protection Agency (EPA) codified at Title 40 of the Code of Federal Regulations (40 CFR) Parts 2, 124, 144, 146, and 147, and according to the terms of this Permit,

Newfield Production Co.
1001 Seventeenth Street, Suite 2000
Denver, CO 80202

is authorized to construct and to operate the following Class II injection well or wells:

Blackjack Federal 10-5-9-17
1676' FSL & 1982' FEL, NWSE S5, T9S, R17E
Duchesne County, UT

EPA regulates the injection of fluids into injection wells so that injection does not endanger underground sources of drinking water (USDWs). EPA UIC Permit conditions are based on authorities set forth at 40 CFR Parts 144 and 146, and address potential impacts to USDWs.

Under 40 CFR Part 144, Subpart D, certain conditions apply to all UIC Permits and may be incorporated either expressly or by reference. General permit conditions for which the content is mandatory and not subject to site-specific differences are not discussed in this document. Issuance of this Permit does not convey any property rights of any sort or any exclusive privilege, nor does it authorize injury to persons or property or invasion of other private rights, or any infringement of other Federal, State or local laws or regulations. (40 CFR §144.35) An EPA UIC Permit may be issued for the operating life of the injection well or project unless terminated for reasonable cause under 40 CFR §144.39, 144.40 and 144.41, and may be reviewed at least once every five (5) years to determine if action is required under 40 CFR §144.36(a).

This Permit is issued for the life of the well(s) unless modified, revoked and reissued, or terminated under 40 CFR §144.39 or 144.40. This EPA Permit may be adopted, modified, revoked and reissued, or terminated if primary enforcement authority for a UIC Program is delegated to an Indian Tribe or State. Upon the effective date of delegation, reports, notifications, questions and other correspondence should be directed to the Indian Tribe or State Director.

Issue Date: AUG 20 2012 Effective Date AUG 20 2012

Callie A. Videtich
Acting Assistant Regional Administrator*
Office of Partnerships and Regulatory Assistance

*NOTE: The person holding this title is referred to as the "Director" throughout this Permit.

PART II. SPECIFIC PERMIT CONDITIONS

Section A. WELL CONSTRUCTION REQUIREMENTS

These requirements represent the approved minimum construction standards for well casing and cement, injection tubing, and packer.

Details of the approved well construction plan are incorporated into this Permit as APPENDIX A. Changes to the approved plan that may occur during construction must be approved by the Director prior to being physically incorporated.

1. Casing and Cement.

The well or wells shall be cased and cemented to prevent the movement of fluids into or between underground sources of drinking water. The well casing and cement shall be designed for the life expectancy of the well and of the grade and size shown in APPENDIX A. Remedial cementing may be required if shown to be inadequate by cement bond log or other attempted demonstration of Part II (External) mechanical integrity.

2. Injection Tubing and Packer.

Injection tubing is required, and shall be run and set with a packer at or below the depth indicated in APPENDIX A. The packer setting depth may be changed provided it remains below the depth indicated in APPENDIX A and the Permittee provides notice and obtains the Director's approval for the change.

3. Sampling and Monitoring Devices.

The Permittee shall install and maintain in good operating condition:

(a) a "tap" at a conveniently accessible location on the injection flow line between the pump house or storage tanks and the injection well, isolated by shut-off valves, for collection of representative samples of the injected fluid; and

(b) one-half (1/2) inch female iron pipe fitting, isolated by shut-off valves and located at the wellhead at a conveniently accessible location, for the attachment of a pressure gauge capable of monitoring pressures ranging from normal operating pressures up to the Maximum Allowable Injection Pressure specified in APPENDIX C:

  (i) on the injection tubing; and

  (ii) on the tubing-casing annulus (TCA); and

(c) a pressure actuated shut-off device attached to the injection flow line set to shut-off the injection pump when or before the Maximum Allowable Injection Pressure (MAIP) specified in APPENDIX C is reached at the wellhead; and

(d) a non-resettable cumulative volume recorder attached to the injection line.

4. *Well Logging and Testing*

Well logging and testing requirements are found in APPENDIX B. The Permittee shall ensure the log and test requirements are performed within the time frames specified in APPENDIX B. Well logs and tests shall be performed according to current EPA-approved procedures. Well log and test results shall be submitted to the Director within sixty (60) days of completion of the logging or testing activity, and shall include a report describing the methods used during logging or testing and an interpretation of the test or log results.

5. *Postponement of Construction or Conversion*

The Permittee shall complete well construction within one year of the Effective Date of the Permit, or in the case of an Area Permit within one year of Authorization of the additional well. Authorization to construct and operate shall expire if the well has not been constructed within one year of the Effective Date of the Permit or Authorization and the Permit may be terminated under 40 CFR 144.40, unless the Permittee has notified the Director and requested an extension prior to expiration. Notification shall be in writing, and shall state the reasons for the delay and provide an estimated completion date. Once Authorization has expired under this part, the complete permit process including opportunity for public comment may be required before Authorization to construct and operate may be reissued.

6. *Workovers and Alterations*

Workovers and alterations shall meet all conditions of the Permit. Prior to beginning any addition or physical alteration to an injection well that may significantly affect the tubing, packer or casing, the Permittee shall give advance notice to the Director and obtain the Director's approval. The Permittee shall record all changes to well construction on a Well Rework Record (EPA Form 7520-12), and shall provide this and any other record of well workover, logging, or test data to EPA within sixty (60) days of completion of the activity.

A successful demonstration of Part I MI is required following the completion of any well workover or alteration which affects the casing, tubing, or packer. Injection operations shall not be resumed until the well has successfully demonstrated mechanical integrity and the Director has provided written approval to resume injection..

Section B. MECHANICAL INTEGRITY

The Permittee is required to ensure each injection well maintains mechanical integrity at all times. The Director, by written notice, may require the Permittee to comply with a schedule describing when mechanical integrity demonstrations shall be made.

An injection well has mechanical integrity if:

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

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

1. Demonstration of Mechanical Integrity (MI).

The operator shall demonstrate MI prior to commencing injection and periodically thereafter. Well-specific conditions dictate the methods and the frequency for demonstrating MI and are discussed in the Statement of Basis. The logs and tests are designed to demonstrate both internal (Part I) and external (Part II) MI as described above. The conditions present at this well site warrant the methods and frequency required in Appendix B of this Permit.

In addition to these regularly scheduled demonstrations of MI, the operator shall demonstrate internal (Part I) MI after any workover which affects the tubing, packer or casing.

The Director may require additional or alternative tests if the results presented by the operator are not satisfactory to the Director to demonstrate there is no movement of fluid into or between USDWs resulting from injection activity. Results of MI tests shall be submitted to the Director as soon as possible but no later than sixty (60) days after the test is complete.

2. Mechanical Integrity Test Methods and Criteria

EPA-approved methods shall be used to demonstrate mechanical integrity. Ground Water Section Guidance No. 34 "Cement Bond Logging Techniques and Interpretation", Ground Water Section Guidance No. 37, "Demonstrating Part II (External) Mechanical Integrity for a Class II injection well permit", and Ground Water Section Guidance No. 39, "Pressure Testing Injection Wells for Part I (Internal) Mechanical Integrity" are available from EPA and will be provided upon request.

The Director may stipulate specific test methods and criteria best suited for a specific well construction and injection operation.

3. Notification Prior to Testing.

The Permittee shall notify the Director at least seven calendar days prior to any mechanical integrity test unless the mechanical integrity test is conducted after a well construction, well conversion, or a well rework, in which case any prior notice is sufficient. The Director may allow a shorter notification period if it would be sufficient to enable EPA to witness the mechanical integrity test. Notification may be in the form of a yearly or quarterly schedule of planned mechanical integrity tests, or it may be on an individual basis.

4. Loss of Mechanical Integrity.

If the well fails to demonstrate mechanical integrity during a test, or a loss of mechanical integrity becomes evident during operation (such as presence of pressure in the TCA, water flowing at the surface, etc.), the Permittee shall notify the Director within 24 hours (see Part III Section E Paragraph 11(e) of this Permit) and the well shall be shut-in within 48 hours unless the Director requires immediate shut-in.

Within five days, the Permittee shall submit a follow-up written report that documents test results, repairs undertaken or a proposed remedial action plan.

Injection operations shall not be resumed until after the well has successfully been repaired and demonstrated mechanical integrity, and the Director has provided approval to resume injection.

Section C. WELL OPERATION

INJECTION BETWEEN THE OUTERMOST CASING PROTECTING UNDERGROUND SOURCES OF DRINKING WATER AND THE WELL BORE IS PROHIBITED.

Injection is approved under the following conditions:

1. Requirements Prior to Commencing Injection.

Well injection, including for new wells authorized by an Area Permit under 40 CFR 144.33 (c), may commence only after all well construction and pre-injection requirements herein have been met and approved. The Permittee may not commence injection until construction is complete, and

(a) The Permittee has submitted to the Director a notice of completion of construction and a completed EPA Form 7520-10 or 7520-12; all applicable logging and testing requirements of this Permit (see APPENDIX B) have been fulfilled and the records submitted to the Director; mechanical integrity pursuant to 40 CFR 146.8 and Part II Section B of this Permit has been demonstrated; and

(i) The Director has inspected or otherwise reviewed the new injection well and finds it is in compliance with the conditions of the Permit; or

(ii) The Permittee has not received notice from the Director of his or her intent to inspect or otherwise review the new injection well within 13 days of the date of the notice in Paragraph 1a, in which case prior inspection or review is waived and the Permittee may commence injection.

2. Injection Interval.

Injection is permitted only within the approved injection interval, listed in APPENDIX C. Additional individual injection perforations may be added provided that they remain within the approved injection interval and the Permittee provides notice to the Director in accordance with Part II, Section A, Paragraph 6.

3. Injection Pressure Limitation

(a) The permitted Maximum Allowable Injection Pressure (MAIP), measured at the wellhead, is found in APPENDIX C. Injection pressure shall not exceed the amount the Director determines is appropriate to ensure that injection does not initiate new fractures or propagate existing fractures in the confining zone adjacent to USDWs. In no case shall injection pressure cause the movement of injection or formation fluids into a USDW.

(b) The Permittee may request a change of the MAIP, or the MAIP may be increased or decreased by the Director in order to ensure that the requirements in Paragraph (a) above are fulfilled. The Permitee may be required to conduct a step rate injection test or other suitable test to provide information for determining the fracture pressure of the injection zone. Change of the permitted MAIP by the Director shall be by modification of this Permit and APPENDIX C.

4. *Injection Volume Limitation.*

Injection volume is limited to the total volume specified in APPENDIX C.

5. *Injection Fluid Limitation.*

Injected fluids are limited to those identified in 40 CFR 144.6(b)(2) as fluids used for enhanced recovery of oil or natural gas, including those which are brought to the surface in connection with conventional oil or natural gas production that may be commingled with waste waters from gas plants which are an integral part of production operations unless those waters are classified as a hazardous waste at the time of injection, pursuant to 40 CFR 144.6(b). Non-exempt wastes, including unused fracturing fluids or acids, gas plant cooling tower cleaning wastes, service wastes and vacuum truck wastes, are NOT approved for injection. This well is NOT approved for commercial brine injection, industrial waste fluid disposal or injection of hazardous waste as defined by CFR 40 Part 261. The Permittee shall provide a listing of the sources of injected fluids in accordance with the reporting requirements in Part II Section D Paragraph 4 and APPENDIX D of this Permit.

6. *Tubing-Casing Annulus (TCA)*

The tubing-casing annulus (TCA) shall be filled with water treated with a corrosion inhibitor, or other fluid approved by the Director. The TCA valve shall remain closed during normal operating conditions and the TCA pressure shall be maintained at zero (0) psi.

If TCA pressure cannot be maintained at zero (0) psi, the Permittee shall follow the procedures in Ground Water Section Guidance No. 35 "Procedures to follow when excessive annular pressure is observed on a well."

