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

001

APPLICATION FOR PERMIT TO DRILL OR REENTER

5. Lease Serial No. UTU-70821

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

1a. Type of Work: [x] DRILL [ ] REENTER

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

1b. Type of Well: [x] Oil Well [ ] Gas Well [ ] Other [x] Single Zone [ ] Multiple Zone

8. Lease Name and Well No. BlackJack Federal 12-10-9-17

2. Name of Operator
Inland Production Company

9. API Well No. 43-013-32505

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/SW 1999' FSL 730' FWL 4432883Y 40.04375
At proposed prod. zone 585404X -109.99888

11. Sec., T., R., M., or Blk. and Survey or Area
NW/SW Sec. 10, T9S R17E

14. Distance in miles and direction from nearest town or post office*
Approximatley 14.3 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. 730' f/lse, 1999' f/unit	16. No. of Acres in lease 240.00	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. 1524'	19. Proposed Depth 6500'	20. BLM/BIA Bond No. on file #4488944

21. Elevations (Show whether DF, KDB, RT, GL, etc.)	22. Approximate date work will start*	23. Estimated duration
5172' GR	1st Quarter 2004	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 10/2/03

Title
Regulatory Specialist

Approved by *(Signature)* Bradley G. Hill | Name *(Printed/Typed)* BRADLEY G. HILL | Date 10-14-03

Title | Office ENVIRONMENTAL SCIENTIST III

Federal Approval of this Action is Necessary

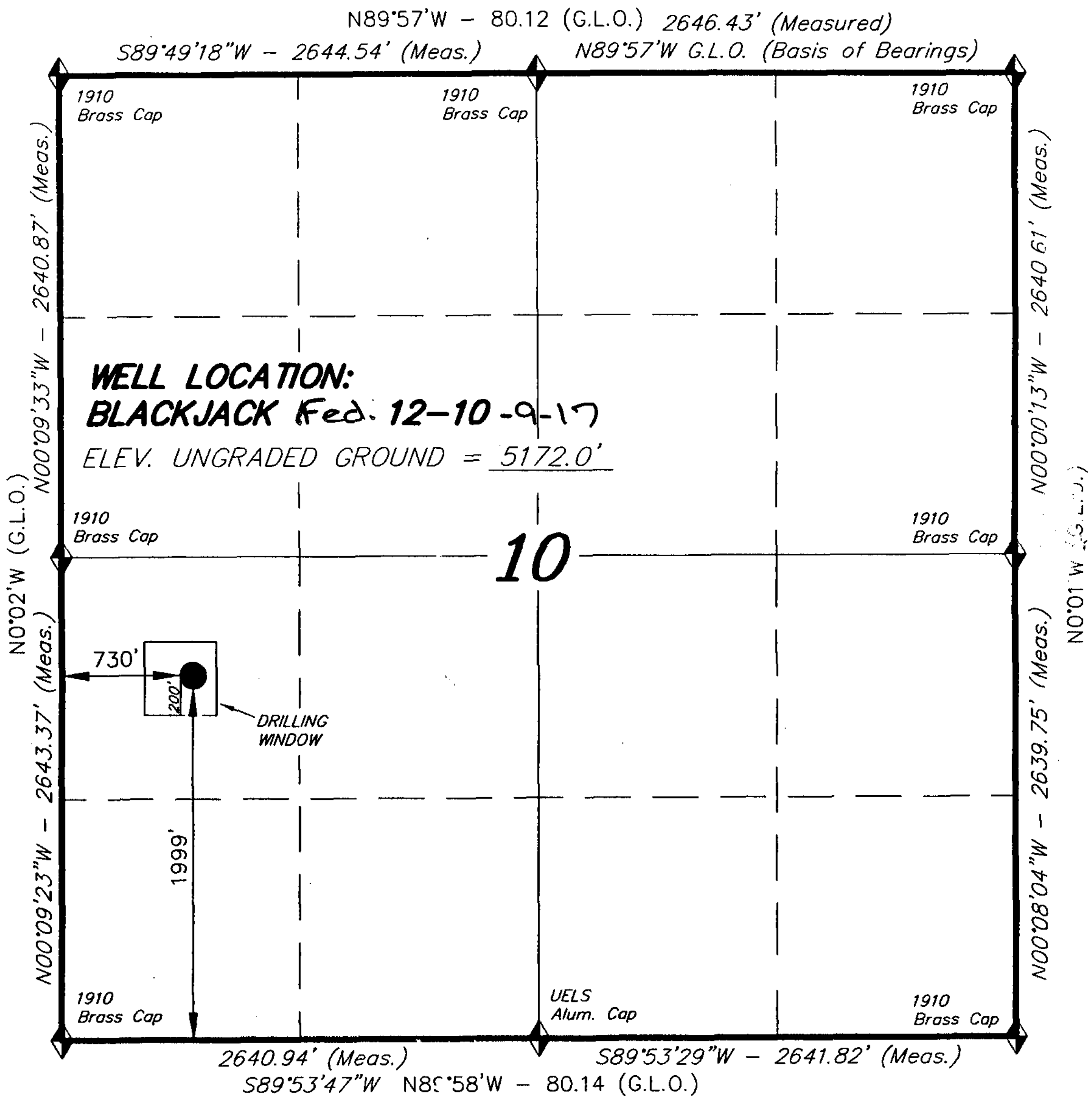
Application approval does not warrant or certify the the applicant holds legal or equitable title to those rights in the subject lease which would entitle the applicant to conduct operations thereon.
Conditions of approval, if any, are attached.

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
OCT 03 2003
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 (PARIETTE DRAW SW)

INLAND PRODUCTION COMPANY

WELL LOCATION, BLACKJACK Fed. 12-10-9-17 LOCATED AS SHOWN IN THE NW 1/4 SW 1/4 OF SECTION 10, T9S, R17E, S.L.B.&M. DUCHESNE COUNTY, UTAH.

N

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: 8-21-03	DRAWN BY: R.V.C.
NOTES:	FILE #

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)

October 14, 2003

Memorandum

To: Assistant District Manager Minerals, Vernal District

From: Michael Coulthard, Petroleum Engineer

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

Pursuant to email between Diana Mason, 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 Blackjack Unit, Duchesne County, Utah.

API #	WELL NAME	LOCATION
(Proposed PZ Green River)		
43-013-32500	Blackjack Federal 16-03-9-17	Sec 3 T09S R17E 0545 FSL 0596 FEL
43-013-32501	Blackjack Federal 15-03-9-17	Sec 3 T09S R17E 0762 FSL 1838 FEL
43-013-32503	Blackjack Federal 15-10-9-17	Sec 10 T09S R17E 0575 FSL 2082 FEL
43-013-32504	Blackjack Federal 13-10-9-17	Sec 10 T09S R17E 0300 FSL 0692 FWL
43-013-32505	Blackjack Federal 12-10-9-17	Sec 10 T09S R17E 1999 FSL 0730 FWL
43-013-32506	Blackjack Federal 11-10-9-17	Sec 10 T09S R17E 1813 FSL 2068 FWL
43-013-32507	Blackjack Federal 4-10-9-17	Sec 10 T09S R17E 0398 FNL 0520 FWL
43-013-32508	Blackjack Federal 2-10-9-17	Sec 10 T09S R17E 0660 FNL 1980 FEL

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

/s/ Michael L. Coulthard

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

MCoulthard:mc:10-14-3

PRODUCTION COMPANY
A Subsidiary of Inland Resources Inc.

October 2, 2003

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

RE: Applications for Permit to Drill: Blackjack Federal 2-10-9-17, 4-10-9-17, 11-10-9-17, 12-10-9-17, 13-10-9-17, 15-10-9-17, and Federal 9-10-9-17.

Dear Diana:

Enclosed find APD's on the above referenced wells. The 4-10-9-17 and 13-10-9-17 are Exception Locations. You will be receiving Exception Locations Letters from our Land Department shortly. 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
OCT 03 2003
DIV. OF OIL, GAS & MINING

Inland Production Company Field Office • Route 3, Box 3630 • Myton, UT 84052 • 435-646-3721 • FAX 435-646-3031
Corporate Office • 410 Seventeenth Street, Suite 700 • Denver, CO 80202 • 303-893-0102 • FAX 303-893-0103

INLAND PRODUCTION COMPANY
BLACKJACK FEDERAL #12-10-9-17
NW/SW SECTION 10, 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	5850'

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 #12-10-9-17
NW/SW SECTION 10, 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 #12-10-9-17 located in the NW 1/4 SW 1/4 Section 10, 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 – 12.7 miles ± to it's junction with the beginning of the proposed access road; proceed southwesterly along the proposed access road 1,000' ± 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. MOAC Report #03-62, 6/20/03. Paleontological Resource Survey prepared by, Wade E. Miller, 5/8/03. See attached report cover pages, Exhibit "D".

Inland Production Company requests a 60' ROW for the Blackjack Federal #12-10-9-17 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
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, the recontoured surface of the reserve pit, and for final reclamation: (All poundages are in pure live seed)

Gardner Saltbush	*Atriplex gardneri*	4 lbs/acre
Galleta Grass	*Hilaria jamesii*	4 lbs/acre
Kochia Americana		4 lbs/acre

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 #12-10-9-17 NW/SW Section 10, Township 9S, Range 17E: Lease UTU-70821 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.