Section D. MONITORING, RECORDKEEPING, AND REPORTING OF RESULTS

1. *Monitoring Parameters, Frequency, Records and Reports.*

Monitoring parameters are specified in APPENDIX D. Pressure monitoring recordings shall be taken at the wellhead. The listed parameters are to be monitored, recorded and reported at the frequency indicated in APPENDIX D even during periods when the well is not operating.

Monitoring records must include:

(a) the date, time, exact place and the results of the observation, sampling, measurement, or analysis, and;

(b) the name of the individual(s) who performed the observation, sampling, measurement, or analysis, and;

(c) the analytical techniques or methods used for analysis.

2. *Monitoring Methods.*

(a) Monitoring observations, measurements, samples, etc. taken for the purpose of complying with these requirements shall be representative of the activity or condition being monitored.

(b) Methods used to monitor the nature of the injected fluids must comply with analytical methods cited and described in Table 1 of 40 CFR 136.3 or Appendix III of 40 CFR 261, or by other methods that have been approved in writing by the Director.

(c) Injection pressure, annulus pressure, injection rate, and cumulative injected volumes shall be observed and recorded at the wellhead under normal operating conditions, and all parameters shall be observed simultaneously to provide a clear depiction of well operation.

(d) Pressures are to be measured in pounds per square inch (psi).

(e) Fluid volumes are to be measured in standard oil field barrels (bbl).

(f) Fluid rates are to be measured in barrels per day (bbl/day).

3. Records Retention.

(a) Records of calibration and maintenance, and all original strip chart recordings for continuous monitoring instrumentation, copies of all reports required by this permit, and records of all data used to complete the application for this permit shall be retained for a period of AT LEAST THREE (3) YEARS from the date of the sample, measurement, report, or application. This period may be extended anytime prior to its expiration by request of the Director.

(b) Records of the nature and composition of all injected fluids must be retained until three (3) years after the completion of any plugging and abandonment (P&A) procedures specified under 40 CFR 144.52(a)(6) or under Part 146 Subpart G, as appropriate. The Director may require the Permittee to deliver the records to the Director at the conclusion of the retention period. The Permittee shall continue to retain the records after the three (3) year retention period unless the Permittee delivers the records to the Director or obtains written approval from the Director to discard the records.

4. Annual Reports.

Whether the well is operating or not, the Permittee shall submit an Annual Report to the Director that summarizes the results of the monitoring required by Part II Section D and APPENDIX D.

The first Annual Report shall cover the period from the effective date of the Permit through December 31 of that year. Subsequent Annual Reports shall cover the period from January 1 through December 31 of the reporting year. Annual Reports shall be submitted by February 15 of the year following data collection. EPA Form 7520-11 may be copied and shall be used to submit the Annual Report, however, the monitoring requirements specified in this Permit are mandatory even if EPA Form 7520-11 indicates otherwise.

Section E. PLUGGING AND ABANDONMENT

1. Notification of Well Abandonment, Conversion or Closure.

The Permittee shall notify the Director in writing at least forty-five (45) days prior to: 1) plugging and abandoning an injection well, 2) converting to a non-injection well, and 3) in the case of an Area Permit, before closure of the project.

2. Well Plugging Requirements

Prior to abandonment, the injection well shall be plugged with cement in a manner which isolates the injection zone and prevents the movement of fluids into or between underground sources of drinking water, and in accordance with 40 CFR 146.10 and other applicable Federal, State or local law or regulations. Tubing, packer and other downhole apparatus shall be removed. Cement with additives such as accelerators and retarders that control or enhance cement properties may be used for plugs; however, volume-extending additives and gel cements are not approved for plug use. Plug placement shall be verified by tagging. Plugging gel of at least 9.2 lb/gal shall be placed between all plugs. A minimum 50 ft surface plug shall be set inside and outside of the surface casing to seal pathways for fluid migration into the subsurface. The Plugging Record must be certified as accurate and complete by the person responsible for the plugging operation. Prior to placement of the cement plug(s) the well shall be in a state of static equilibrium with the mud weight equalized top to bottom, either by circulating the mud in the well at least once or by a comparable method prescribed by the Director.

3. Approved Plugging and Abandonment Plan.

The approved plugging and abandonment plan is incorporated into this Permit as APPENDIX E. Changes to the approved plugging and abandonment plan must be approved by the Director prior to beginning plugging operations. The Director also may require revision of the approved plugging and abandonment plan at any time prior to plugging the well.

4. Forty Five (45) Day Notice of Plugging and Abandonment.

The Permittee shall notify the Director at least forty-five (45) days prior to plugging and abandoning a well and provide notice of any anticipated change to the approved plugging and abanonment plan.

5. Plugging and Abandonment Report.

Within sixty (60) days after plugging a well, the Permittee shall submit a report (EPA Form 7520-13) to the Director. The plugging report shall be certified as accurate by the person who performed the plugging operation. Such report shall consist of either:

(a) A statement that the well was plugged in accordance with the approved plugging and abandonment plan; or

(b) Where actual plugging differed from the approved plugging and abandonment plan, an updated version of the plan, on the form supplied by the Director, specifying the differences.

6. Inactive Wells.

After any period of two years during which there is no injection the Permittee shall plug and abandon the well in accordance with Part II Section E Paragraph 2 of this Permit unless the Permittee:

(a) Provides written notice to the Director;

(b) Describes the actions or procedures the Permittee will take to ensure that the well will not endanger USDWs during the period of inactivity. These actions and procedures shall include compliance with mechanical integrity demonstration, Financial Responsibility and all other permit requirements designed to protect USDWs; and

(c) Receives written notice by the Director temporarily waiving plugging and abandonment requirements.

PART III. CONDITIONS APPLICABLE TO ALL PERMITS

Section A. EFFECT OF PERMIT

The Permittee is allowed to engage in underground injection in accordance with the conditions of this Permit. The Permittee shall not construct, operate, maintain, convert, plug, abandon, or conduct any other activity in a manner that allows the movement of fluid containing any contaminant into underground sources of drinking water, if the presence of that contaminant may cause a violation of any primary drinking water regulation under 40 CFR 142 or may otherwise adversely affect the health of persons. Any underground injection activity not authorized by this Permit or by rule is prohibited. Issuance of this Permit does not convey property rights of any sort or any exclusive privilege; nor does it authorize any injury to persons or property, any invasion of other private rights, or any infringement of any other Federal, State or local law or regulations. Compliance with the terms of this Permit does not constitute a defense to any enforcement action brought under the provisions of Section 1431 of the Safe Drinking Water Act (SDWA) or any other law governing protection of public health or the environment, for any imminent and substantial endangerment to human health or the environment, nor does it serve as a shield to the Permittee's independent obligation to comply with all UIC regulations. Nothing in this Permit relieves the Permittee of any duties under applicable regulations.

Section B. CHANGES TO PERMIT CONDITIONS

1. Modification, Reissuance, or Termination.

The Director may, for cause or upon a request from the Permittee, modify, revoke and reissue, or terminate this Permit in accordance with 40 CFR 124.5, 144.12, 144.39, and 144.40. Also, this Permit is subject to minor modification for causes as specified in 40 CFR 144.41. The filing of a request for modification, revocation and reissuance, termination, or the notification of planned changes or anticipated noncompliance on the part of the Permittee does not stay the applicability or enforceability of any condition of this Permit.

2. Conversions.

The Director may, for cause or upon a written request from the Permittee, allow conversion of the well from a Class II injection well to a non-Class II well. Conversion may not proceed until the Permittee receives written approval from the Director. Conditions of such conversion may include but are not limited to, approval of the proposed well rework, follow up demonstration of mechanical integrity, well-specific monitoring and reporting following the conversion, and demonstration of practical use of the converted configuration.

3. Transfer of Permit.

Under 40 CFR 144.38, this Permit is transferable provided the current Permittee notifies the Director at least thirty (30) days in advance of the proposed transfer date (EPA Form 7520-7) and provides a written agreement between the existing and new Permittees containing a specific date for transfer of Permit responsibility, coverage and liability between them. The notice shall adequately demonstrate that the financial responsibility requirements of 40 CFR 144.52(a)(7) will be met by the new Permittee. The Director may require modification or revocation and reissuance of the Permit to change the name of the Permittee and incorporate such other requirements as may be necessary under the Safe Drinking Water Act; in some cases, modification or revocation and reissuance is mandatory.

4. Permittee Change of Address.

Upon the Permittee's change of address, or whenever the operator changes the address where monitoring records are kept, the Permittee must provide written notice to the Director within 30 days.

5. Construction Changes, Workovers, Logging and Testing Data

The Permittee shall give advance notice to the Director, and shall obtain the Director's written approval prior to any physical alterations or additions to the permitted facility. Alterations or workovers shall meet all conditions as set forth in this permit. The Permittee shall record any changes to the well construction on a Well Rework Record (EPA Form 7520-12), and shall provide this and any other record of well workovers, logging , or test data to EPA within sixty (60) days of completion of the activity.

Following the completion of any well workovers or alterations which affect the casing, tubing, or packer, a successful demonstration of mechanical integrity (Part III, Section F of this Permit) shall be made, and written authorization from the Director received, prior to resuming injection activities.

Section C. SEVERABILITY

The Provisions of this Permit are severable, and if any provision of this Permit or the application of any provision of this Permit to any circumstance, is held invalid, the application of such provision to other circumstances, and the remainder of this Permit shall not be affected thereby.

Section D. CONFIDENTIALITY

In accordance with 40 CFR Part 2 and 40 CFR 144.5, information submitted to EPA pursuant to this Permit may be claimed as confidential by the submitter. Any such claim must be asserted at the time of submission by stamping the words "confidential business information" on each page containing such information. If no claim is made at the time of submission, EPA may make the information available to the public without further notice. If a claim is asserted, the validity of the claim will be assessed in accordance with the procedures in 40 CFR Part 2 (Public Information). Claims of confidentiality for the following information will be denied:

- The name and address of the Permittee, and
- information which deals with the existence, absence or level of contaminants in drinking water.

Section E. GENERAL PERMIT REQUIREMENTS

1. Duty to Comply.

The Permittee must comply with all conditions of this Permit. Any noncompliance constitutes a violation of the Safe Drinking Water Act (SDWA) and is grounds for enforcement action; for Permit termination, revocation and reissuance, or modification; or for denial of a permit renewal application; except that the Permittee need not comply with the provisions of this Permit to the extent and for the duration such noncompliance is authorized in an emergency permit under 40 CFR 144.34. All violations of the SDWA may subject the Permittee to penalties and/or criminal prosecution as specified in Section 1423 of the SDWA.

2. Duty to Reapply.

If the Permittee wishes to continue an activity regulated by this Permit after the expiration date of this Permit, under 40 CFR 144.37 the Permittee must apply for a new permit prior to the expiration date.

3. Need to Halt or Reduce Activity Not a Defense.

It shall not be a defense for a Permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this Permit.

4. Duty to Mitigate.

The Permittee shall take all reasonable steps to minimize or correct any adverse impact on the environment resulting from noncompliance with this Permit.

5. Proper Operation and Maintenance.

The Permittee shall at all times properly operate and maintain all facilities and systems of treatment and control (and related appurtenances) which are installed or used by the Permittee to achieve compliance with the conditions of this Permit. Proper operation and maintenance includes effective performance, adequate funding, adequate operator staffing and training, and adequate laboratory and process controls, including appropriate quality assurance procedures. This provision requires the operation of back-up or auxiliary facilities or similar systems only when necessary to achieve compliance with the conditions of this Permit.

6. Permit Actions.

This Permit may be modified, revoked and reissued or terminated for cause. The filing of a request by the Permittee for a permit modification, revocation and reissuance, or termination, or a notification of planned changes or anticipated noncompliance, does not stay any permit condition.

7. Property Rights.

This Permit does not convey any property rights of any sort, or any exclusive privilege.

8. Duty to Provide Information.

The Permittee shall furnish to the Director, within a time specified, any information which the Director may request to determine whether cause exists for modifying, revoking and reissuing, or terminating this permit, or to determine compliance with this permit. The Permittee shall also furnish to the Director, upon request, copies of records required to be kept by this Permit. The Permittee is required to submit any information required by this Permit or by the Director to the mailing address designated in writing by the Director.