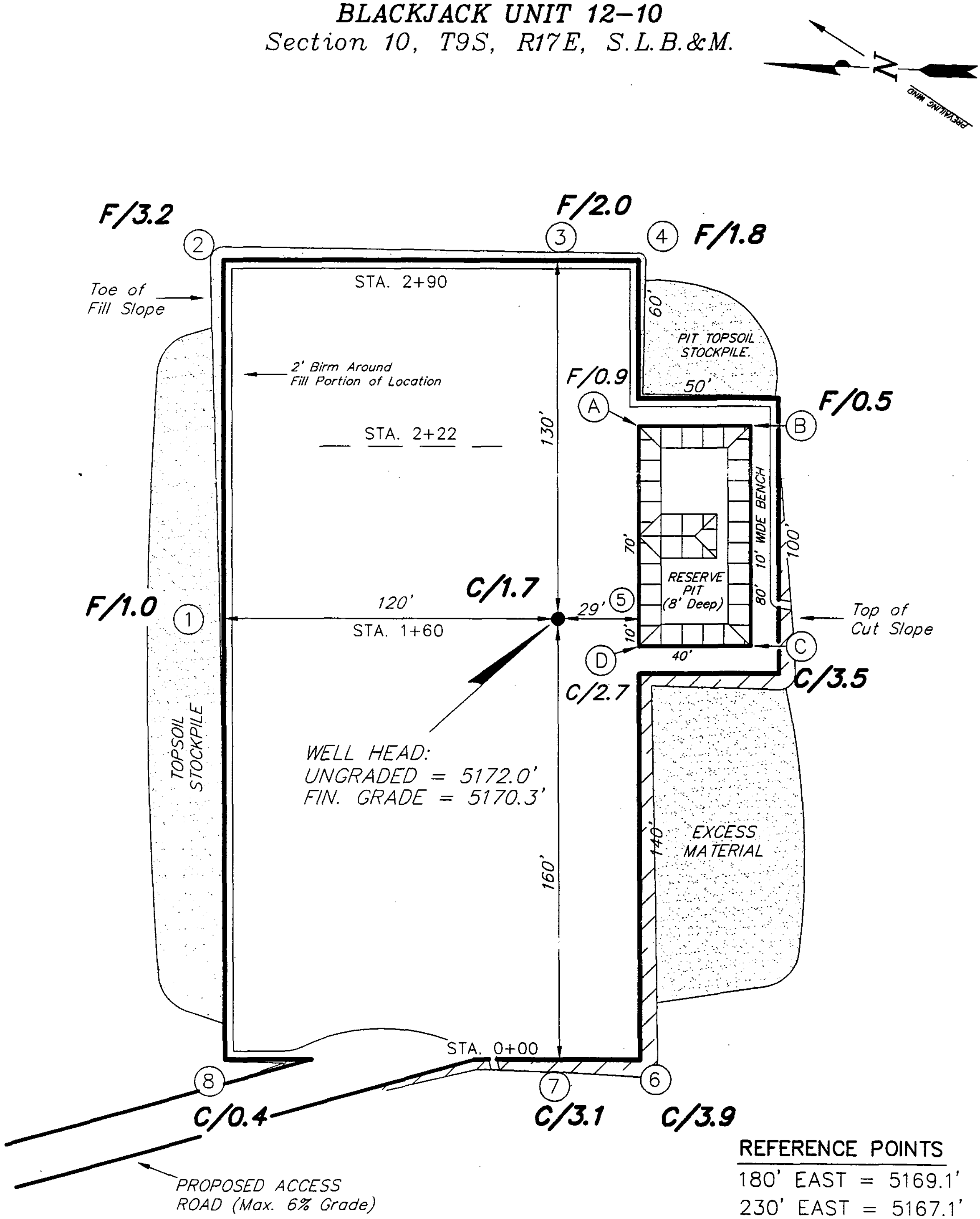
10/2/03
Date

Mandie Crozier
Mandie Crozier
Regulatory Specialist

INLAND PRODUCTION COMPANY

BLACKJACK UNIT 12–10

Section 10, T9S, R17E, S.L.B.&M.



REFERENCE POINTS

180' EAST = 5169.1'
230' EAST = 5167.1'
170' NORTH = 5168.6'
220' NORTH = 5168.1'

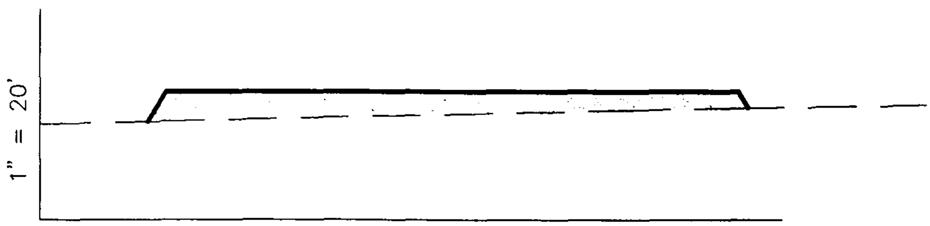
SURVEYED BY:	D.J.S.	SCALE:	1" = 50'
DRAWN BY:	R.V.C.	DATE:	8-21-03

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

INLAND PRODUCTION COMPANY

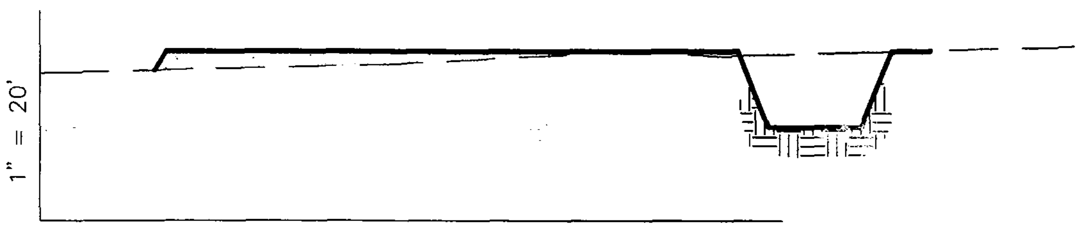
CROSS SECTIONS

BLACKJACK UNIT 12-10



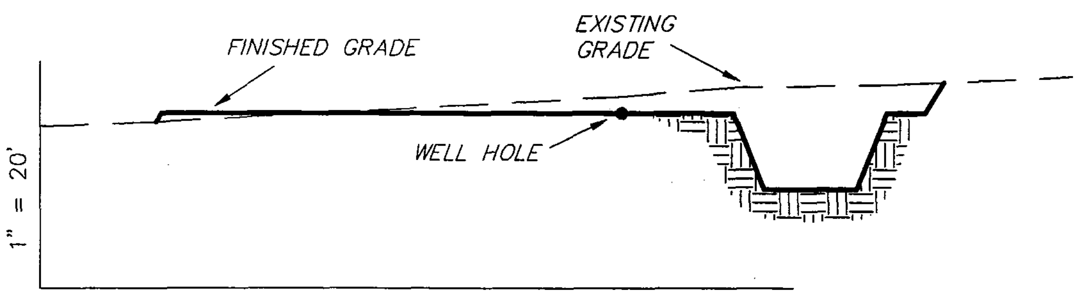
1" = 50'

STA. 2+90



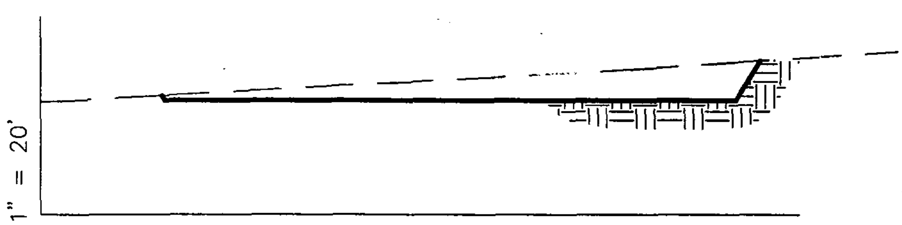
1" = 50'

STA. 2+22



1" = 50'

STA. 1+60



1" = 50'

STA. 0+00

ESTIMATED EARTHWORK QUANTITIES
(Expressed in Cubic Yards)

ITEM	CUT	FILL	6" TOPSOIL	EXCESS
PAD	1,320	1,320	Topsoil is not included in Pad Cut	0
PIT	640	0		640
TOTALS	1,960	1,320	890	640

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

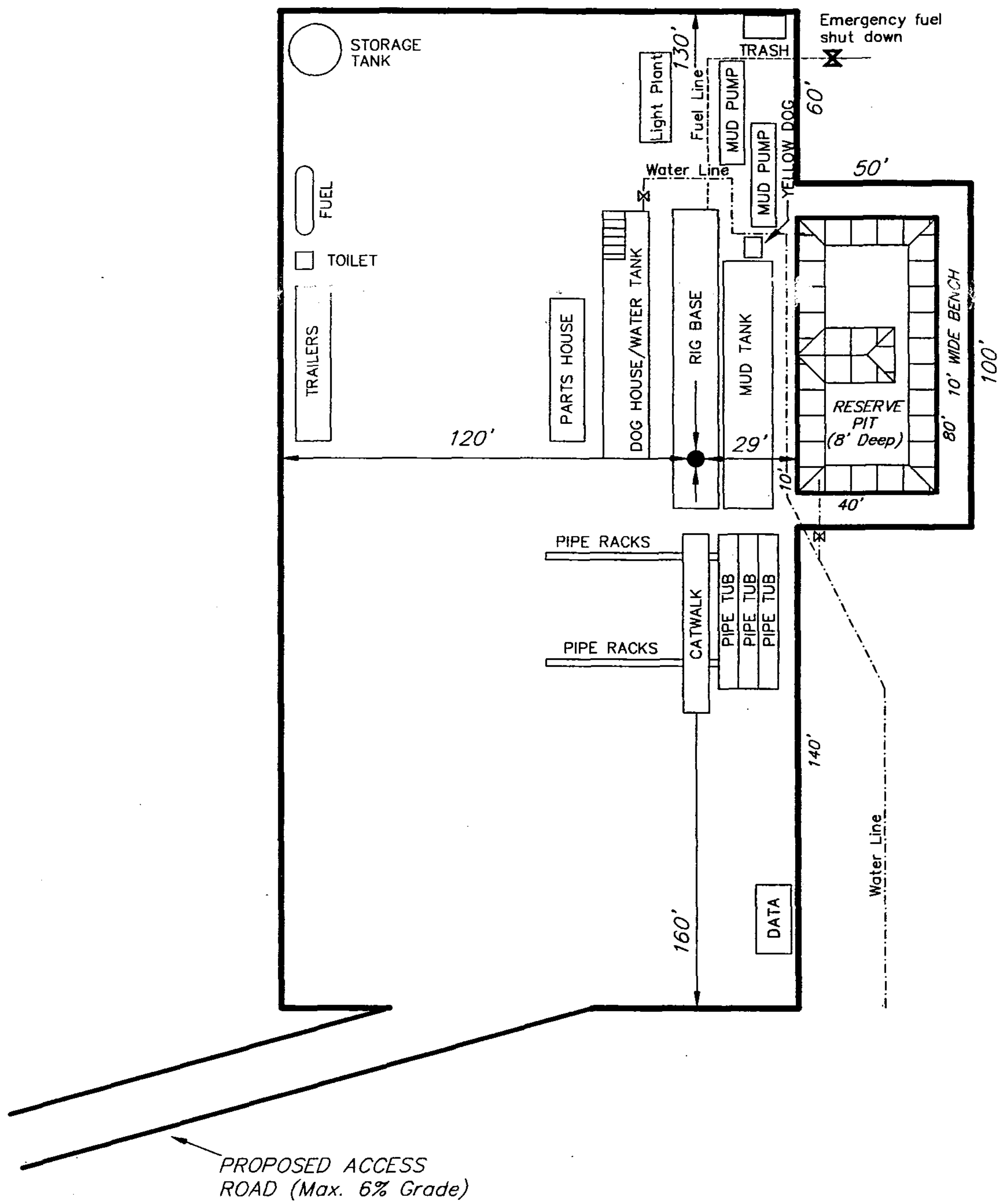
SURVEYED BY:	D.J.S.	SCALE:	1" = 50'
DRAWN BY:	R.V.C.	DATE:	8-21-03