9. Inspection and Entry.

The Permittee shall allow the Director, or an authorized representative, upon the presentation of credentials and other documents as may be required by law, to:

(a) Enter upon the Permittee's premises where a regulated facility or activity is located or conducted, or where records must be kept under the conditions of this Permit;

(b) Have access to and copy, at reasonable times, any records that must be kept under the conditions of this Permit;

(c) Inspect at reasonable times any facilities, equipment (including monitoring and control equipment), practices, or operations regulated or required under this Permit; and,

(d) Sample or monitor at reasonable times, for the purpose of assuring permit compliance or as otherwise authorized by the SDWA, any substances or parameters at any location.

10. Signatory Requirements.

All applications, reports or other information submitted to the Director shall be signed and certified according to 40 CFR 144.32. This section explains the requirements for persons duly authorized to sign documents, and provides wording for required certification.

11. Reporting Requirements.

(a) Planned changes. The Permittee shall give notice to the Director as soon as possible of any planned changes, physical alterations or additions to the permitted facility, and prior to commencing such changes.

(b) Anticipated noncompliance. The Permittee shall give advance notice to the Director of any planned changes in the permitted facility or activity which may result in noncompliance with permit requirements.

(c) Monitoring Reports. Monitoring results shall be reported at the intervals specified in this Permit.

(d) Compliance schedules. Reports of compliance or noncompliance with, or any progress reports on, interim and final requirements contained in any compliance schedule of this Permit shall be submitted no later than 30 days following each schedule date.

(e) Twenty-four hour reporting. The Permittee shall report to the Director any noncompliance which may endanger human health or the environment, including:

(i) Any monitoring or other information which indicates that any contaminant may cause endangerment to a USDW; or

(ii) Any noncompliance with a permit condition or malfunction of the injection system which may cause fluid migration into or between USDWs.

Information shall be provided, either directly or by leaving a message, within twenty-four (24) hours from the time the permittee becomes aware of the circumstances by telephoning (800) 227-8917 and requesting EPA Region VIII UIC Program Compliance and Technical Enforcement Director, or by contacting the EPA Region VIII Emergency Operations Center at (303) 293-1788.

In addition, a follow up written report shall be provided to the Director within five (5) days of the time the Permittee becomes aware of the circumstances. The written submission shall contain a description of the noncompliance and its cause, the period of noncompliance including exact dates and times, and if the noncompliance has not been corrected the anticipated time it is expected to continue; and the steps taken or planned to reduce, eliminate, and prevent recurrence of the noncompliance.

(f) Oil Spill and Chemical Release Reporting: The Permittee shall comply with all reporting requirements related to the occurence of oil spills and chemical releases by contacting the National Response Center (NRC) at (800) 424-8802, (202) 267-2675, or through the NRC website http://www.nrc.uscg.mil/index.htm.

(g) Other Noncompliance. The Permittee shall report all instances of noncompliance not reported under paragraphs Part III, Section E Paragraph 11(b) or Section E, Paragraph 11(e) at the time the monitoring reports are submitted. The reports shall contain the information listed in Paragraph 11(e) of this Section.

(h) Other information. Where the Permittee becomes aware that it failed to submit any relevant facts in the permit application, or submitted incorrect information in a permit application or in any report to the Director, the Permittee shall promptly submit such facts or information to the Director.

Section F. FINANCIAL RESPONSIBILITY

1. Method of Providing Financial Responsibility.

The Permittee shall maintain continuous compliance with the requirement to maintain financial responsibility and resources to close, plug, and abandon the underground injection well(s). No substitution of a demonstration of financial responsibility shall become effective until the Permittee receives written notification from the Director that the alternative demonstration of financial responsibility is acceptable. The Director may, on a periodic basis, require the holder of a permit to revise the estimate of the resources needed to plug and abandon the well to reflect changes in such costs and may require the Permittee to provide a revised demonstration of financial responsibility.

2. Insolvency.

In the event of:

(a) the bankruptcy of the trustee or issuing institution of the financial mechanism; or

(b) suspension or revocation of the authority of the trustee institution to act as trustee; or

(c) the institution issuing the financial mechanism losing its authority to issue such an instrument

the Permittee must notify the Director in writing, within ten (10) business days, and the Permittee must establish other financial assurance or liability coverage acceptable to the Director within sixty (60) days after any event specified in (a), (b), or (c) above.

The Permittee must also notify the Director by certified mail of the commencement of voluntary or involuntary proceedings under Title 11 (Bankruptcy), U.S. Code naming the owner or operator as debtor, within ten (10) business days after the commencement of the proceeding. A guarantor, if named as debtor of a corporate guarantee, must make such a notification as required under the terms of the guarantee.

APPENDIX A

WELL CONSTRUCTION REQUIREMENTS

See diagram.

The Blackjack Federal No. 10-5-9-17 was drilled to total depth of 6,015 feet (KB) in the Basal Carbonate Member of the Green River Formation.

Surface casing (8-5/8 inch) was set at a depth of 333 feet in a 12-1/4 inch hole using 160 sacks of Class "G" cement which was circulated to the surface.

Production casing (5-1/2 inch) was set at a depth of 5,985 feet (KB) in a 7-7/8 inch hole with 350 sacks of Premium Lite II and 400 sacks of 50/50 Pozmix. Well construction is considered adequate to protect all USDWs.

The EPA calculates top of cement (TOC) at 1,154 feet from the surface.

The Schematic Diagram shows the proposed-current injection perforations in the Garden Gulch and Douglas Creek Members of the Green River Formation. Additional perforations may be added at a later time between the depths of 3,976 feet and the top of the Wasatch Formation (Estimated to be 6,062 feet) provided that the operator first notifies the Director and later submits an updated Well Rework Record (EPA Form 7520-12) and schematic diagram.

The packer will be set no higher than 100 feet above the top perforation.

Blackjack Federal 10-5-9-17

Spud Date: 12/1/04
Put on Production: 1/11/05
GL: 5251' KB: 5263'

Proposed Injection
Wellbore Diagram

Initial Production: BOPD,
MCFD, BWPD

SURFACE CASING

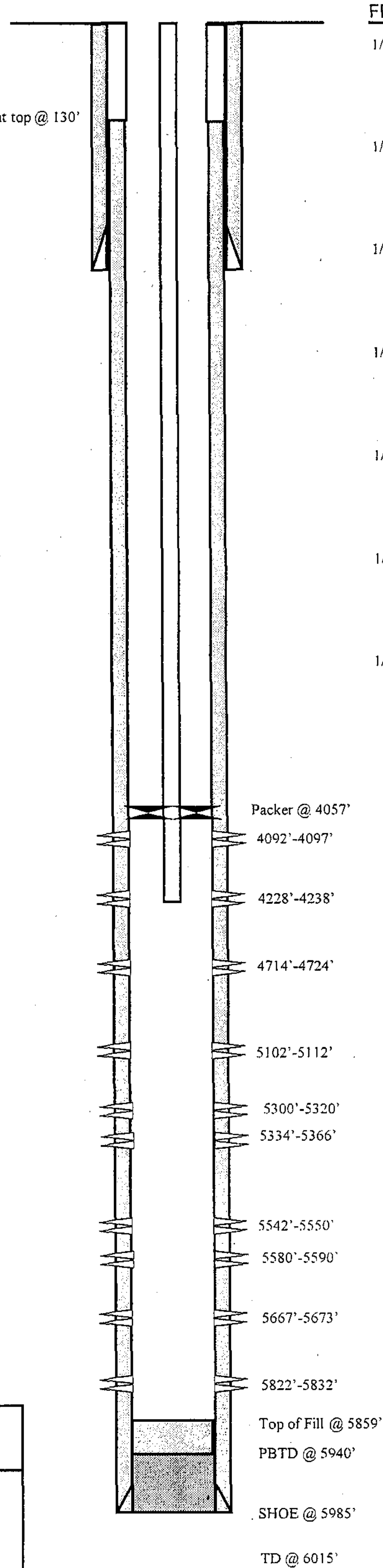
CSG SIZE: 8-5/8"
GRADE: J-55
WEIGHT: 24#
LENGTH: 8 jts (323.05')
DEPTH LANDED: 333.05'
HOLE SIZE:12-1/4"
CEMENT DATA: 160 sxs Class G cement. Est 4 bbls cmt to surface.

PRODUCTION CASING

CSG SIZE: 5-1/2"
GRADE: J-55
WEIGHT: 15.5#
LENGTH: 142 jts. (5988.91')
DEPTH LANDED: 5985.35' KB
HOLE SIZE: 7-7/8"
CEMENT DATA: 350 sxs Premlite II & 400 sxs 50/50 POZ.
CEMENT TOP AT: 130'

TUBING

SIZE/GRADE/WT.: 2-7/8" / J-55 / 6.5#
NO. OF JOINTS: 169 jts (5641.19')
TUBING ANCHOR: 5653.19' KB
NO. OF JOINTS: 1 jt (33.39')
SEATING NIPPLE: 2-7/8" (1.10')
SN LANDED AT: 5689.38' KB
NO. OF JOINTS: 2 jts (66.70')
TOTAL STRING LENGTH: EOT @ 5757.63' w/ 12' KB



FRAC JOB

1/04/05	5822'-5832'	**Frac CP5 sands as follows:** 18,712# 20/40 sand in 268 bbls Lightning 17 frac fluid. Treated @ avg press of 2130 psi w/avg rate of 24.5 BPM. ISIP 2145 psi. Calc. flush: 5820 gal. Actual flush: 5859 gal.
1/04/05	5542'-5673'	**Frac CP3, 1 & .5 sands as follows:** 64,105# 20/40 sand in 524 bbls Lightning 17 frac fluid. Treated @ avg press of 1956 psi w/avg rate of 24.5 BPM. ISIP 1990 psi. Calc. flush: 5540 gal. Actual flush: 5573 gal.
1/04/05	5300'-5366'	**Frac LODC sands as follows:** 199,147# 20/40 sand in 1337 bbls Lightning 17 frac fluid. Treated @ avg press of 1684 psi w/avg rate of 24.5 BPM. ISIP 2100 psi. Calc. flush: 5298 gal. Actual flush: 5330 gal.
1/04/05	5102'-5112'	**Frac A3 sands as follows:** 44,330# 20/40 sand in 411 bbls Lightning 17 frac fluid. Treated @ avg press of 1968 psi w/avg rate of 24.5 BPM. ISIP 2300 psi. Calc. flush: 5100 gal. Actual flush: 5124 gal.
1/05/05	4714'-4724'	**Frac D2 sands as follows:** 19,177# 20/40 sand in 241 bbls Lightning 17 frac fluid. Treated @ avg press of 1791 psi w/avg rate of 24.3 BPM. ISIP 1850 psi. Calc. flush: 4712 gal. Actual flush: 4725 gal.
1/05/05	4228'-4238'	**Frac GB6 sands as follows:** 63,938# 20/40 sand in 493 bbls Lightning 17 frac fluid. Treated @ avg press of 2267 psi w/avg rate of 24.5 BPM. ISIP 1780 psi. Calc. flush: 4226 gal. Actual flush: 4259 gal.
1/05/05	4092'-4097'	**Frac GB2 sands as follows:** 14,210# 20/40 sand in 230 bbls Lightning 17 frac fluid. Treated @ avg press of 2447 psi w/avg rate of 24.6 BPM. ISIP 1970 psi. Calc. flush: 4090 gal. Actual flush: 4003 gal.

PERFORATION RECORD

12/30/04	5822'-5832'	4 JSPF	40 holes
01/04/05	5667'-5673'	4 JSPF	24 holes
01/04/05	5580'-5590'	4 JSPF	40 holes
01/04/05	5542'-5550'	4 JSPF	32 holes
01/04/05	5334'-5366'	2 JSPF	64 holes
01/04/05	5300'-5320'	2 JSPF	40 holes
01/04/05	5102'-5112'	4 JSPF	40 holes
01/04/05	4714'-4724'	4 JSPF	40 holes
01/05/05	4228'-4238'	4 JSPF	40 holes
01/05/05	4092'-4097'	4 JSPF	20 holes

NEWFIELD

Blackjack Federal #10-5-9-17
1676' FSL & 1982' FEL
NWSE Section 5-T9S-R17E
Duchesne Co, Utah
API #43-013-32553; Lease #UTU-74808

MC 4/18/05

APPENDIX B

LOGGING AND TESTING REQUIREMENTS

Logs.
Logs will be conducted according to current UIC guidance. It is the responsibility of the Permittee to obtain and use guidance prior to conducting any well logging required as a condition of this permit.