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

INLAND PRODUCTION COMPANY

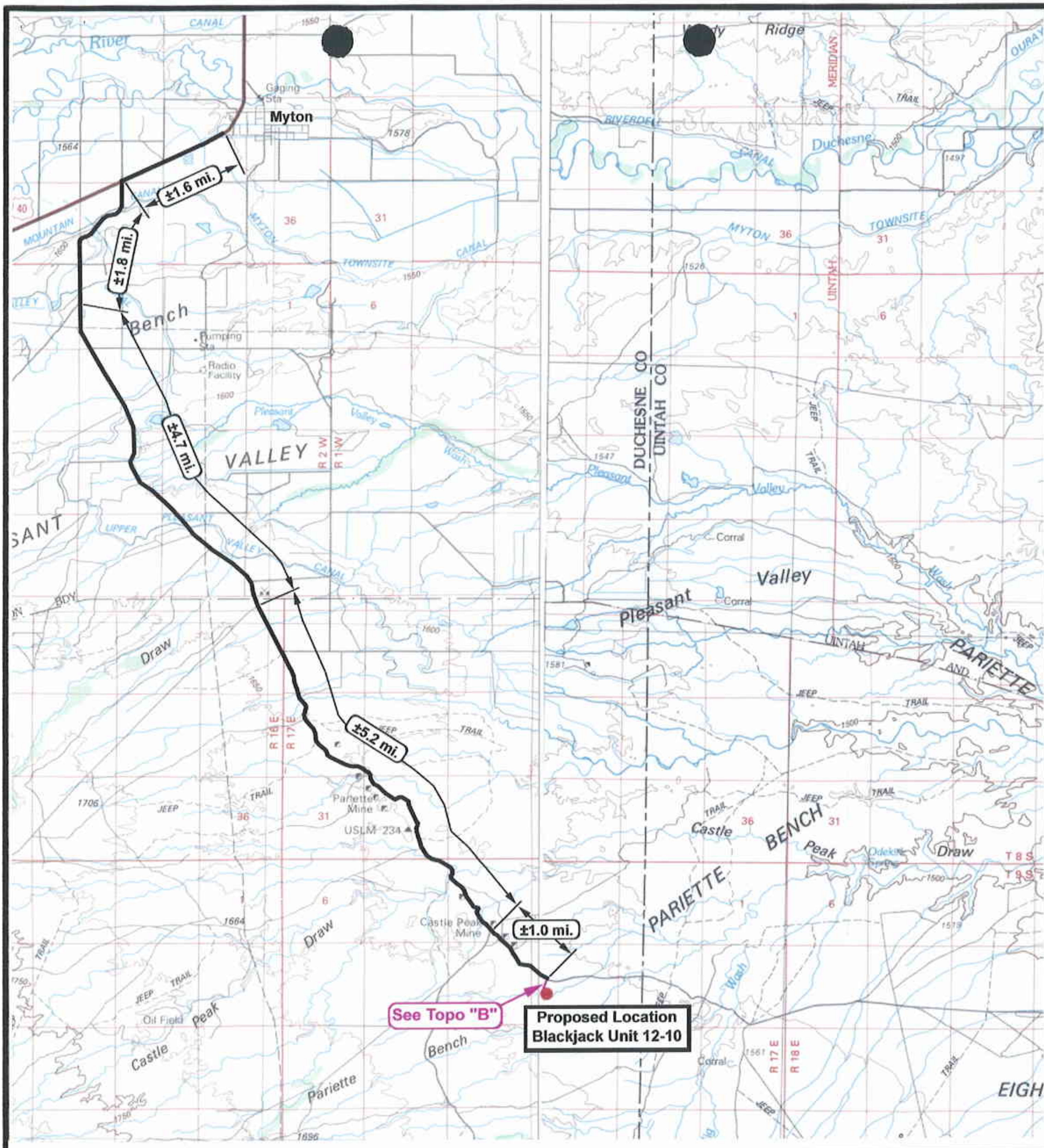
TYPICAL RIG LAYOUT

BLACKJACK UNIT 12–10



SURVEYED BY:	D.J.S.	SCALE:	1" = 50'
DRAWN BY:	R.V.C.	DATE:	8-21-03

Tri State Land Surveying, Inc. (435) 781-2501
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

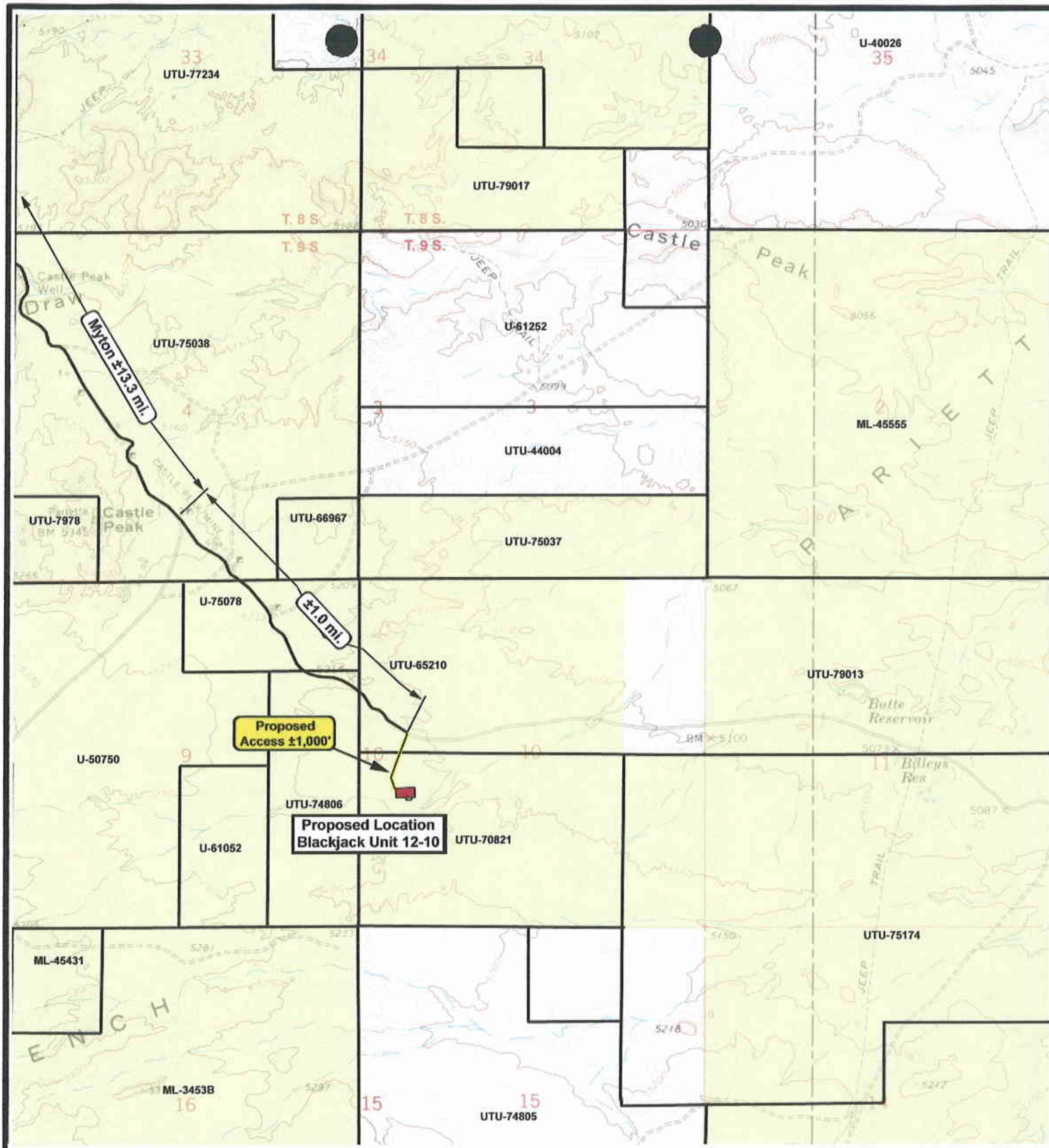
Legend

	Existing Road
	Proposed Access

Blackjack Unit 12-10
SEC. 10, T9S, R17E, S.L.B.&M.

SCALE: 1 = 100,000
DRAWN BY: R.A.B.
DATE: 08-26-2003

TOPOGRAPHIC MAP
"A"



Inland RESOURCES INC.

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

N

Legend

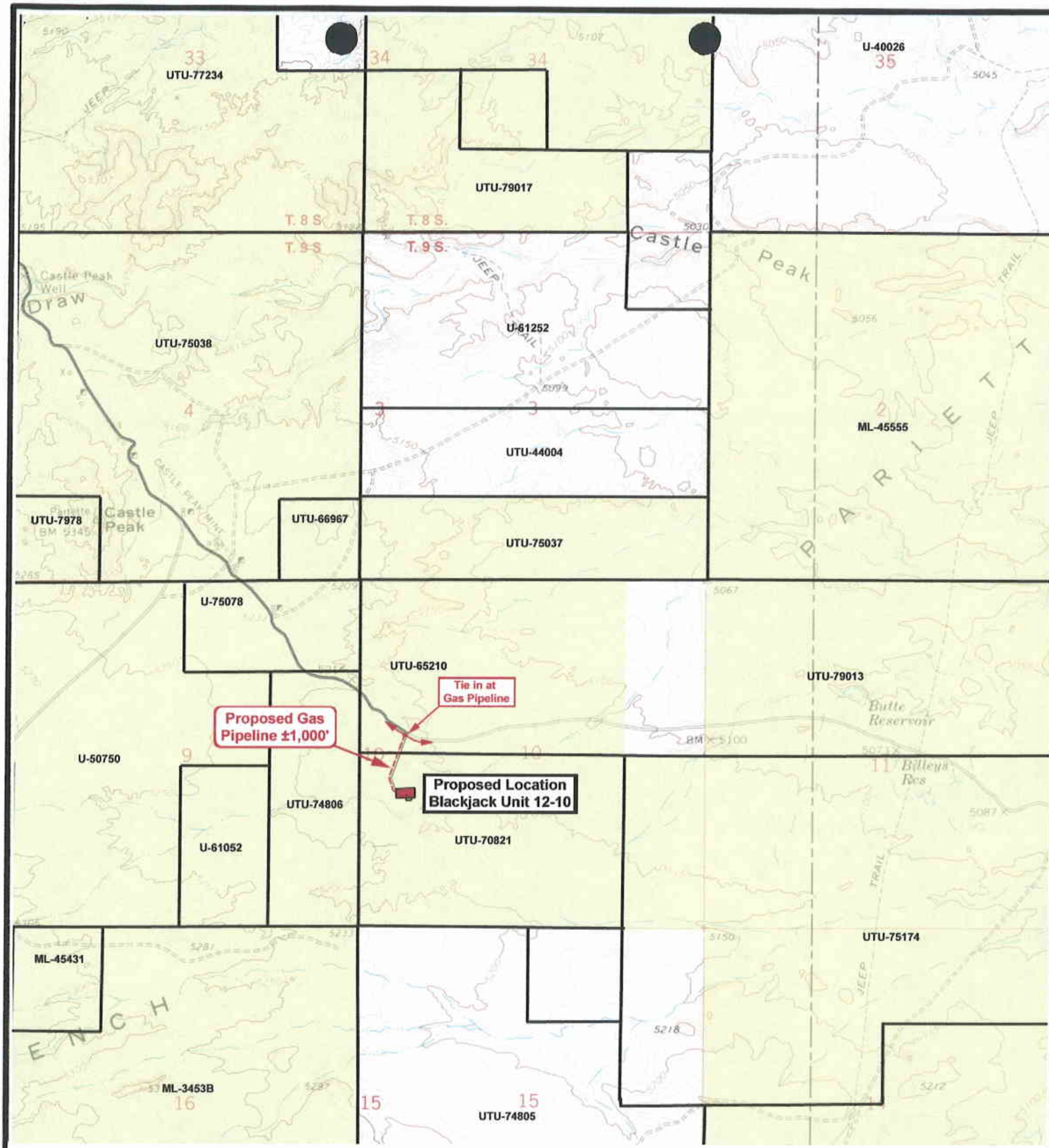
Existing Road

Proposed Access

Blackjack Unit 12-10
SEC. 10, T9S, R17E, S.L.B.&M.