NO LOGGING REQUIREMENTS

Tests.
Tests will be conducted according to current UIC guidance. It is the responsibility of the Permittee to obtain and use guidance prior to conducting any well test required as a condition of this permit.

WELL NAME: Blackjack Federal 10-5-9-17

TYPE OF TEST	DATE DUE
Pore Pressure	Prior to receiving authorization to inject.
Standard Annulus Pressure	Prior to receiving authorization to inject and at least once within any five year period following the last successful test.

APPENDIX C

OPERATING REQUIREMENTS

MAXIMUM ALLOWABLE INJECTION PRESSURE:

Maximum Allowable Injection Pressure (MAIP) as measured at the surface shall not exceed the pressure(s) listed below.

WELL NAME	MAXIMUM ALLOWED INJECTION PRESSURE (psi) ZONE 1 (Upper)
Blackjack Federal 10-5-9-17	1,430

INJECTION INTERVAL(S):

Injection is permitted only within the approved injection interval listed below. Injection perforations may be altered provided they remain within the approved injection interval and the Permittee provides notice to the Director in accordance with Part II, Section A, Paragraph 6. Specific injection perforations can be found in Appendix A.

WELL NAME: Blackjack Federal 10-5-9-17

FORMATION NAME	APPROVED INJECTION INTERVAL (KB, ft) TOP	BOTTOM	FRACTURE GRADIENT (psi/ft)
Green River Formation: Garden Gulch & Douglas Creek Members	3,976.00 -	6,062.00	0.790

ANNULUS PRESSURE:

The annulus pressure shall be maintained at zero (0) psi as measured at the wellhead. If this pressure cannot be maintained, the Permittee shall follow the procedures listed under Part II, Section C. 6. of this permit.

MAXIMUM INJECTION VOLUME:

There is no limitation on the number of barrels per day (bbls/day) of water that shall be injected into this well, provided further that in no case shall injection pressure exceed that limit shown in Appendix C.

APPENDIX D

MONITORING AND REPORTING PARAMETERS

This is a listing of the parameters required to be observed, recorded, and reported. Refer to the permit Part II, Section D, for detailed requirements for observing, recording, and reporting these parameters.

OBSERVE MONTHLY AND RECORD AT LEAST ONCE EVERY THIRTY DAYS	
OBSERVE AND RECORD	Injection pressure (psig)
	Annulus pressure(s) (psig)
	Injection rate (bbl/day)
	Fluid volume injected since the well began injecting (bbls)

ANNUALLY	
ANALYZE	Injected fluid total dissolved solids (mg/l)
	Injected fluid specific gravity
	Injected fluid specific conductivity
	Injected fluid pH

ANNUALLY	
REPORT	Each month's maximum and averaged injection pressures (psig)
	Each month's maximum and minimum annulus pressure(s) (psig)
	Each month's injected volume (bbl)
	Fluid volume injected since the well began injecting (bbl)
	Written results of annual injected fluid analysis
	Sources of all fluids injected during the year

In addition to these items, additional Logging and Testing results may be required periodically. For a list of those items and their due dates, please refer to APPENDIX B - LOGGING AND TESTING REQUIREMENTS.

APPENDIX E

PLUGGING AND ABANDONMENT REQUIREMENTS

Plugging and Abandonment: The well shall be plugged in a manner that isolates the injection zone and prevents movement of fluids into or between Underground Sources of Drinking Water (USDW). Tubing, packers, and any downhole apparatus shall be removed. Class A, C, G, and H cements, with additives such as accelerators and retarders that control or enhance cement properties, may be used for plugs; however, volume extending additives and gel cements are not approved for plug use. Plug placement shall be verified by tagging. Plugging gel of at least 9.2 lb/gal shall be placed between all plugs. A minimum 50 ft. surface plug shall be set inside and outside of the surface casing to seal pathways for fluid migration into the subsurface. Within sixty (60) days after plugging the owner or operator shall submit Plugging Record (EPA Form 7520-13) to the Director. The Plugging Record must be certified as accurate and complete by the person responsible for the plugging operation. At a minimum, the following plugs are required:

(1)□Isolate the injection zone: Remove down hole apparatus and perform clean out; displace well fluid with plugging gel. Set a cast iron bridge plug (CIBP) within the innermost casing no more than 50 ft. above the top perforation with a minimum of 20 ft. cement plug on top of the CIBP.

(2)□Isolate the Trona-Bird's Nest and Mahogany Oil Shale: Perforate and squeeze cement up the backside of the outermost casing from at least 55 ft. above the top of the Trona-Bird's Nest to at least 55 ft. below the base of Mahogany Oil Shale, unless there is existing cement across this interval.

(3)□Isolate the Uinta Formation from the Green River Formation: Perforate and squeeze a minimum of 110 ft. cement up the backside of the outermost casing to isolate the contact between the Uinta Formation and the Green River Formation, unless there is existing cement across this interval. Set a minimum 110 ft. cement plug in the innermost casing centered on the contact between the Green River and Uinta Formations.

(4)□Isolate Surface Fluid Migration Paths:
a.□If the depth of the lowermost USDW is above the base of surface casing, perforate the outermost casing string 50 ft. below the base of surface casing and circulate cement to the surface, unless there is existing cement across this interval; OR

b.□If the depth of the lowermost USDW is below the base of surface casing, perforate the outermost casing string 50 ft. below the base of the lowermost USDW and circulate cement to surface; AND

c.□Set a cement plug inside the innermost casing string from 50 ft. below the base of the surface casing to surface.

APPENDIX F

CORRECTIVE ACTION REQUIREMENTS

No corrective action is deemed necessary for this project.

STATEMENT OF BASIS

NEWFIELD PRODUCTION CO.
BLACKJACK FEDERAL 10-5-9-17
DUCHESNE COUNTY, UT

EPA PERMIT NO. UT22228-09492

CONTACT: Emmett Schmitz
U. S. Environmental Protection Agency Region 8
Mailcode: 8P-W-UIC
1595 Wynkoop Street
Denver, Colorado 80202-1129
Telephone: 1-800-227-8917 ext. 312-6174

This STATEMENT OF BASIS gives the derivation of site-specific UIC Permit conditions and reasons for them. Referenced sections and conditions correspond to sections and conditions in the Permit.

EPA UIC permits regulate the injection of fluids into underground injection wells so that the injection does not endanger underground sources of drinking water. EPA UIC permit conditions are based upon the authorities set forth in regulatory provisions at 40 CFR Parts 144 and 146, and address potential impacts to underground sources of drinking water. Under 40 CFR 144.35 Issuance of this permit does not convey any property rights of any sort or any exclusive privilege, nor authorize injury to persons or property of invasion of other private rights, or any infringement of other Federal, State or local laws or regulations. Under 40 CFR 144 Subpart D, certain conditions apply to all UIC Permits and may be incorporated either expressly or by reference. General Permit conditions for which the content is mandatory and not subject to site-specific differences (40 CFR Parts 144, 146 and 147) are not discussed in this document.

Upon the Effective Date when issued, the Permit authorizes the construction and operation of injection wells so that the injection does not endanger underground sources of drinking water, governed by the conditions specified in the Permit. The Permit is issued for the operating life of the injection well or project unless terminated for reasonable cause under 40 CFR 144.39, 144.40 and 144.41. The Permit is subject to EPA review at least once every five (5) years to determine if action is required under 40 CFR 144.36(a).

PART I. General Information and Description of Facility

Newfield Production Co.
1001 Seventeenth Street, Suite 2000
Denver, CO 80202

on

December 23, 2011

submitted an application for an Underground Injection Control (UIC) Program Permit or Permit Modification for the following injection well or wells:

Blackjack Federal 10-5-9-17
1676' FSL & 1982' FEL, NWSE S5, T9S, R17E
Duchesne County, UT

Regulations specific to Uintah-Ouray Indian Reservation injection wells are found at 40 CFR 147 Subpart TT.

The application, including the required information and data necessary to issue or modify a UIC Permit in accordance with 40 CFR Parts 144, 146 and 147, was reviewed and determined by EPA to be complete.

The Permit will expire upon delegation of primary enforcement responsibility (primacy) for applicable portions of the UIC Program to the Ute Indian Tribe or the State of Utah unless the delegated agency has the authority and chooses to adopt and enforce this Permit as a Tribal or State Permit.

TABLE 1.1 shows the status of the well or wells as "New", "Existing", or "Conversion" and for Existing shows the original date of injection operation. Well authorization "by rule" under 40 CFR Part 144 Subpart C expires automatically on the Effective Date of an issued UIC Permit.

The Blackjack Federal No. 10-5-9-17 is currently an active Garden Gulch-Douglas Creek Members of the Green River Formation oil well. The applicant intends to convert this oil well to an enhanced recovery injection facility.

PART II. Permit Considerations (40 CFR 146.24)

Hydrogeologic Setting

Water wells for domestic supply in this area, when present, generally are completed into the shallow alluvium, the Duchesne River Formation, or the underlying Uinta Formation, and the water generally contains approximately 500 to 1,500 mg/l and higher total dissolved solids.

The Uinta-Animas aquifer in the Uinta Basin is present in water-yielding beds of sandstone, conglomerate, and siltstone of the Duchesne River and Uinta Formations, the Renegade Tongue of the Wasatch Formation, and the Douglas Creek Member of the Green River Formation. The Renegade Tongue of the Wasatch Formation and the Douglas Creek Member of the Green River Formation contain an aquifer along the southern and eastern margins of the basin where the rocks primarily consist of fluvial, massive, irregularly bedded sandstone and siltstone. Water-yielding units in the Uinta-Animas aquifer in the Uinta Basin commonly are separated from each other and from the underlying Mesaverde aquifer by units of low permeability composed of claystone, shale, marlstone, or limestone. In the Uinta Basin, for example, the part of the aquifer in the Duchesne River and Uinta Formations ranges in thickness from 0 feet at the southern margin of the aquifer to as much as 9,000 feet in the north-central part of the aquifer. Ground-water recharge to the Uinta-Animas aquifer generally occurs in the areas of higher altitude along the margins of the basin. Ground water is discharged mainly to streams, springs, and by transpiration from vegetation growing along stream valleys. The rate of ground-water withdrawal is small, and natural discharge is approximately equal to recharge. Recharge occurs near the southern margin of the aquifer, and discharge occurs near the White and Green Rivers (from USGS publication HA 730-C). Water samples from Mesaverde sands in the nearby Natural Buttes Unit yielded highly saline water.

Geologic Setting (TABLE 2.1)

The proposed Class II enhanced oil recovery injection well is located in the Greater Monument Butte Field, T7-9S and R15-19E, which lies near the center of the broad, gently northward dipping south flank of the Uinta Basin. More than 450 million barrels of oil (63 MT) have been produced from sediments of the Uinta Basin. The Uinta Basin is a topographic and structural trough encompassing an area of more than 9,300 square miles (14,900 km) in northeast Utah. The basin is sharply asymmetrical, with a steep north flank bounded by the east-west-trending Uinta Mountains, and a gently dipping south flank. The Uinta Basin was formed in Paleocene to Eocene time, creating a large area of internal drainage which was filled by the ancestral Lake Uinta. The lacustrine, or fresh water lake-formed, sediments deposited in and around Lake Uinta make up the Uintah and Green River Formations. The southern shore of Lake Uinta was very broad and flat, resulting in large cyclic shifts of the location of the shoreline during the many repeated transgressive and regressive cycles caused by the climatic and tectonic-induced rise and fall of water levels of the lake. Distributary-mouth bars, distributary channels, and near-shore bars are the primary oil producing sandstone reservoirs in the area. (Ref: "Reservoir Characterization of the Lower Green River Formation, Southwest Uinta Basin, Utah Biannual Technical Progress Report, 4/1/99-9/30/99", by C. D. Morgan, Program Manager, November 1999, Contract DE-AC26-98BC15103).