SCALE: 1" = 2,000'
DRAWN BY: R.A.B.
DATE: 08-26-2003

TOPOGRAPHIC MAP
"B"



RESOURCES INC.

Blackjack Unit 12-10
SEC. 10, T9S, R17E, S.L.B.&M.

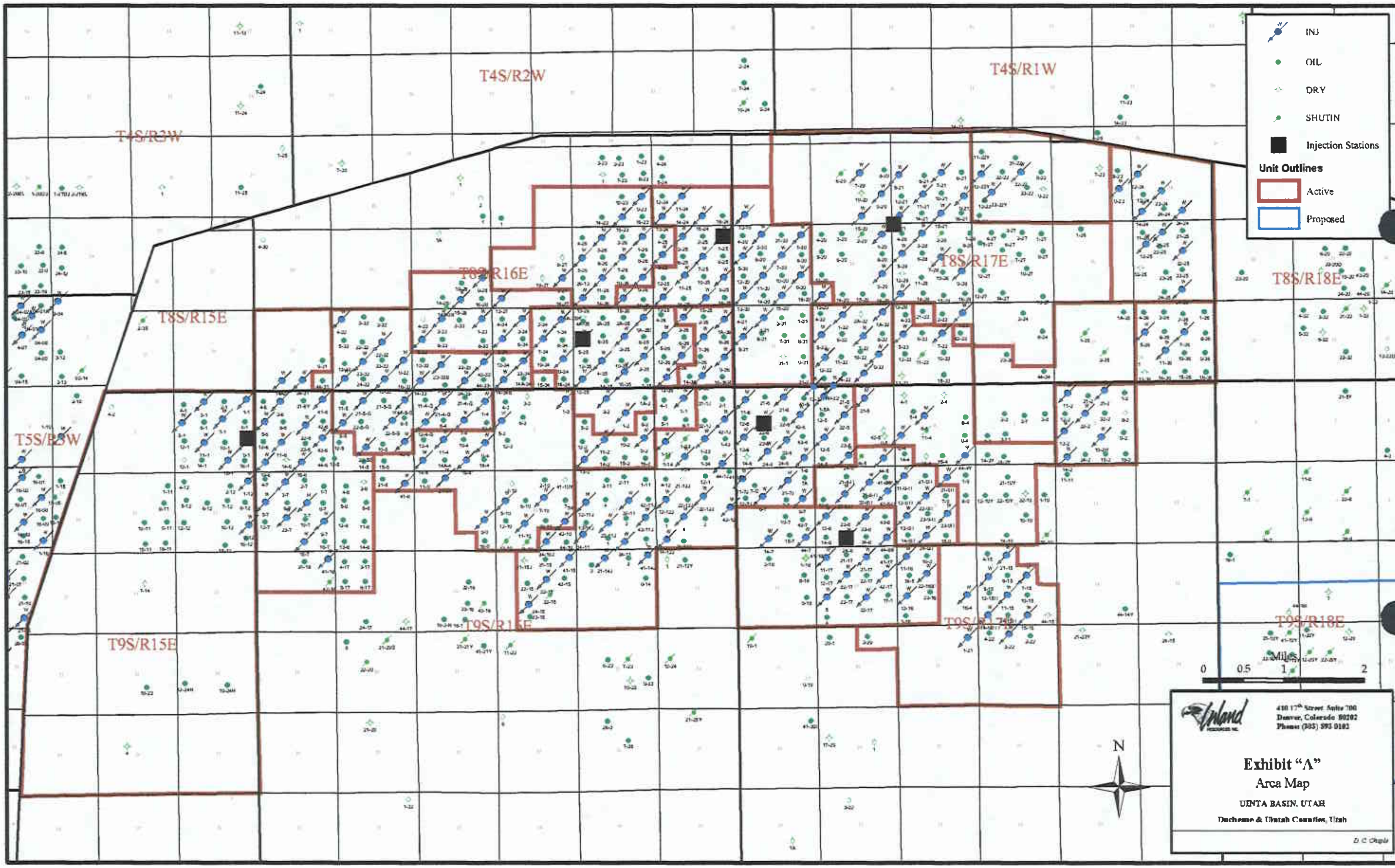
N

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

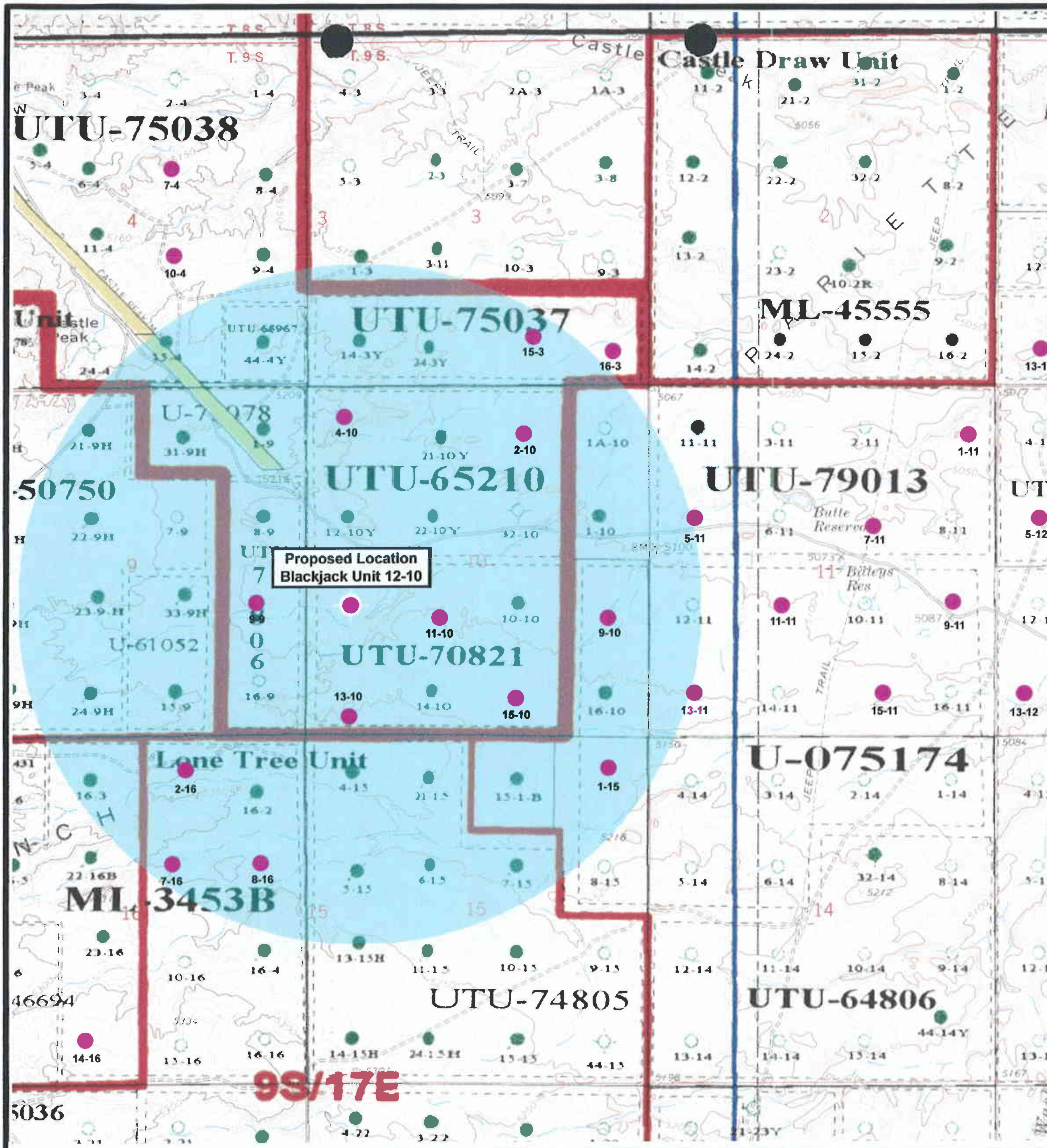
Legend
- Roads
- Existing Gas Line
- Proposed Gas Line

SCALE: 1" = 2,000'
DRAWN BY: R.A.B.
DATE: 08-26-2003

TOPOGRAPHIC MAP
"C"



January 15, 2003



Inland RESOURCES INC.

Blackjack Unit 12-10
SEC. 10, 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: 08-26-2002

Legend

Well Locations
One-Mile Radius

Exhibit "B"

2-M SYSTEM

Blowout Prevention Equipment Systems

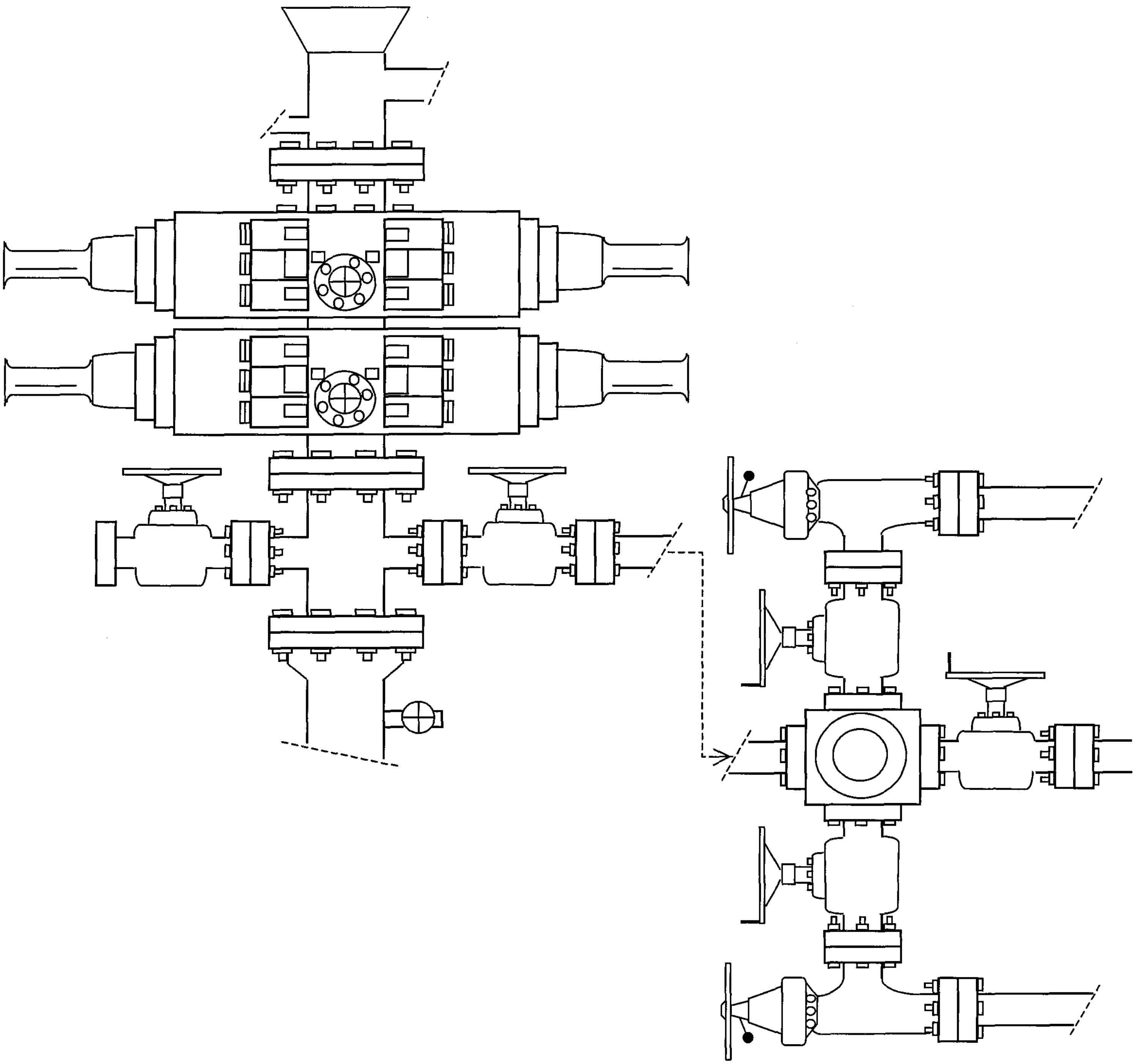


EXHIBIT C

Exhibit "D"
Page 1 of 2

CULTURAL RESOURCE INVENTORY OF INLAND RESOURCES' BLOCK PARCELS IN T 9S, R 18E, SECTION 5 and T9S, R17E, SECTIONS 9 AND 10 DUCHESNE AND UINTAH COUNTIES, UTAH

BY:

Angela Whitfield
and
Mark C. Bond

Prepared For:

Bureau of Land Management
Vernal Field Office

Prepared Under Contract With:

Jon D. Holst & Company
for
Inland Resources
2507 Flintridge Place
Fort Collins, CO 80521

Prepared By:

Montgomery Archaeological Consultants
P.O. Box 147
Moab, Utah 84532

MOAC Report No. 03-62

June 20, 2003

United States Department of Interior (FLPMA)
Permit No. 03-UT-60122

State of Utah Antiquities Project (Survey)
Permit No. U-03-MQ-0390b

INLAND RESOURCES, INC.

PALEONTOLOGICAL FIELD SURVEY OF PROPOSED PRODUCTION DEVELOPMENT AREAS, DUCHESNE AND UINTAH COUNTIES, UTAH

(South ½ Section 6, T 9 S, R 18 E; South ½ Section 1, T 9 S, 17 R E;
all of Sections 11 and 12, the NW, SE & NE quarters of the SW 1/4 Section 10,
the NE1/4 & SE 1/4 of the SE 1/4 Section 9, T 9 S, R 17 E and the SE 1/4, SW 1/4,
NE 1/4 and SE 1/4 of the SE 1/4, Section 33, T 8 S, R 17 E.)

REPORT OF SURVEY

Prepared for:

Inland Resources, Inc.

Prepared by:

Wade E. Miller
Consulting Paleontologist
May 8, 2003

WORKSHEET
APPLICATION FOR PERMIT TO DRILL

APD RECEIVED: 10/03/2003

API NO. ASSIGNED: 43-013-32505

WELL NAME: BLACKJACK FED 12-10-9-17
OPERATOR: INLAND PRODUCTION (N5160)
CONTACT: MANDIE CROZIER

PHONE NUMBER: 435-646-3721

PROPOSED LOCATION:
NWSW 10 090S 170E
SURFACE: 1999 FSL 0730 FWL
BOTTOM: 1999 FSL 0730 FWL
DUCHESNE
MONUMENT BUTTE (105)

INSPECT LOCATN BY: / /

Tech Review	Initials	Date
Engineering		
Geology		
Surface		

LEASE TYPE: 1 - Federal
LEASE NUMBER: UTU-70821
SURFACE OWNER: 1 - Federal
PROPOSED FORMATION: GRRV

LATITUDE: 40.04375
LONGITUDE: 109.99888

RECEIVED AND/OR REVIEWED:

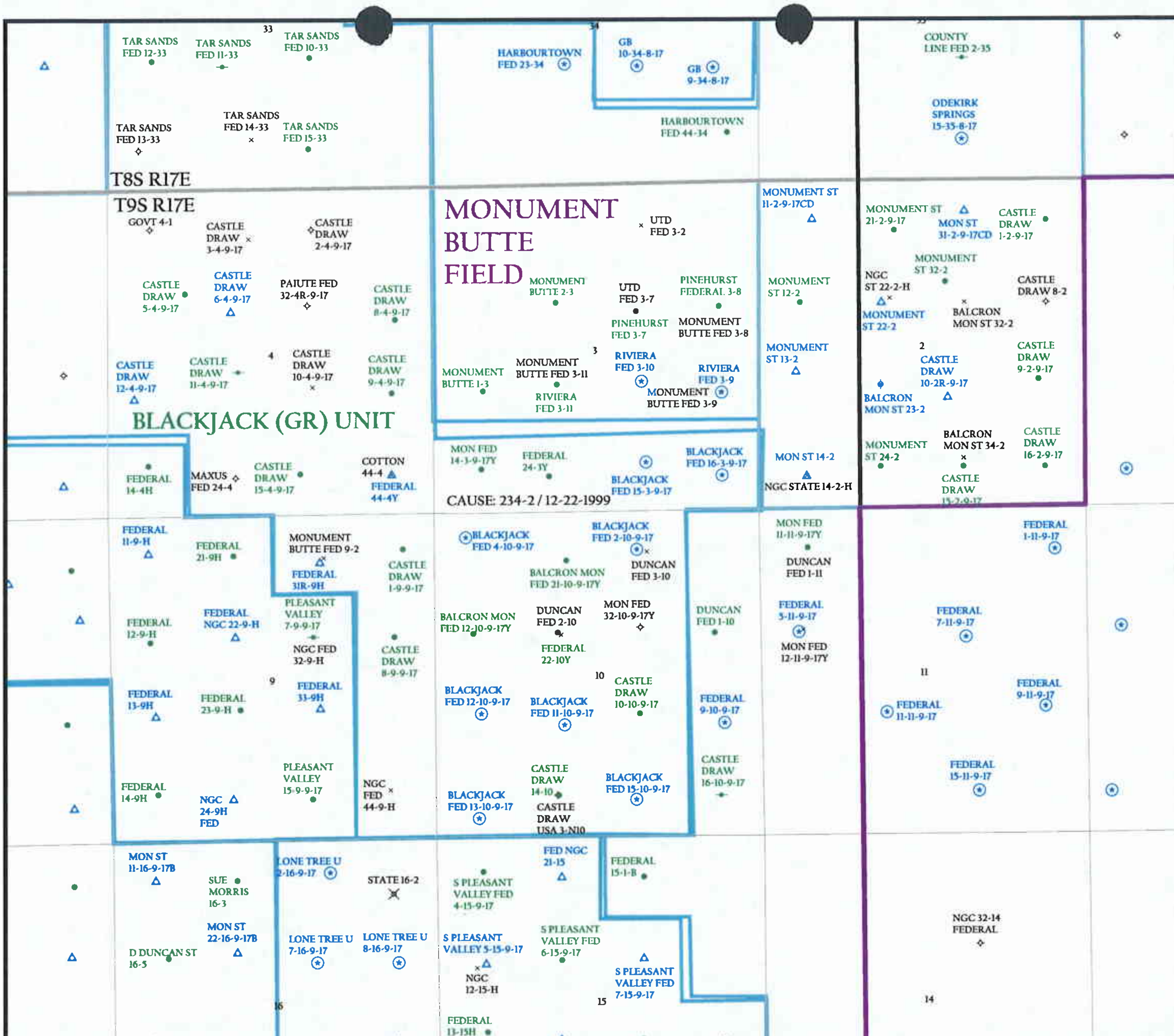
✓ Plat
✓ Bond: Fed[1] Ind[] Sta[] Fee[]
(No. 4488944)
N Potash (Y/N)
N Oil Shale 190-5 (B) or 190-3 or 190-13
✓ Water Permit
(No. MUNICIPAL)
N RDCC Review (Y/N)
(Date:)
NA Fee Surf Agreement (Y/N)

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: 12-22-99
Siting: Suspends General Siting
____ R649-3-11. Directional Drill

COMMENTS: Sop, Seperate file

STIPULATIONS: 1- Federal Approval



OPERATOR: INLAND PRODUCTION CO (N5160)

SEC. 10 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 MASON
DATE: 10-OCTOBER-2003

005

State of Utah

DEPARTMENT OF NATURAL RESOURCES
DIVISION OF OIL, GAS AND MINING

Michael O. Leavitt
Governor
Robert L. Morgan
Executive Director
Lowell P. Braxton
Division Director

1594 West North Temple, Suite 1210
PO Box 145801
Salt Lake City, Utah 84114-5801
(801) 538-5340 telephone
(801) 359-3940 fax
(801) 538-7223 TTY
www.nr.utah.gov

October 14, 2003

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

Re: Blackjack Federal 12-10-9-17 Well, 1999' FSL, 730' FWL, NW SW, Sec. 10, 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 43-013-32505.

Sincerely,

(for) 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 12-10-9-17
API Number: 43-013-32505
Lease: UTU-70821

Location: NW SW **Sec.** 10 **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.

6

006

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-70821

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

7. If Unit or CA Agreement, Name and No.: BlackJack Unit

8. Lease Name and Well No.: BlackJack Federal 12-10-9-17

1a. Type of Work: ☒ DRILL ☐ REENTER

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

2. Name of Operator: Inland Production Company

9. API Well No. 43-013-32505

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/SW 1999' FSL 730' FWL
At proposed prod. zone

OCT - 3 2003

11. Sec., T., R., M., or Blk. and Survey or Area: NW/SW Sec. 10, T9S R17E

14. Distance in miles and direction from nearest town or post office*: Approximatley 14.3 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. 730' f/lse, 1999' f/unit

16. No. of Acres in lease: 240.00

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. 1524'

19. Proposed Depth: 6500'

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

21. Elevations (Show whether DF, KDB, RT, GL, etc.): 5172' GR

22. Approximate date work will start*: 1st 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: 10/2/03

Title: Regulatory Specialist

Approved by *(Signature)*: Edwin I. Forsman | Name *(Printed/Typed)*: EDWIN I. FORSMAN | Date: 4/7/04

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.

NOTICE OF APPROVAL

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
APR 1 5 2004
DIV. OF OIL, GAS & MINING

CONDITIONS OF APPROVAL ATTACHED

CONDITIONS OF APPROVAL
APPLICATION FOR PERMIT TO DRILL

Company/Operator: Inland Production Company

Well Name & Number: BLACKJACK FEDERAL 12-10-9-17

API Number: 43-013-32505

Lease Number: UTU – 70821

Location: NWSW Sec. 10 TWN: 09S RNG: 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 FOR NOTICE TO DRILL

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.

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

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.