The Duchesne River Formation is absent in this area. Shale and siltstone of the Uintah Formation outcrop and compose the surface rock throughout the area. The lower 600 feet to 800 feet of the Uinta Formation, consisting generally of shale interbedded with occasionally water-bearing sandstone lenses between 5 feet to 20 feet thick, is underlain by the Green River Formation. The Green River Formation is further subdivided into several Member and local marker units. The cyclic nature of Green River deposition in the southern shore area resulted in numerous stacked, intertonguing deltaic and near-shore sand and silt deposits. Red alluvial shale and siltstone deposits that intertongue with the Green River sediments are of the Colton and Wasatch Formations. Under the Wasatch Formation is the Mesaverde Formation, which consists primarily of continental-origin deposits of interbedded shale, sandstone, and coal.

The geologic dip is about 200 feet per mile, and there are no known surface faults in this area. Veins of gilsonite, a natural resinous hydrocarbon occasionally mined as a resource, occurs in the greater Uintah Basin though it is predominantly found on the eastern margin of the basin near the Colorado border. Vertical veins, generally between 2 feet to 6 feet wide but up to 28 feet wide, may extend many miles in length and occasionally extend as deep as 2,000 feet.

TABLE 2.1

GEOLOGIC SETTING

Blackjack Federal 10-5-9-17

Formation Name	Top (ft)	Base (ft)	TDS (mg/l)	Lithology
Uinta	0	1,471	< 10,000	Interbedded sand, shale,dolomite.
Uinta: Publication 92	0	249	< 10,000	Sand and shale.
Green River	1,471	6,062		Interbedded lacustrine sand, shale, carbonate and evaporate with some fluvial sand and shale.
Green River: Trona	2,852	2,917		Evaporite
Green River: Mahogany Bench	2,917	2,934		Shale
Green River: Garden Gulch Member No. 1	3,477	3,976		Lacustrine shale, sand, and carbonate.
Green River: Garden Gulch Member No. 2	3,976	4,640	20,337	Lacustrine shale, carbonate, some sand.
Green River: Douglas Creek Member	4,640	5,937	20,337	Interbedded lacustrine sand, shale, carbonate.
Green River: Basal Carbonate Member	5,937	6,062		Carbonate.

Proposed Injection Zone(s) (TABLE 2.2)

An injection zone is a geological formation, group of formations, or part of a formation that receives fluids through a well. The proposed injection zones are listed in TABLE 2.2.

Injection will occur into an injection zone that is separated from USDWs by a confining zone which is free of known open faults or fractures within the Area of Review.

The approved interval for enhanced recovery injection is located between the top of the Garden Gulch Member No. 2 (3,976 feet) and the top of the Wasatch Formation which has an estimated top of 6,062 feet.

Statement of Basis

TABLE 2.2
INJECTION ZONES
Blackjack Federal 10-5-9-17

Formation Name	Top (ft)	Base (ft)	TDS (mg/l)	Fracture Gradient (psi/ft)	Porosity	Exempted?*
Green River Formation: Garden Gulch & Douglas Creek Members	3,976	6,062	20,337	0.790		N/A

*** C - Currently Exempted**
E - Previously Exempted
P - Proposed Exemption
N/A - Not Applicable

Confining Zone(s) (TABLE 2.3)
A confining zone is a geological formation, part of a formation, or a group of formations that limits fluid movement above the injection zone. The confining zone or zones are listed in TABLE 2.3.

The Garden Gulch Member Confining Zone is located between the depths of 3,477 feet and 3,976 feet.

TABLE 2.3
CONFINING ZONES
Blackjack Federal 10-5-9-17

Formation Name	Formation Lithology	Top (ft)	Base (ft)
Green River	Interbedded limestone, sand and shale.	3,477	3,976

Underground Sources of Drinking Water (USDWs) (TABLE 2.4)
Aquifers or the portions thereof which contain less than 10,000 mg/l total dissolved solids (TDS) and are being or could in the future be used as a source of drinking water are considered to be USDWs. The USDWs in the area of this facility are identified in TABLE 2.4.

The State of Utah "Water Wells and Springs", http//NRWRT1.STATE.UT.US, identifies no public water supply wells within the one-quarter (1/4) mile Area-of-Review (AOR) around the Blackjack Federal No. 10-5-9-17.

Technical Publication No. 92: State of Utah, Department of Natural Resources, cites the base of Underground Sources of Drinking Water (USDW) in the Uinta Formation, approximately 249 feet from the surface.

Absent definitive analyses of water within the Uinta Formation (Surface to top of Green River Formation at 1,471 feet) the Uinta Formation is considered a potential USDW with total dissolved solids less than 10,000 mg/l.

TABLE 2.4
UNDERGROUND SOURCES OF DRINKING WATER (USDW)
Blackjack Federal 10-5-9-17

Formation Name	Formation Lithology	Top (ft)	Base (ft)	TDS (mg/l)
Uinta	Sand, shale and some limestone	0	1,471	< 10,000
Uinta: Publication 92	Sand and shale.	0	249	< 10,000

PART III. Well Construction (40 CFR 146.22)

The Blackjack Federal No. 10-5-9-17 was drilled to total depth of 6,015 feet (KB) in the Basal Carbonate Member of the Green River Formation.

Surface casing (8-5/8 inch) was set at a depth of 333 feet in a 12-1/4 inch hole using 160 sacks of Class "G" cement which was circulated to the surface.

Production casing (5-1/2 inch) was set at a depth of 5,985 feet (KB) in a 7-7/8 inch hole with 350 sacks of Premium Lite II and 400 sacks of 50/50 Pozmix. Well construction is considered adequate to protect all USDWs.

The EPA calculates top of cement (TOC) at 1,154 feet from the surface.

The Schematic Diagram shows the proposed-current injection perforations in the Garden Gulch and Douglas Creek Members of the Green River Formation. Additional perforations may be added at a later time between the depths of 4,092 feet and the top of the Wasatch Formation (Estimated to be 6,062 feet) provided that the operator first notifies the Director and later submits an updated Well Rework Record (EPA Form 7520-12) and schematic diagram.

The packer will be set no higher than 100 feet above the top perforation.

TABLE 3.1
WELL CONSTRUCTION REQUIREMENTS
Blackjack Federal 10-5-9-17

Casing Type	Hole Size (in)	Casing Size (in)	Cased Interval (ft)	Cemented Interval (ft)
Production	7.88	5.50	0 - 5,985	130 - 6,015
Surface	12.25	8.63	0 - 333	0 - 333

The approved well completion plan will be incorporated into the Permit as APPENDIX A and will be binding on the Permittee. Modification of the approved plan is allowed under 40 CFR 144.52(a)(1) provided written approval is obtained from the Director prior to actual modification.

Casing and Cementing (TABLE 3.1)

The well construction plan was evaluated and determined to be in conformance with standard practices and guidelines that ensure well injection does not result in the movement of fluids into USDWs. Well construction details for this "new" injection well is shown in TABLE 3.1.

Remedial cementing may be required if the casing cement is shown to be inadequate by cement bond log or other demonstration of Part II (External) mechanical integrity.

Tubing and Packer

Injection tubing is required to be installed from a packer up to the surface inside the well casing. The packer will be set above the uppermost perforation. The tubing and packer are designed to prevent injection fluid from coming into contact with the outermost casing.

Tubing-Casing Annulus (TCA)

The TCA allows the casing, tubing and packer to be pressure-tested periodically for mechanical integrity, and will allow for detection of leaks. The TCA will be filled with fresh water treated with a corrosion inhibitor or other fluid approved by the Director.

The tubing/casing annulus must be kept open at all times so that it can be monitored as required under the Permit.

Monitoring Devices

The permittee will be required to install and maintain wellhead equipment that allows for monitoring pressures and providing access for sampling the injected fluid. Required equipment may include but is not limited to: 1) shut-off valves located at the wellhead on the injection tubing and on the TCA; 2) a flow meter that measures the cumulative volume of injected fluid; 3) fittings or pressure gauges attached to the injection tubing and the TCA for monitoring the injection and TCA pressure; and 4) a tap on the injection line, isolated by shut-off valves, for sampling the injected fluid.

All sampling and measurement taken for monitoring must be representative of the monitored activity.

PART IV. Area of Review, Corrective Action Plan (40 CFR 144.55)

TABLE 4.1
AOR AND CORRECTIVE ACTION

Well Name	Type	Status (Abandoned Y/N)	Total Depth (ft)	TOC Depth (ft)	CAP Required (Y/N)
Blackjack Federal 9-5R-9-17	Producer	No	5,890	712	No
Federal 34-5H-9-17	Injector	No	6,067	710	No
GMB R-5-9-17	Producer	No	6,180	44	No
GMB R-5-9-17	Producer	No	6,180	44	No
GMB S-5-9-17	Producer	No	6,209	90	No
GMBU M-5-9-17	Producer	No	6,283	57	No
Monument Federal 23-5J-9-17	Producer	No	5,800	2,910	No
Monument Federal 24-5-9-17	Injector	No	5,700	2,525	No

TABLE 4.1 lists the wells in the Area of Review ("AOR") and shows the well type, operating status, depth, top of casing cement ("TOC") and whether a Corrective Action Plan ("CAP") is required for the well.

Area Of Review
Applicants for Class I, II (other than "existing" wells) or III injection well Permits are required to identify the location of all known wells within the injection well's Area of Review (AOR) which penetrate the injection zone, or in the case of Class II wells operating over the fracture pressure of the formation, all known wells within the area of review that penetrate formations which may be affected by increased pressure. Under 40 CFR 146.6 the AOR may be a fixed radius of not less than one quarter (1/4) mile or a calculated zone of endangering influence. For Area Permits, a fixed width of not less than one quarter (1/4) mile for the circumscribing area may be used.

Corrective Action Plan
For wells in the AOR which are improperly sealed, completed, or abandoned, the applicant shall develop a Corrective Action Plan (CAP) consisting of the steps or modifications that are necessary to prevent movement of fluid into USDWs.

The CAP will be incorporated into the Permit as APPENDIX F and become binding on the permittee.

Approved Injection Fluid

The approved injection fluid is limited to Class II injection well fluids pursuant to 40 CFR § 144.6(b). For disposal wells injecting water brought to the surface in connection with natural gas storage operations, or conventional oil or natural gas production, the fluid may be commingled and the well used to inject other Class II wastes such as drilling fluids and spent well completion, treatment and stimulation fluid. Injection of non-exempt wastes, including unused fracturing fluids or acids, gas plant cooling tower cleaning wastes, service wastes, and vacuum truck and drum rinsate from trucks and drums transporting or containing non-exempt waste, is prohibited.

The proposed injectate will be fluid from the Johnson Water District reservoir and/or water from the Green River blended with produced Green River Formation water from wells proximate to the Blackjack Federal 10-5-9-17.

Injection Pressure Limitation

Injection pressure, measured at the wellhead, shall not exceed a maximum calculated to assure that the pressure used during injection does not initiate new fractures or propagate existing fractures in the confining zones adjacent to the USDWs.

The applicant submitted injection fluid density and injection zone data which was used to calculate a formation fracture pressure and to determine the maximum allowable injection pressure (MAIP), as measured at the surface, for this Permit.

TABLE 5.1 lists the fracture gradient for the injection zone and the approved MAIP, determined according to the following formula:

$$FP = [fg - (0.433 * sg)] * d$$

FP = formation fracture pressure (measured at surface)
fg = fracture gradient (from submitted data or tests)
sg = specific gravity (of injected fluid)
d = depth to top of injection zone (or top perforation)

Injection Volume Limitation

Cumulative injected fluid volume limits are set to assure that injected fluids remain within the boundary of the exempted area. Cumulative injected fluid volume is limited when injection occurs into an aquifer that has been exempted from protection as a USDW.