A. DRILLING PROGRAM

1. Casing Program and Auxiliary Equipment

As a minimum, the usable water and oil shale resources shall be isolated and/or protected by having a cement top for the production casing at least 200 ft. above the top of the Green River Formation, identified at ±2,133 ft.

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

-No construction or drilling shall be allowed during the burrowing owl nesting season (April 1 to Aug. 15), without first consulting the BLM biologist. If no nesting owls are found, drilling will be allowed.

-Mountain Plover surveys would have to be conducted in accordance with the U.S. Fish and Wildlife Service Mountain Plover Survey Guidelines.

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

-A BLM approved paleontologist shall monitor all areas of bedrock exposure during 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 12-10-9-17

Api No: 43-013-32505 Lease Type: FEDERAL

Section 10 Township 09S Range 17E County DUCHESNE

Drilling Contractor ROSS DRILLING RIG # 15

SPUDDED:

Date 07/17/04

Time 2:30 PM

How DRY

Drilling will commence:

Reported by RAY HERRERA

Telephone # 1-435-823-1990

Date 07/19/2004 **Signed** CHD

008

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

OPERATOR: INLAND PRODUCTION COMPANY
ADDRESS: RT. 3 BOX 3630
MYTON, UT 84052

OPERATOR ACCT. NO. N5160

ACTION CODE	CURRENT ENTITY NO.	NEW ENTITY NO.	API NUMBER	WELL NAME	WELL LOCATION QQ	SC	TP	RG	COUNTY	SPUD DATE	EFFECTIVE DATE
B	99999	12704	43-013-32505	BlackJack Federal 12-10-9-17	NW/SW	10	9S	17E	Duchesne	July 17, 2004	7/21/04

K

WELL 1 COMMENTS: GRRV

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

WELL 2 COMMENTS:

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

WELL 3 COMMENTS:

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

WELL 4 COMMENTS:

ACTION CODE	CURRENT ENTITY NO.	NEW ENTITY NO.	API NUMBER	WELL NAME	WELL LOCATION 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.

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

Kebbie S Jones
Signature Kebbie S. Jones

Production Clerk
Title

July 21, 2004
Date

FORM 3160-5
(June 1990)

.009

UNITED STATES
DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

FORM APPROVED
Budget Bureau No. 1004-0135
Expires: March 31, 1993

SUNDRY NOTICES AND REPORTS ON WELLS

Do not use this form for proposals to drill or to deepen or reentry a different reservoir.
Use "APPLICATION FOR PERMIT -" for such proposals

SUBMIT IN TRIPLICATE

5. Lease Designation and Serial No.
UTU-70821

6. If Indian, Allottee or Tribe Name
NA

7. If Unit or CA, Agreement Designation
BLACKJACK

1. Type of Well
[X] Oil Well [ ] Gas Well [ ] Other

8. Well Name and No.
BLACKJACK FEDERAL 12-10-9-17

9. API Well No.
43-013-~~32402~~ 32505

2. Name of Operator
INLAND PRODUCTION COMPANY

10. Field and Pool, or Exploratory Area
MONUMENT BUTTE

3. Address and Telephone No.
Rt. 3 Box 3630, Myton Utah, 84052 435-646-3721

11. County or Parish, State
DUCHESNE COUNTY, UT

4. Location of Well (Footage, Sec., T., R., m., or Survey Description)
1999 FSL 730 FWL NW/SW Section 10, T9S R17E

12. CHECK APPROPRIATE BOX(s) TO INDICATE NATURE OF NOTICE, REPORT, OR OTHER DATA

TYPE OF SUBMISSION	TYPE OF ACTION	
[ ] Notice of Intent	[ ] Abandonment	[ ] Change of Plans
[X] Subsequent Report	[ ] Recompletion	[ ] New Construction
[ ] Final Abandonment Notice	[ ] Plugging Back	[ ] Non-Routine Fracturing
	[ ] Casing Repair	[ ] Water Shut-Off
	[ ] Altering Casing	[ ] Conversion to Injection
	[x] Other **Weekly Status Report**	[ ] Dispose Water

(Note: Report results of multiple completion on Well Completion or Recompletion Report and Log form.)

13. Describe Proposed or Completed Operations (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work. If well is directionally drilled, give subsurface locations and measured and true vertical depths for all markers and zones pertinent to this work.)*

On 07/22/04. MIRU Eagle rig #2. Set equipment. Pressure test Bop's, Kelly, & TIW to 2,000 psi. Test 85/8" csgn to 1,500 psi. Vernal BLM office was notified of test. PU BHA and tag cement @ 265'. Drill out cement & shoe. Continue to drill a 77/8" hole with fresh water to a depth of 5785". Lay down drill string, BHA. Open hole log from TD to surface. PU & MU guide shoe, 1 jt 51/2" J-55 15.5 # csgn. Float collar, & 133 Jt's 51/2" J-55 15.5# csgn. Set @ 5768'/ KB. Cement with 325 sks Prem Lite ll w/ 3% KCL, 10% Gel, 3#"s sk CSE, 2#'s sk Kolseal, 5% Sms, 1/4# sks Celloflake. Mixed @ 11.0 ppg, >3.43 yld. Followed by 425 sks 50/50 Poz w/ 3% KCL, 2% Gel, .05% Static free, 1/4# sk Celloflake .3%SM. Mixed @ 14.4 ppg, > 1.24 yld. Good returns with 10 bbls cement return to pit. Nipple down BOP's. Drop slips @ 85,000 # 's tension. Clean pit's & release rig @ 4:30 am on 07-29-04.

14. I hereby certify that the foregoing is true and correct
Signed Ray Herrera Title **Drilling Foreman** Date **July 30 2004**
Ray Herrera

CC: UTAH DOGM

(This space for Federal or State office use)
Approved by ______ Title ______ Date ______
Conditions of approval, if any:
CC: Utah DOGM

RECEIVED
AUG 03 2004
DIV. OF OIL, GAS & MINING

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

INLAND PRODUCTION COMPANY - CASING & CEMENT REPORT

5 1/2" CASING SET AT 5768.23

Flt cllr @ 5715.89

LAST CASING	8 5/8" SET AT 309.21'	OPERATOR	Inland Production Company
DATUM	12'/ KB	WELL	Black Jack 12-10-9-17
DATUM TO CUT OFF CASING	12	FIELD/PROSPECT	Monument Butte
DATUM TO BRADENHEAD FLANGE		CONTRACTOR & RIG #	Eagle # 2
TD DRILLER	5785' LOGGER		
HOLE SIZE	7 7/8"		

LOG OF CASING STRING:

PIECES	OD	ITEM - MAKE - DESCRIPTION	WT / FT	GRD	THREAD	CONDT	LENGTH
		Landing Jt					14
		5.10' @ 4007'					
133	5 1/2"	IPS LT & C casing	15.5#	J-55	8rd	A	5715.35
		Float collar					0.6
1	5 1/2"	Maverick LT&C csg	15.5#	J-55	8rd	A	39.63
		GUIDE shoe			8rd	A	0.65

CASING INVENTORY BAL.	FEET	JTS		
TOTAL LENGTH OF STRING	5770.23	134	TOTAL LENGTH OF STRING	5770.23
LESS NON CSG. ITEMS	15.25		LESS CUT OFF PIECE	14
PLUS FULL JTS. LEFT OUT	170.72	4	PLUS DATUM TO T/CUT OFF CSG	12
TOTAL	5925.70	139	CASING SET DEPTH	5768.23
TOTAL CSG. DEL. (W/O THRDS)	5925.7	139	} COMPARE	

TIMING	1ST STAGE	2nd STAGE		
BEGIN RUN CSG.	4:30pm	7/28/2004	GOOD CIRC THRU JOB	yes
CSG. IN HOLE	8:30pm	7/28/2004	Bbls CMT CIRC TO SURFACE	10 bbls
BEGIN CIRC	8:35 PM		RECIPROCATED PIPE I N/A	THRUSTROKE
BEGIN PUMP CMT	8:56pm		DID BACK PRES. VALVE HOLD ?	Yes
BEGIN DSPL. CMT	10:55pm	7/28/2004	BUMPED PLUG TO	2100 PSI
PLUG DOWN	11:18 PM	7/28/2004		

CEMENT USED		CEMENT COMPANY- B. J.
STAGE	# SX	CEMENT TYPE & ADDITIVES
1	325	Premlite II w/ 10% gel + 3 % KCL, 3#'s /sk CSE + 2# sk/kolseal + 1/2#'s/sk Cello Flake
		mixed @ 11.0 ppg W / 3.43 cf/sk yield
2	425	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 Ray Herrera DATE 7/29/2004

RECEIVED
AUG 03 2004
DIV. OF OIL, GAS & MINING

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

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

1. Type of Well
[X] Oil Well [ ] Gas Well [ ] Other

2. Name of Operator
Inland 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)*
1999 FSL 730 FWL
NW/SW Section 10 T9S R17E

5. Lease Serial No.
UTU70821

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 12-10-9-17

9. API Well No.
4301332505

10. Field and Pool, or Exploratory Area
Monument Butte

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
[X] Subsequent Report	[ ] Alter Casing	[ ] Fracture Treat	[ ] Reclamation	[ ] Well Integrity
[ ] Final Abandonment Notice	[ ] Casing Repair	[ ] New Construction	[ ] Recomplete	[X] 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 08/06/04 - 08/16/04
Subject well had completion procedures initiated in the Green River formation on 08/06/04 without the use of a service rig over the well. A cement bond log was run and a total of four Green River intervals were perforated and hydraulically fracture treated w/ 20/40 mesh sand. Perf intervals were #1 (5647-5654'), (5616-5624'), (5530-5540') (ALL 4 JSPF); #2 (5365-5370'), (5358-5362') (All 4 JSPF); #3 (4986-4993'), (4927-4935') (ALL 4 JSPF); #4 (4677-4686') (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 08/14/04. Bridge plugs were drilled out. Well was cleaned out to PBTD @ 5726'. Zones were swab tested for sand cleanup. A BHA & production tbg string were run in and anchored in well. End of tubing string @ 5641'. A new 1 1/2" bore rod pump was run in well on sucker rods. Well was placed on production via rod pump on 08/16/04.

RECEIVED
AUG 19 2004
DIV. OF OIL, GAS & MINING

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

Title
Production Clerk

Signature
Marnie Bryson

Date
8/18/2004

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

(Instructions on reverse)

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

FILED
In the Office of the
Secretary of State of Texas

SEP 02 2004

Corporations Section

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

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

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 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
020252
020252A
020254
020255
020309D
022684A
027345
034217A
035521
035521A
038797
058149
063597A
075174
096547
096550

10760
11385
13905
15392
15855
16535
16539
16544
17036
17424
18048
18399
19267
26026A
30096
30103
31260
33992
34173
34346
36442
36846
38411
38428
38429
38431
39713
39714
40026
40652
40894
41377
44210
44426
44430
45431
47171
49092
49430
49950
50376
50385
50376
50750
51081
52013
52018
58546
61052
62848
63073B
63073D
63073E
63073O
64917
64379
64380
64381
64805
64806
64917
65207
65210
65635
65967
65969
65970
66184
66185
66191
67168
67170
67208
67549
67586
67845
68105
68548
68618
69060
69061
69744
70821
72103
72104
72105
72106
72107
72108
73086
73087
73807
73088
73089
73520A
74108
74805
74806
74807
74808
74389
74390
74391
74392
74393
74398
74399
74400
74404
74405
74406
74411
74805
74806
74826
74827
74835
74868
74869
74870
74872
74970
75036
75037
75038
75039
75075
75078
75089
75090
75234
75238
76239
76240
76241
76560
76561
76787
76808
76813
76954
76956
77233
77234
77235
77337
77338
77339
77357
77359
77365
77369
77370
77546
77553
77554
78022
79013
79014
79015
79016
79017
79831
79832
79833
79831
79834
80450
80915
81000

63073X
63098A
68528A
72086A
72613A
73520X
74477X
75023X
76189X
76331X
76788X
77098X
77107X
77236X
77376X
78560X
79485X
79641X
80207X
81307X

FORM 3160-4
(July 1992)

011

SUBMIT IN D[illegible]CATE*
(See other instructions ons reverse side)

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

UNITED STATES
DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

WELL COMPLETION OR RECOMPLETION REPORT AND LOG*

5. LEASE DESIGNATION AND SERIAL NO.: UTU-70821

6. IF INDIAN, ALLOTTEE OR TRIBE NAME: NA

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

7. UNIT AGREEMENT NAME: Blackjack Unit

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

8. FARM OR LEASE NAME, WELL NO.: Blackjack Federal 12-10-9-17

2. NAME OF OPERATOR: INLAND RESOURCES INC.

9. WELL NO.: 43-013-32505

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

10. FIELD AND POOL OR WILDCAT: Monument Butte

4. LOCATION OF WELL (Report locations clearly and in accordance with any State requirements.*)
At Surface: 1999' FSL & 730' FWL (NW SW) Sec. 10, T9S, R17E
At top prod. Interval reported below
At total depth

11. SEC., T., R., M., OR BLOCK AND SURVEY OR AREA: Sec. 10, T9S, R17E

14. API NO.: 43-013-32505 | DATE ISSUED: 10/14/2003

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
7/14/2004	7/21/2004	8/16/2004	5172' GL 5184' 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
5785'	5726'		------>	X	

24. PRODUCING INTERVAL(S), OF THIS COMPLETION--TOP, BOTTOM, NAME (MD AND TVD)*: Green River 4677'-5654'

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#	309'	12-1/4"	To surface with 150 sx Class "G" cmt	
5-1/2" - J-55	15.5#	5768'	7-7/8"	325 sx Premlite II and 425 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 @ 5641'	TA @ 5508'

31. PERFORATION RECORD (Interval, size and number)

INTERVAL	SIZE	SPF/NUMBER
(CP4,5) 5530-40', 5616-24', 5647-54'	.41"	4/100
(CP1) 5358-62', 5365-70'	.41"	4/36
(A1,3) 4927-35', 4986-93'	.41"	4/60
(C-sd) 4677-86'	.41"	4/36

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

DEPTH INTERVAL (MD)	AMOUNT AND KIND OF MATERIAL USED
5530'-5654'	Frac w/ 39,909# 20/40 sand in 382 bbls fluid.
5358'-5370'	Frac w/ 37,686# 20/40 sand in 357 bbls fluid.
4927'-4993'	Frac w/ 33,275# 20/40 sand in 335 bbls fluid.
4677-4686'	Frac w/ 15,212# 20/40 sand in 220 bbls fluid.

33.* PRODUCTION

DATE FIRST PRODUCTION	PRODUCTION METHOD (Flowing, gas lift, pumping--size and type of pump)	WELL STATUS (Producing or shut-in)
8/16/2004		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			----->	22	15	2	682

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

RECEIVED
SEP 23 2004
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 Brian Harris TITLE Engineering Technician DATE 9/17/2004

Brian Harris

BDH

*(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 Federal 12-10-9-17**

38. GEOLOGIC MARKERS

NAME	TOP	
	MEAS. DEPTH	TRUE VERT. DEPTH
Garden Gulch Mkr	3515'	
Garden Gulch 1	3708'	
Garden Gulch 2	3821'	
Point 3 Mkr	4087'	
X Mkr	4324'	
Y-Mkr	4359'	
Douglas Creek Mkr	4486'	
BiCarbonate Mkr	4725'	
B Limestone Mkr	4847'	
Castle Peak	5302'	
Basal Carbonate	5723'	
Total Depth (LOGGERS	5785'	

·Inland Resources Inc.

September 17, 2004

State of Utah, Division of Oil, Gas and Mining
Attn: Ms. Carol Daniels
P.O. Box 145801
Salt Lake City, Utah 84114-5801

Attn: Ms. Carol Daniels

Ashley Federal 14-2-9-15 (43-013-32578)
Duchesne County, Utah

Sandwash Federal 10-31T-8-17 (43-013-32449)
Duchesne County, Utah

Blackjack Federal 12-10-9-17 (43-013-32505)
Duchesne County, Utah

Dear Ms. Carol Daniels

Enclosed is a Well Completion or Recompletion Report and Log form (Form 3160-4). We are no longer sending Log copies since Pat Grissom of Phoenix Surveys is already doing so.

If you should have any questions, please contact me at (303) 382-4449.

Sincerely,

Brian Harris

Brian Harris
Engineering Tech

Enclosures

cc: Bureau of Land Management
Vernal District Office, Division of Minerals
Attn: Edwin I. Forsman
170 South 500 East
Vernal, Utah 84078

Well File – Denver
Well File – Roosevelt
Patsy Barreau/Denver
Bob Jewett/Denver
Matt Richmond/Roosevelt

RECEIVED
SEP 23 2004
DIV. OF OIL, GAS & MINING

Alamo Plaza Building
1401 Seventeenth Street, Suite 1000
Denver, CO 80202
303-893-0102 • Fax: 303-893-0103

Division of Oil, Gas and Mining

ROUTING
1. GLH
2. CDW
3. FILE

OPERATOR CHANGE WORKSHEET

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): 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 9-33-8-17	33	080S	170E	4301332515	12704	Federal	OW	P	K
BLACKJACK FED 16-3-9-17	03	090S	170E	4301332500	12704	Federal	OW	P	K
BLACKJACK FED 15-3-9-17	03	090S	170E	4301332501	12704	Federal	OW	P	K
CASTLE DRAW 5-4-9-17	04	090S	170E	4301332074	12704	Federal	OW	P	
CASTLE DRAW 6-4-9-17	04	090S	170E	4301332075	12704	Federal	WI	A	
CASTLE DRAW 8-4-9-17	04	090S	170E	4301332077	12704	Federal	OW	S	
CASTLE DRAW 9-4-9-17	04	090S	170E	4301332079	12704	Federal	OW	P	
CASTLE DRAW 11-4-9-17	04	090S	170E	4301332081	12704	Federal	OW	S	
CASTLE DRAW 12-4-9-17	04	090S	170E	4301332082	12704	Federal	WI	A	
CASTLE DRAW 15-4-9-17	04	090S	170E	4301332083	12704	Federal	OW	P	
BLACKJACK FED 10-4-9-17	04	090S	170E	4301332509	12704	Federal	OW	P	K
CASTLE DRAW 1-9-9-17	09	090S	170E	4301332071	12704	Federal	OW	P	
CASTLE DRAW 8-9-9-17	09	090S	170E	4301332078	12704	Federal	WI	A	
BLACKJACK FED 16-9-9-17	09	090S	170E	4301332516	12704	Federal	OW	P	K
BLACKJACK FED 15-10-9-17	10	090S	170E	4301332503	12704	Federal	OW	OPS	K
BLACKJACK FED 13-10-9-17	10	090S	170E	4301332504	12704	Federal	OW	P	K
BLACKJACK FED 12-10-9-17	10	090S	170E	4301332505	12704	Federal	OW	P	K
BLACKJACK FED 11-10-9-17	10	090S	170E	4301332506	12704	Federal	OW	P	K
BLACKJACK FED 4-10-9-17	10	090S	170E	4301332507	12704	Federal	OW	P	K
BLACKJACK FED 2-10-9-17	10	090S	170E	4301332508	12704	Federal	OW	P	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**

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

DEC 30 2005

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

43.013.32505
9S 17E 10

Re: Underground Injection Control Program
Permit for the Blackjack Federal 12-10-9-17
Duchesne County, UT
EPA Permit No. UT20994-06735

Dear Mr. Gerbig:

Enclosed is your copy of the FINAL Underground Injection Control (UIC) Permit for the proposed Blackjack Federal 12-10-9-17 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 29 2005. 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
JAN 06 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,

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 7520-14 Plugging Plan
Groundwater Section Guidance 34
Groundwater Section Guidance 35
Groundwater Section Guidance 37
Groundwater Section Guidance 39

cc: w/ encl:

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

Lynn Becker
Director
Energy & Minerals Department
Ute Indian Tribe

S. Elaine Willie
Environmental Coordinator
Ute Indian Tribe

Michael Guinn
Vice President
Newfield Production Company
Myton, Utah

Gilbert Hunt
Technical Services Manager
State of Utah - Natural Resources

Matt Baker
Petroleum Engineer
Bureau of Land Management
Vernal District

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION VIII
999 18th STREET - SUITE 300
DENVER, COLORADO 80202-2466

SUBJECT: **GROUND WATER SECTION GUIDANCE NO. 34**
Cement bond logging techniques and interpretation

FROM: Tom Pike, Chief
UIC Direct Implementation Section

TO: All Section Staff
Montana Operations Office

These procedures are to be followed when running and interpreting cement bond logs for injection and production (area of review) wells.

PART I - PREPARE THE WELL

Allow cement to cure for a sufficient time to develop full compressive strength. A safe bet is to let the cement cure for 72 hours. If you run the bond log before the cement achieves its maximum compressive strength, the log may show poor bonding. Check cement handbooks for curing times.

Circulate the hole with a fluid (either water or mud) of uniform consistency. Travel times are influenced by the type of fluid in the hole. If the fluid changes between two points, the travel times may "drift," causing difficulty in interpretation and quality control.

Be prepared to run the cement bond log under pressure to reduce the effects of micro-annulus. Micro-annulus may be caused by several reasons, but the existence of a micro-annulus does not necessarily destroy the cement's ability to form a hydraulic seal. If the log shows poor bonding, rerun the log with the slightly more pressure on the casing as was present when the cement cured. This will cause the casing to expand against the cement and close the micro-annulus.

PART II - PARAMETERS TO LOG

Amplitude (mV) - This curve shows how much acoustic signal reaches a receiver and is an important indicator of cement bond. Record the amplitude on the 3 foot spaced receiver.

Travel time (µs) - This curve shows the amount of time it takes an acoustic signal to travel between the source and a receiver. For free pipe of a given size and weight, the travel time between points is very predictable, although variable among different company's tools. Service companies should be able to provide accurate estimates of travel times for free pipe of a given size and weight. Travel time is required as a quality control measurement. Record the travel time on the 3 foot spaced receiver.

Variable density (VDL) - Pipe signals, formation signals, and fluid signals are usually easy to recognize on the VDL. If these signals can be identified, a practical determination for the presence or absence of cement can be made. VDL is logged on the 5 foot spaced receiver.

Casing collar locator (CCL) - Used to correlate the bond log with cased hole logs and to match casing collars with the collars that show up on the VDL portion of the display.