There will be no restrictions on the cumulative volume of authorized fluid injected into the Green River Formation interval 3,976 feet to the top of the Wasatch Formation which is estimated to be 6,062 feet.

Mechanical Integrity (40 CFR 146.8)

An injection well has mechanical integrity if:

1. there is no significant leak in the casing, tubing, or packer (Part I); and
2. there is no significant fluid movement into a USDW through vertical channels adjacent to the injection well bore (Part II).

The Permit prohibits injection into a well which lacks mechanical integrity.

The Permit requires that the well demonstrate mechanical integrity prior to injection and periodically thereafter. A demonstration of mechanical integrity includes both internal (Part I) and external (Part II). The methods and frequency for demonstrating Part I and Part II mechanical integrity are dependent upon well-specific conditions as explained below.

Well construction and site-specific conditions dictate the following requirements for Mechanical Integrity (MI) demonstrations:

PART I MI: Internal MI will be demonstrated prior to beginning injection. Since this well is constructed with a standard casing, tubing, and packer configuration, a successful mechanical integrity test (MIT) is required to take place at least once every five (5) years. A demonstration of Part I MI is also required prior to resuming injection following any workover operation that affects the casing, tubing or packer. Part I MI may be demonstrated by a standard tubing-casing annulus pressure test using the maximum permitted injection pressure or 1000 psi, which ever is less, with a ten (10) percent or less pressure loss over thirty (30) minutes.

PART VI. Monitoring, Recordkeeping and Reporting Requirements

Injection Well Monitoring Program

At least once a year the permittee must analyze a sample of the injected fluid for total dissolved solids (TDS), specific conductivity, pH, and specific gravity. This analysis shall be reported to EPA annually as part of the Annual Report to the Director. Any time a new source of injected fluid is added, a fluid analysis shall be made of the new source.

Instantaneous injection pressure, injection flow rate, cumulative fluid volume and TCA pressures must be observed on a weekly basis. A recording, at least once every thirty (30) days, must be made of the injection pressure, annulus pressure, monthly injection flow rate and cumulative fluid volume. This information is required to be reported annually as part of the Annual Report to the Director.

PART VII. Plugging and Abandonment Requirements (40 CFR 146.10)

Plugging and Abandonment Plan

Prior to abandonment, the well shall be plugged in a manner that isolates the injection zone and prevents movement of fluid into or between USDWs, and in accordance with any applicable Federal, State or local law or regulation. Tubing, packer and other downhole apparatus shall be removed. Cement with additives such as accelerators and retarders that control or enhance cement properties may be used for plugs; however, volume-extending additives and gel cements are not approved for plug use. Plug placement shall be verified by tagging. Plugging gel of at least 9.2 lb/gal shall be placed between all plugs. A minimum 50 ft surface plug shall be set inside and outside of the surface casing to seal pathways for fluid migration into the subsurface. Within sixty (60) days after plugging the owner or operator shall submit Plugging Record (EPA Form 7520 13) to the Director. The Plugging Record must be certified as accurate and complete by the person responsible for the plugging operation. The plugging and abandonment plan is described in Appendix E of the Permit.

PART VIII. Financial Responsibility (40 CFR 144.52)

Demonstration of Financial Responsibility

The permittee is required to maintain financial responsibility and resources to close, plug, and abandon the underground injection operation in a manner prescribed by the Director. The permittee shall show evidence of such financial responsibility to the Director by the submission of a surety bond, or other adequate assurance such as financial statements or other materials acceptable to the Director. The Regional Administrator may, on a periodic basis, require the holder of a lifetime permit to submit a revised estimate of the resources needed to plug and abandon the well to reflect inflation of such costs, and a revised demonstration of financial responsibility if necessary. Initially, the operator has chosen to demonstrate financial responsibility with:

A demonstration of Financial Responsibility in the amount of $42,000 has been reviewed and approved by the EPA on December 21, 2011.

The Director may revise the amount required, and may require the Permittee to obtain and provide updated estimates of plugging and abandonment costs according to the approved Plugging and Abandonment Plan.

Evidence of continuing financial responsibility is required to be submitted to the Director annually.

Sundry Number: 33206 API Well Number: 43013325530000

STATE OF UTAH DEPARTMENT OF NATURAL RESOURCES DIVISION OF OIL, GAS, AND MINING	**FORM 9**
	5.LEASE DESIGNATION AND SERIAL NUMBER: UTU-74808
SUNDRY NOTICES AND REPORTS ON WELLS Do not use this form for proposals to drill new wells, significantly deepen existing wells below current bottom-hole depth, reenter plugged wells, or to drill horizontal laterals. Use APPLICATION FOR PERMIT TO DRILL form for such proposals.	**6. IF INDIAN, ALLOTTEE OR TRIBE NAME:**
	7.UNIT or CA AGREEMENT NAME: GMBU (GRRV)
1. TYPE OF WELL Oil Well	**8. WELL NAME and NUMBER:** BLACKJACK FED 10-5-9-17
2. NAME OF OPERATOR: NEWFIELD PRODUCTION COMPANY	**9. API NUMBER:** 43013325530000
3. ADDRESS OF OPERATOR: Rt 3 Box 3630 , Myton, UT, 84052 **PHONE NUMBER:** 435 646-4825 Ext	**9. FIELD and POOL or WILDCAT:** MONUMENT BUTTE
4. LOCATION OF WELL **FOOTAGES AT SURFACE:** 1676 FSL 1982 FEL **QTR/QTR, SECTION, TOWNSHIP, RANGE, MERIDIAN:** Qtr/Qtr: NWSE Section: 05 Township: 09.0S Range: 17.0E Meridian: S	**COUNTY:** DUCHESNE **STATE:** UTAH

11. CHECK APPROPRIATE BOXES TO INDICATE NATURE OF NOTICE, REPORT, OR OTHER DATA

TYPE OF SUBMISSION	TYPE OF ACTION		
☐ NOTICE OF INTENT Approximate date work will start:	☐ ACIDIZE	☐ ALTER CASING	☐ CASING REPAIR
✓ SUBSEQUENT REPORT Date of Work Completion: 12/12/2012	☐ CHANGE TO PREVIOUS PLANS	☐ CHANGE TUBING	☐ CHANGE WELL NAME
	✓ CHANGE WELL STATUS	☐ COMMINGLE PRODUCING FORMATIONS	✓ CONVERT WELL TYPE
☐ SPUD REPORT Date of Spud:	☐ DEEPEN	☐ FRACTURE TREAT	☐ NEW CONSTRUCTION
	☐ OPERATOR CHANGE	☐ PLUG AND ABANDON	☐ PLUG BACK
☐ DRILLING REPORT Report Date:	☐ PRODUCTION START OR RESUME	☐ RECLAMATION OF WELL SITE	☐ RECOMPLETE DIFFERENT FORMATION
	☐ REPERFORATE CURRENT FORMATION	☐ SIDETRACK TO REPAIR WELL	☐ TEMPORARY ABANDON
	☐ TUBING REPAIR	☐ VENT OR FLARE	☐ WATER DISPOSAL
	☐ WATER SHUTOFF	☐ SI TA STATUS EXTENSION	☐ APD EXTENSION
	☐ WILDCAT WELL DETERMINATION	✓ OTHER	OTHER: New Perforations

12. DESCRIBE PROPOSED OR COMPLETED OPERATIONS. Clearly show all pertinent details including dates, depths, volumes, etc.

The subject well has been converted from a producing oil well to an injection well on 12/12/2012. New interval added: 5070-5080' 3 JSPF. On 12/04/2012 Jason Deardorff with the EPA was contacted concerning the initial MIT on the above listed well. On 12/12/2012 the casing was pressured up to 1865 psig and charted for 30 minutes with no pressure loss. The well was not injecting during the test. The tubing pressure was 450 psig during the test. There was not an EPA representative available to witness the test. EPA# UT22197-09492

Accepted by the Utah Division of Oil, Gas and Mining
FOR RECORD ONLY
December 24, 2012

NAME (PLEASE PRINT) Lucy Chavez-Naupoto	**PHONE NUMBER** 435 646-4874	**TITLE** Water Services Technician
SIGNATURE N/A		**DATE** 12/19/2012

RECEIVED: Dec. 19, 2012

Mechanical Integrity Test
Casing or Annulus Pressure Mechanical Integrity Test

U.S. Environmental Protection Agency
Underground Injection Control Program
999 18th Street, Suite 500 Denver, CO 80202-2466

EPA Witness: ______________ Date: 12 / 12 / 12
Test conducted by: Troy Lazenby
Others present: ______________

UT22228-09492

Well Name: Blackjack Federal 10-5-9-17 Type: ER SWD Status: AC TA UC
Field: Monument Butte
Location: NW/SE Sec: 5 T 9S N/(S) R 17 (E)/W County: Duchense State: UT
API 43-013-32553
Operator: Dow Trant
Last MIT: / / Maximum Allowable Pressure: ______ PSIG

Is this a regularly scheduled test? [ ] Yes [✓] No
Initial test for permit? [✓] Yes [ ] No
Test after well rework? [✓] Yes [ ] No
Well injecting during test? [ ] Yes [✓] No If Yes, rate: ______ bpd

Pre-test casing/tubing annulus pressure: 1865 / 450 psig

MIT DATA TABLE	Test #1	Test #2	Test #3
TUBING	***PRESSURE***		
Initial Pressure	450 psig	psig	psig
End of test pressure	psig	psig	psig
CASING / TUBING	***ANNULUS***	***PRESSURE***	
0 minutes	1865 psig	psig	psig
5 minutes	1865 psig	psig	psig
10 minutes	1865 psig	psig	psig
15 minutes	1865 psig	psig	psig
20 minutes	1865 psig	psig	psig
25 minutes	1865 psig	psig	psig
30 minutes	1865 psig	psig	psig
____ minutes	psig	psig	psig
____ minutes	psig	psig	psig
RESULT	[.] Pass [ ] Fail	[ ] Pass [ ] Fail	[ ] Pass [ ] Fail

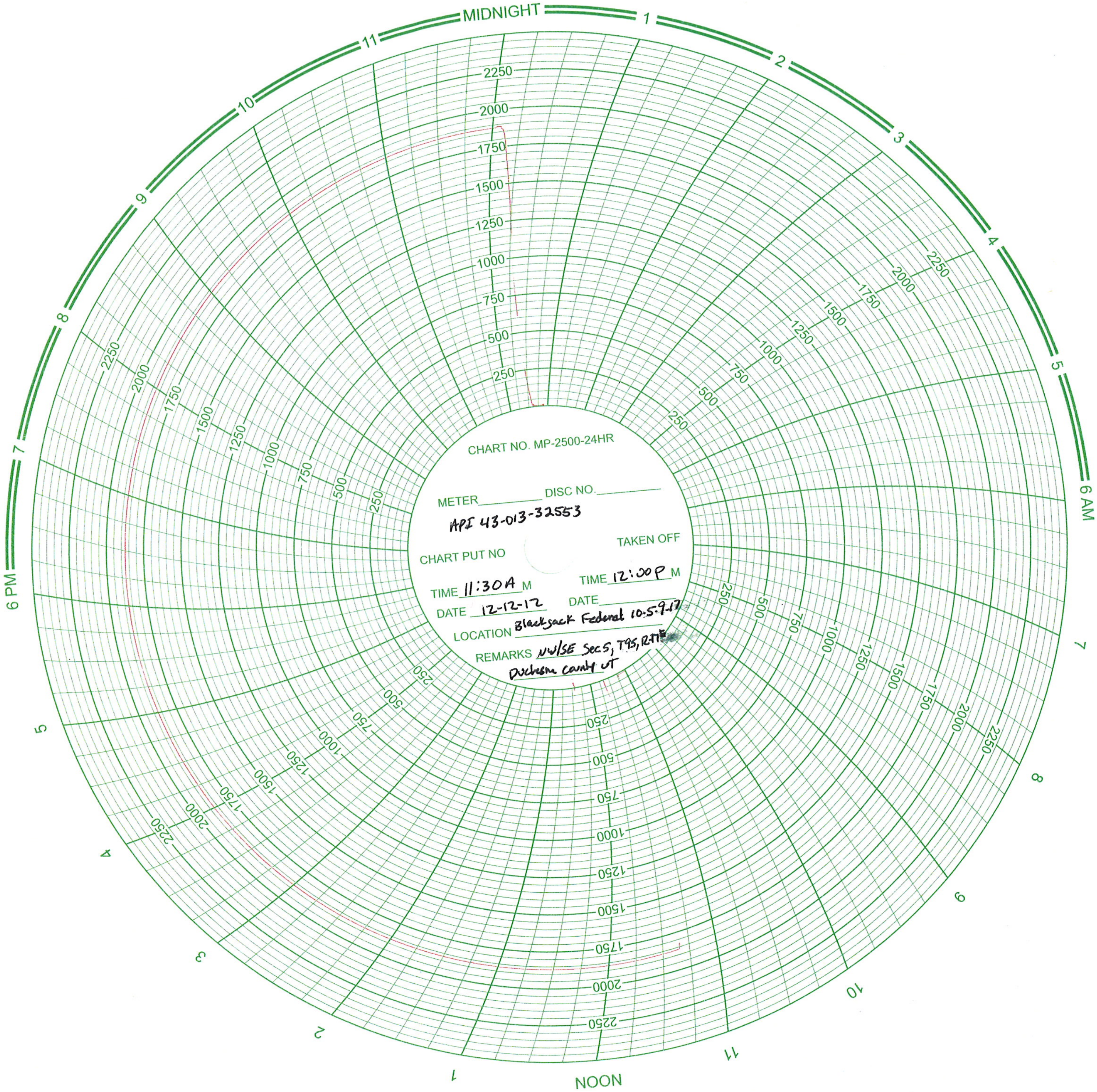
Does the annulus pressure build back up after the test ? [ ] Yes [ ] No

MECHANICAL INTEGRITY PRESSURE TEST

Additional comments for mechanical integrity pressure test, such as volume of fluid added to annulus and bled back at end of test, reason for failing test (casing head leak, tubing leak, other), etc.:

Signature of Witness: [signature]

Sundry Number: 33206 API Well Number: 43013325530000



Daily Activity Report

Format For Sundry

BLACKJACK 10-5-9-17

10/1/2012 To 2/28/2013

12/4/2012 Day: 1 **Conversion**

Stone #10 on 12/4/2012 - MIRU - MIRU Flush Csg W/ 60 BBLs - MIRU Flush Csg W/ 60 BBLs
Daily Cost: $0
Cumulative Cost: $1,993

12/5/2012 Day: 2 **Conversion**

Stone #10 on 12/5/2012 - POOH Flush & LD Rods & Pump. POOH Breaking & Doping Collars. - Crew travel. Safety Meeting , JSA. - RU Hot Oiler Pump 60 BBls Down Csg. Unseat Pump Flush Tbg W/ 40 BBls. Sfot Set pump. Fill Tbg W/ 15 BBls Blew Hole In Tbg @ 2300psi. - POOH. Flush & LD 1-1/2 Polish Rod, 1 3/4 Pony Rod, 100 3/4" 4per, 98 3/4 slick, 23 3/4 4per, 6 1-1/2 Sinker Bars, Pump. - POOH breaking, Doping & Tallying 121 Jts. Flush Csg w/ 60 bbls. - Crew travel. Safety Meeting , JSA. - RU Hot Oiler Pump 60 BBls Down Csg. Unseat Pump Flush Tbg W/ 40 BBls. Sfot Set pump. Fill Tbg W/ 15 BBls Blew Hole In Tbg @ 2300psi. - POOH. Flush & LD 1-1/2 Polish Rod, 1 3/4 Pony Rod, 100 3/4" 4per, 98 3/4 slick, 23 3/4 4per, 6 1-1/2 Sinker Bars, Pump. - POOH breaking, Doping & Tallying 121 Jts. Flush Csg w/ 60 bbls.
Daily Cost: $0
Cumulative Cost: $9,673

12/7/2012 Day: 3 **Conversion**

Stone #10 on 12/7/2012 - POOH W/ Tbg. Perforate A-1 Formation. PU & TIH W/ N-80 Tbg. Set RBP Break Down Formation. NU Frac Valve - Fill Tbg w/. 15 bblsl & Press test RBP To 3000 psi. Break Down A-1 Formation @ 3250 psi inject 1/2 BPM @ 1700psi. W/ 4 bbls. Release PKR PU & NU Frac Valve. CWI - Tally & PU 160 Jts, PSN, 1 Jt, PKR, 4' X 2-7/8 pup, RH, RBP, Set RBP @ 5095' POOH W/ 2jts POOH & LD 2 jts, Set PKR @ 5029' - Tally & PU 160 Jts, PSN, 1 Jt, PKR, 4' X 2-7/8 pup, RH, RBP, Set RBP @ 5095' POOH W/ 2jts POOH & LD 2 jts, Set PKR @ 5029' - Fill Tbg w/. 15 bblsl & Press test RBP To 3000 psi. Break Down A-1 Formation @ 3250 psi inject 1/2 BPM @ 1700psi. W/ 4 bbls. Release PKR PU & NU Frac Valve. CWI - RU Perforators RIH W/ 3-1/8" Csg Guns 3 SPF & Perfroate A-1 formation From 5070-80' (30 Holes) POOH & RD Perforators - Finish POOH, LD 51 Jts Tbg & BHA (Found Hole in Jt #139) - RU Perforators RIH W/ 3-1/8" Csg Guns 3 SPF & Perfroate A-1 formation From 5070-80' (30 Holes) POOH & RD Perforators - Crew Travel. Safety Meeting. JSA - Finish POOH, LD 51 Jts Tbg & BHA (Found Hole in Jt #139) - Crew Travel. Safety Meeting. JSA
Daily Cost: $0
Cumulative Cost: $33,410

12/12/2012 Day: 7 **Conversion**

Rigless on 12/12/2012 - Conduct initial MIT - NU Frac Valve Set PKR @ 5029'. RU Pump & Lines fill Csg W/ 35 BBls. RU Baker Hughes. - NU Frac Valve Set PKR @ 5029'. RU Pump & Lines fill Csg W/ 35 BBls. RU Baker Hughes. - NU Frac Valve Set PKR @ 5029'. RU Pump & Lines fill Csg W/ 35 BBls. RU Baker Hughes. - NU Frac Valve Set PKR @ 5029'. RU Pump & Lines fill Csg W/ 35 BBls. RU Baker Hughes. - Crew travel. Safety Meeting JSA. - Crew travel. Safety Meeting JSA. - Crew travel. Safety Meeting JSA. - Crew travel. Safety Meeting JSA. - On 12/04/2012 Jason Deardorff with the EPA was contacted concerning the initial MIT on the above listed well. On 12/12/2012 the casing was pressured up to 1865 psig and charted for 30 minutes with no pressure loss. The well was not injecting during the test. The tubing pressure was 450 psig during the test. There was not an EPA representative available to witness the test. 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2392 psi. Max press 5450 psi. Avg press 4160 psi. Max rate 17 BPM. Avg rate 15.6 BPM. 32,182# 20/40 Sand in formation. 462 Total bbls pumped - Safety Meeting . JSA.Press test To 7200 psi. Open Well @ 0 psi. Pump 5 bbls fresh Water @ 1750 psi @ 2 BPM. Pump 6 bbls 15% HCL. 92 bbls Fresh water To Get Link & Acid On Perfs, Pump 29 bbls Lighting 17 Pad. 93 bbls 2# 20/40 sand (Ramped) 204 bbls 4# 20/40 sand Ramped. 30 bbls Fresh water Flush. ISIP 2392 psi. Max press 5450 psi. Avg press 4160 psi. Max rate 17 BPM. Avg rate 15.6 BPM. 32,182# 20/40 Sand in formation. 462 Total bbls pumped - Safety Meeting . JSA.Press test To 7200 psi. Open Well @ 0 psi. Pump 5 bbls fresh Water @ 1750 psi @ 2 BPM. Pump 6 bbls 15% HCL. 92 bbls Fresh water To Get Link & Acid On Perfs, Pump 29 bbls Lighting 17 Pad. 93 bbls 2# 20/40 sand (Ramped) 204 bbls 4# 20/40 sand Ramped. 30 bbls Fresh water Flush. ISIP 2392 psi. Max press 5450 psi. Avg press 4160 psi. Max rate 17 BPM. 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Press up Tbg to 3500 psi CWI. - Fill Tbg w/ 10 bbls prees test Tbg to 3120 psi. lost 400 psi. Press up Tbg to 3500 psi CWI. - Fill Tbg w/ 10 bbls prees test Tbg to 3120 psi. lost 400 psi. Press up Tbg to 3500 psi CWI. - RU Sand Line RIH W/ Over Shot. Retrive SV. Drop New SV pump 25 bbls down Tbg Chase SV to bottom w/ Sand line. POOH W/ Sand Line. - RU Sand Line RIH W/ Over Shot. Retrive SV. Drop New SV pump 25 bbls down Tbg Chase SV to bottom w/ Sand line. POOH W/ Sand Line. - RU Sand Line RIH W/ Over Shot. Retrive SV. Drop New SV pump 25 bbls down Tbg Chase SV to bottom w/ Sand line. POOH W/ Sand Line. - RU Sand Line RIH W/ Over Shot. Retrive SV. Drop New SV pump 25 bbls down Tbg Chase SV to bottom w/ Sand line. POOH W/ Sand Line. - Press up Tbg to 3180 psi lost 240 psi 1-1/2 hrs. - Press up Tbg to 3180 psi lost 240 psi 1-1/2 hrs. - Press up Tbg to 3180 psi lost 240 psi 1-1/2 hrs. - Press up Tbg to 3180 psi lost 240 psi 1-1/2 hrs. - Fill Tbg w/ 10 BBls Press test Tbg to 3040 psi. Lost 680 psi 1-1/2 Hrs - Fill Tbg w/ 10 BBls Press test Tbg to 3040 psi. Lost 680 psi 1-1/2 Hrs - Fill Tbg w/ 10 BBls Press test Tbg to 3040 psi. Lost 680 psi 1-1/2 Hrs - Fill Tbg w/ 10 BBls Press test Tbg to 3040 psi. Lost 680 psi 1-1/2 Hrs - Safety Meeting . JSA.Press test To 7200 psi. Open Well @ 0 psi. Pump 5 bbls fresh Water @ 1750 psi @ 2 BPM. Pump 6 bbls 15% HCL. 92 bbls Fresh water To Get Link & Acid On Perfs, Pump 29 bbls Lighting 17 Pad. 93 bbls 2# 20/40 sand (Ramped) 204 bbls 4# 20/40 sand Ramped. 30 bbls Fresh water Flush. ISIP 2392 psi. Max press 5450 psi. Avg press 4160 psi. Max rate 17 BPM. Avg rate 15.6 BPM. 32,182# 20/40 Sand in formation. 462 Total bbls pumped - Safety Meeting . JSA.Press test To 7200 psi. Open Well @ 0 psi. Pump 5 bbls fresh Water @ 1750 psi @ 2 BPM. Pump 6 bbls 15% HCL. 92 bbls Fresh water To Get Link & Acid On Perfs, Pump 29 bbls Lighting 17 Pad. 93 bbls 2# 20/40 sand (Ramped) 204 bbls 4# 20/40 sand Ramped. 30 bbls Fresh water Flush. 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Avg rate 15.6 BPM. 32,182# 20/40 Sand in formation. 462 Total bbls pumped - RU Hot Oiler flush tbg w/ 40 bbls drop Standing

Valve pump 20 bbls RU & RIH w/ Sand Line Tap SV. POOH W/ Sand Line. - RU Hot Oiler flush tbg w/ 40 bbls drop Standing Valve pump 20 bbls RU & RIH w/ Sand Line Tap SV. POOH W/ Sand Line. - RU Hot Oiler flush tbg w/ 40 bbls drop Standing Valve pump 20 bbls RU & RIH w/ Sand Line Tap SV. POOH W/ Sand Line. - RU Hot Oiler flush tbg w/ 40 bbls drop Standing Valve pump 20 bbls RU & RIH w/ Sand Line Tap SV. POOH W/ Sand Line. - Crew Travel. Safety meeting. JSA. - Crew Travel. Safety meeting. JSA. - Crew Travel. Safety meeting. JSA. - Crew Travel. Safety meeting. JSA. - RIH W/ Re-entry Guide, XNN Nipple, 4" Pup, XO 2-7/8 X 2/3/8, PKR, RH, S/N, 121 jts J-55 Tbg. Drain Pump & Lines Shut Well In for Week End. EOT @ 4061'. Call Runners release N-80 Tbg String. - RIH W/ Re-entry Guide, XNN Nipple, 4" Pup, XO 2-7/8 X 2/3/8, PKR, RH, S/N, 121 jts J-55 Tbg. Drain Pump & Lines Shut Well In for Week End. EOT @ 4061'. Call Runners release N-80 Tbg String. - RIH W/ Re-entry Guide, XNN Nipple, 4" Pup, XO 2-7/8 X 2/3/8, PKR, RH, S/N, 121 jts J-55 Tbg. Drain Pump & Lines Shut Well In for Week End. EOT @ 4061'. Call Runners release N-80 Tbg String. - RIH W/ Re-entry Guide, XNN Nipple, 4" Pup, XO 2-7/8 X 2/3/8, PKR, RH, S/N, 121 jts J-55 Tbg. Drain Pump & Lines Shut Well In for Week End. EOT @ 4061'. Call Runners release N-80 Tbg String.
Finalized
Daily Cost: $0
Cumulative Cost: $195,361

Pertinent Files: Go to File List

FORM 9

STATE OF UTAH
DEPARTMENT OF NATURAL RESOURCES
DIVISION OF OIL, GAS, AND MINING

5.LEASE DESIGNATION AND SERIAL NUMBER: UTU-74808

SUNDRY NOTICES AND REPORTS ON WELLS

Do not use this form for proposals to drill new wells, significantly deepen existing wells below current bottom-hole depth, reenter plugged wells, or to drill horizontal laterals. Use APPLICATION FOR PERMIT TO DRILL form for such proposals.

6. IF INDIAN, ALLOTTEE OR TRIBE NAME:

7.UNIT or CA AGREEMENT NAME: GMBU (GRRV)

1. TYPE OF WELL Water Injection Well

8. WELL NAME and NUMBER: BLACKJACK FED 10-5-9-17

2. NAME OF OPERATOR: NEWFIELD PRODUCTION COMPANY

9. API NUMBER: 43013325530000

3. ADDRESS OF OPERATOR: Rt 3 Box 3630 , Myton, UT, 84052

PHONE NUMBER: 435 646-4825 Ext

9. FIELD and POOL or WILDCAT: MONUMENT BUTTE

4. LOCATION OF WELL
FOOTAGES AT SURFACE: 1676 FSL 1982 FEL
QTR/QTR, SECTION, TOWNSHIP, RANGE, MERIDIAN: Qtr/Qtr: NWSE Section: 05 Township: 09.0S Range: 17.0E Meridian: S

COUNTY: DUCHESNE

STATE: UTAH

11. CHECK APPROPRIATE BOXES TO INDICATE NATURE OF NOTICE, REPORT, OR OTHER DATA

TYPE OF SUBMISSION	TYPE OF ACTION		
☐ NOTICE OF INTENT Approximate date work will start:	☐ ACIDIZE	☐ ALTER CASING	☐ CASING REPAIR
✓ SUBSEQUENT REPORT Date of Work Completion: 1/24/2013	☐ CHANGE TO PREVIOUS PLANS	☐ CHANGE TUBING	☐ CHANGE WELL NAME
	✓ CHANGE WELL STATUS	☐ COMMINGLE PRODUCING FORMATIONS	✓ CONVERT WELL TYPE
☐ SPUD REPORT Date of Spud:	☐ DEEPEN	☐ FRACTURE TREAT	☐ NEW CONSTRUCTION
	☐ OPERATOR CHANGE	☐ PLUG AND ABANDON	☐ PLUG BACK
☐ DRILLING REPORT Report Date:	☐ PRODUCTION START OR RESUME	☐ RECLAMATION OF WELL SITE	☐ RECOMPLETE DIFFERENT FORMATION
	☐ REPERFORATE CURRENT FORMATION	☐ SIDETRACK TO REPAIR WELL	☐ TEMPORARY ABANDON
	☐ TUBING REPAIR	☐ VENT OR FLARE	☐ WATER DISPOSAL
	☐ WATER SHUTOFF	☐ SI TA STATUS EXTENSION	☐ APD EXTENSION
	☐ WILDCAT WELL DETERMINATION	☐ OTHER	OTHER:

12. DESCRIBE PROPOSED OR COMPLETED OPERATIONS. Clearly show all pertinent details including dates, depths, volumes, etc.

The above reference well was put on injection at 11:45 AM on 01/24/2013. EPA # UT22197-09492

Accepted by the
Utah Division of
Oil, Gas and Mining
FOR RECORD ONLY
February 14, 2013

NAME (PLEASE PRINT)	PHONE NUMBER	TITLE
Lucy Chavez-Naupoto	435 646-4874	Water Services Technician

SIGNATURE	DATE
N/A	1/24/2013

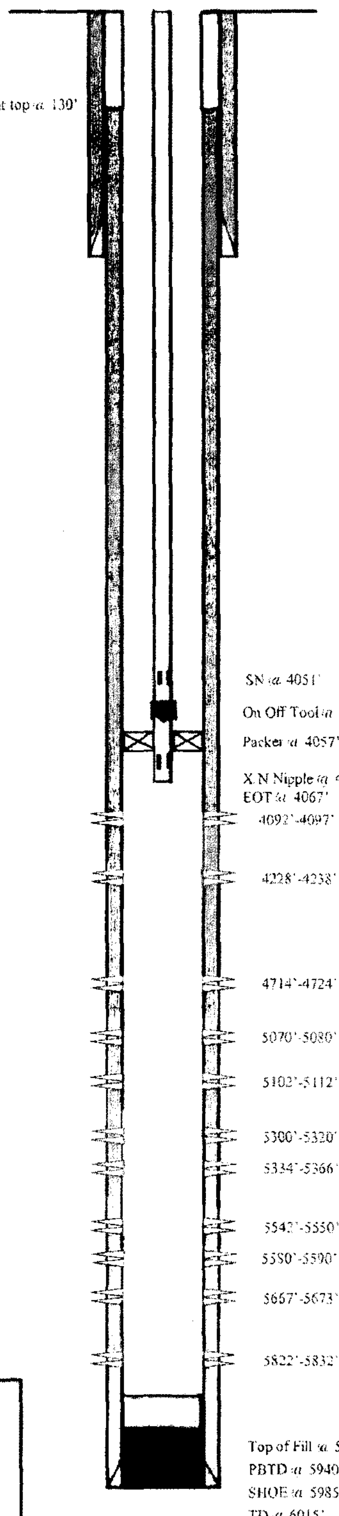
Spud Date: 12 1 04

Put on Production: 1 11 05

GL: 5251' KB: 5263'

Blackjack Federal 10-5-9-17

Injection Wellbore
Diagram



SURFACE CASING

CSG SIZE: 8-5 8"

GRADE: J-55

WEIGHT: 24#

LENGTH: 8 jts (323.05')

DEPTH LANDED: 333.05'

HOLE SIZE: 12-1 4"

CEMENT DATA: 160 sxs Class G cement. Est 4 bbls cmt to surface.

PRODUCTION CASING

CSG SIZE: 5-1 2"

GRADE: J-55

WEIGHT: 15.5#

LENGTH: 142 jts. (5988.91')

DEPTH LANDED: 5985.35' KB

HOLE SIZE: 7-7 8"

CEMENT DATA: 350 sxs Premlite II & 400 sxs 50 50 POZ.

CEMENT TOP AT: 130'

TUBING

SIZE GRADE WT.: 2-7 8" J-55 6.5#

NO. OF JOINTS: 121 jts (4038.6')

SEATING NIPPLE: 2-7 8" (1.10')

SN LANDED AT: 4050.6' KB

ON OFF TOOL AT: 4051.7'

ARROW #1 PACKER CE AT: 4056.68'

XO 2-3 8 x 2-7 8 J-55 AT: 4060.4'

TBG PUP 2-3 8 J-55 AT: 4060.9'

X N NIPPLE AT: 4065'

TOTAL STRING LENGTH: EOT @ 4067'

FRAC JOB

1 04 05	5822'-5832'	**Frac CP5 sands as follows:** 18,712# 20 40 sand in 268 bbls Lightning 17 frac fluid. Treated @ avg press of 2130 psi w avg rate of 24.5 BPM. ISIP 2145 psi. Calc. flush: 5820 gal. Actual flush: 5859 gal.
1 04 05	5542'-5673'	**Frac CP3, 1 & .5 sands as follows:** 64,105# 20 40 sand in 524 bbls Lightning 17 frac fluid. Treated @ avg press of 1956 psi w avg rate of 24.5 BPM. ISIP 1990 psi. Calc. flush: 5540 gal. Actual flush: 5573 gal
1 04 05	5300'-5366'	**Frac LODC sands as follows:** 199,147# 20/40 sand in 1337 bbls Lightning 17 frac fluid. Treated @ avg press of 1684 psi w avg rate of 24.5 BPM. ISIP 2100 psi. Calc. flush: 5298 gal. Actual flush: 5330 gal.
1 04 05	5102'-5112'	**Frac A3 sands as follows:** 44,330# 20 40 sand in 411 bbls Lightning 17 frac fluid. Treated @ avg press of 1968 psi w/avg rate of 24.5 BPM. ISIP 2300 psi. Calc flush: 5100 gal. Actual flush: 5124 gal.
1 05 05	4714'-4724'	**Frac D2 sands as follows:** 19,177# 20/40 sand in 241 bbls Lightning 17 frac fluid. Treated @ avg press of 1791 psi w avg rate of 24.3 BPM. ISIP 1850 psi. Calc. flush: 4712 gal. Actual flush: 4725 gal.
1 05 05	4228'-4238'	**Frac GB6 sands as follows:** 63,938# 20 40 sand in 493 bbls Lightning 17 frac fluid. Treated @ avg press of 2267 psi w avg rate of 24.5 BPM. ISIP 1780 psi. Calc. flush. 4226 gal. Actual flush: 4259 gal.
1 05 05	4092'-4097'	**Frac GB2 sands as follows:** 14,210# 20 40 sand in 230 bbls Lightning 17 frac fluid. Treated @ avg press of 2447 psi w/avg rate of 24.6 BPM. ISIP 1970 psi. Calc. flush: 4090 gal. Actual flush: 4003 gal.
12 07 12	5070-5080'	**Frac A1 sands as follows:** 32182# 20/40 sand in 328 bbls Lightning 17 frac fluid.
12/12/12		**Convert to Injection Well**
12/12/12		**Conversion MIT Finalized** - update tbg detail

PERFORATION RECORD

12/30/04	5822'-5832'	4 JSPF	40 holes
01 04 05	5667'-5673'	4 JSPF	24 holes
01 04 05	5580'-5590'	4 JSPF	40 holes
01 04 05	5542'-5550'	4 JSPF	32 holes
01 04 05	5334'-5366'	2 JSPF	64 holes
01 04 05	5300'-5320'	2 JSPF	40 holes
01 04 05	5102'-5112'	4 JSPF	40 holes
01 04 05	4714'-4724'	4 JSPF	40 holes
01 05 05	4228'-4238'	4 JSPF	40 holes
01 05 05	4092'-4097'	4 JSPF	20 holes
12/06/12	5070-5080'	3 JSPF	30 holes

NEWFIELD

Blackjack Federal 10-5-9-17

1676' FSL & 1982' FEL

NWSE Section 5-T9S-R17E

Duchesne Co. Utah

API #43-013-32553; Lease #UTU-74808

LCN 12/14/12