Gamma ray - Used to correlate the bond log with other logs.

PART III - LOGGING TECHNIQUE

Calibrate the tool in free pipe at the shop, prior to, and following the log run. Include calibration data with log.

Run receivers spaced 3 feet and 5 feet from transmitter.

Run at least 3 bow-type or rigid aluminum centralizers in vertical holes, 6 centralizers in directional holes. A CCL is not an adequate centralizer.

Complete log header with casing/cement data, tool/panel data, gate settings and tool sketch showing centralizers.

Set the amplitude gate so that skipping does not occur at amplitudes greater than 5 mV.

Record amplitude with fixed gate and note position on log.

Record amplified amplitude on a 5X scale for low amplitudes.

Record amplitude and travel time on the 3 foot receiver.

Record travel time on a 100 µs scale (150 - 250, 200 - 300).

Logging speed should be approximately 30 ft/min.

Log repeat sections.

PART IV - QUALITY CONTROL

Compare the tool calibration data to see if the tool "drifts" during logging. Differences in the calibration data may require you to re-log the well to obtain reliable data.

Compare repeat sections to see if logging results are repeatable.

Check the logged free pipe travel times with the service company charts for the specific tool and casing size used. Since the travel times depend on such factors as casing weight, type of fluid in the hole, etc., these charts should be used only as guidelines. When you are confident of the free-pipe travel times as seen on the log, use them. When interpreting the log, a decrease in travel time (faster times) with simultaneous reduction of amplitude may show a de-centered tool. A 4 to 5 micro-second (µs) decrease in travel time corresponds to about a 35% loss of amplitude. A decrease in travel time more than 4 to 5 µs is unacceptable.

PART V - LOG INTERPRETATION

Do not rely on the service company charts for amplitudes corresponding to a good bond. These amplitudes depend on many factors: type of cement used, fluid in the hole, etc.

To estimate bond index, choose intervals on the log that correspond to 0% bond and 100% bond. Read the amplitude corresponding to 100% bond from the best-bonded interval on the log (NOTE: the accuracy of this amplitude reading is very critical to the bond index calculations). Next, find the amplitude corresponding to 0% bond. Some bond logs may not include a section with free pipe. In this instance, choose the appropriate free-pipe travel time from the service company charts for your specific tool, or from the generalized chart (TABLE 2) at the end of this guidance. To calculate a bond index of 80%, use the following equation:

$$A_{80} = 10^{[(0.2)\log(A_0) + (0.8)\log(A_{100})]}$$

where:

A_{80} = Amplitude at 80% bond (mV)

A_0 = Amplitude at 0% bond (mV)
A_{100} = Amplitude at 100% bond (mV)

EXAMPLE:

As an example, consider a bond log showing the following conditions:

- Free pipe (0% bond) amplitude at 81 mV.

- 100 % bond amplitude at 1 mV.

Substituting the above values into the equation results in:

$$A_{80} = 10^{[(0.2)\log(81) + (0.8)\log(1)]}$$

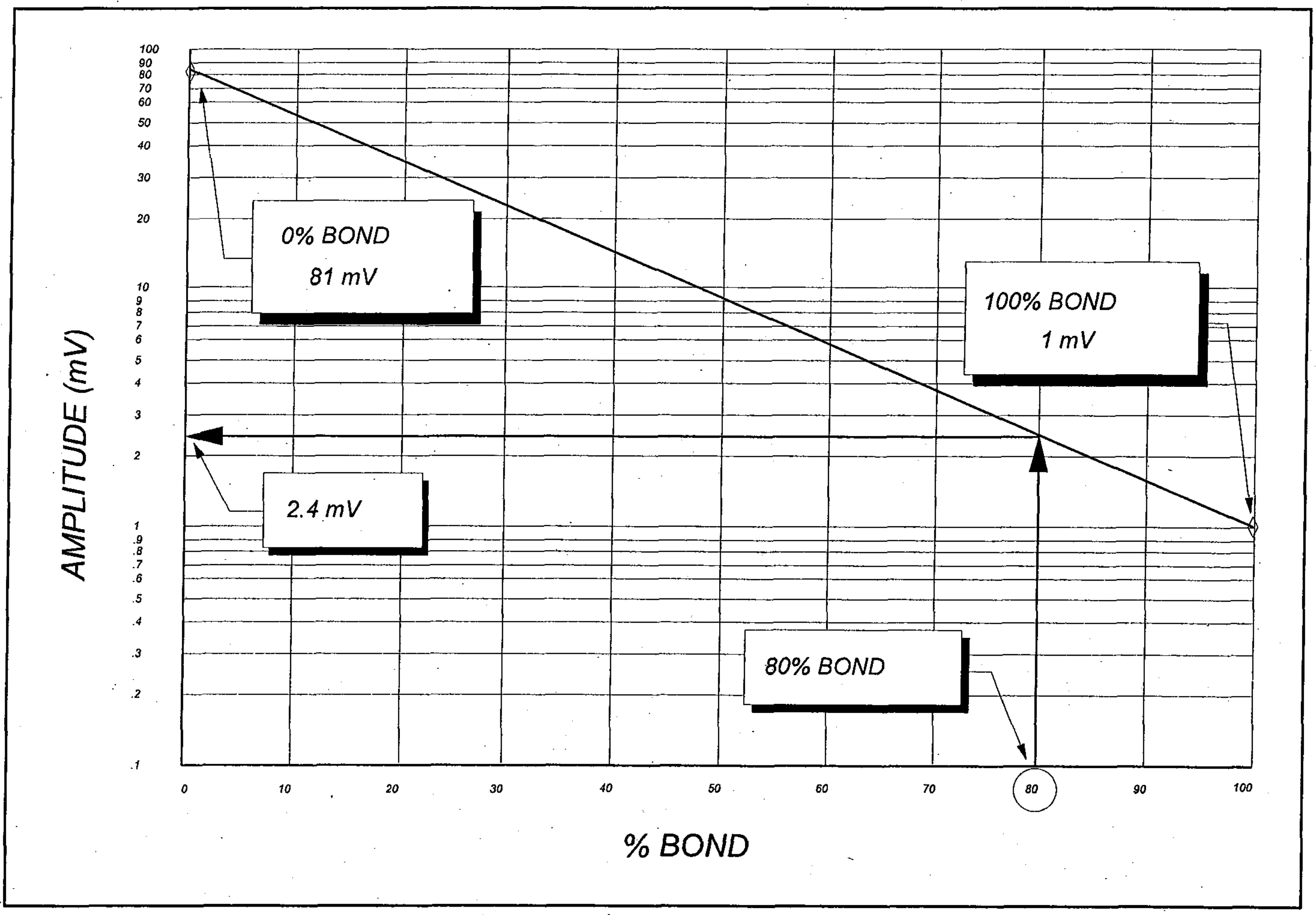
$$A_{80} = 2.41 mV$$

Another way to calculate the amplitude at 80% bond is by plotting these same log readings on a semi-log chart.

Plot the values for 0% Bond and 100% Bond vs. their respective Amplitudes on a semi-log chart - amplitudes on the log scale (y-axis), and bond indices on the linear scale (x-axis). Then, connect the points with a straight line.

To estimate the amplitude corresponding to an 80% Bond Index, enter the graph on the x-axis at 80% bond. Draw a straight line upward until you reach the diagonal line connecting the 0% and 100% points. Continue by drawing a horizontal line to the y-axis. This point on the y-axis is the amplitude corresponding to an 80% Bond Index.

Using the values from the example above, your chart will look like that shown below:



In this example, <u>80% bond shows an amplitude of 2.4 mV</u>.

A convenient way to evaluate the log is to draw a line on the bond log's **amplified** amplitude (5X) track corresponding to the calculated 80% bond amplitude. Whenever the logged **amplified** amplitude (5X) curve drops below (to the left of) the drawn line, this indicates a bond of 80% or more.

PART IV - CONCLUSIONS - REMINDERS

Different pipe weights and cement types will affect the log readings, so be mindful of these factors in wells with varying pipe weights and staged cement or squeeze jobs.

Collars generally do not show up on the VDL track in well-bonded sections of casing.

Longer (slower) travel time due to cycle skipping or cycle stretch usually suggests good bonding.

Shorter (faster) travel times indicate a de-centered tool or a fast formation and will provide erroneous amplitude readings that make evaluation impossible through that section of the log. Fast formations do not assure that the cement contacts the formation all around the borehole.

Although the bond index is important, you should not base your assessment of the cement quality on that one factor alone. You should use the VDL to support any indication of bonding. Also, you must know how each portion of the CBL (VDL, travel time, amplitude, etc.) influences another.

Most 3'-5' CBL's cannot identify a 1/2" channel in cement. Therefore, you also need to consider the thickness of a cemented section needed to provide zone isolation. For adequate isolation in injection wells, the log should indicate a continuous 80% or greater bond through the following intervals as seen in TABLE 1, below:

TABLE 1 - INTERVALS FOR ADEQUATE BOND

PIPE DIAMETER (in)	CONTINUOUS INTERVAL WITH BOND ≥ 80% (ft)
4-1/2	15
5	15
5-1/2	18
7	33
7-5/8	36
9-5/8	45
10-3/4	54

Adequately bonded cement by itself will not prevent fluid movement. If the bond log shows adequate bond through an interval where the geology allows fluid to move (permeable and/or fractured zones), fluids may move around perfectly bonded cement by travelling through the formation. Always cross-check your bond log with open hole logs to see that you have adequate bonding through the proper interval(s).

TABLE 2 - TRAVEL TIMES AND AMPLITUDES FOR FREE PIPE
(3 FT RECEIVER)

CASING SIZE (in)	CASING WEIGHT (lb/ft)	TRAVEL TIME (µs)		AMPLITUDE (mV)
		1-11/16" TOOL	3-5/8" TOOL	
4-1/2	9.5	252	233	81
	11.6	250	232	81
	13.5	249	230	81
5	15.0	257	238	76
	18.0	255	236	76
	20.3	253	235	76
5-1/2	15.5	266	248	72
	17.0	265	247	72
	20.0	264	245	72
	23.0	262	243	72
7	23.0	291	271	62
	26.0	289	270	62
	29.0	288	268	62
	32.0	286	267	62
	35.0	284	265	62
	38.0	283	264	62
7-5/8	26.4	301	281	59
	29.7	299	280	59
	33.7	297	278	59
	39.0	295	276	59
9-5/8	40.0	333	313	51
	43.5	332	311	51
	47.0	330	310	51
	53.5	328	309	51
10-3/4	40.5	354	333	48
	45.5	352	332	48
	51.0	350	330	48
	55.5	349	328	48

SUBJECT: GROUND WATER SECTION GUIDANCE NO. 35
Procedures to follow when excessive annular pressure is observed on a well.

FROM: Tom Pike, Chief
UIC Direct Implementation Section

TO: All Section Staff
Montana Operations Office

The following procedure is intended as an aid to UIC field inspectors when they encounter excessive annular pressure on a well. Excessive annular pressure is defined as 100 psi or 10% of the tubing pressure, whichever is less.

Usually, annular pressure is a direct indication of a loss of mechanical integrity. In some instances, recurring annular pressure may be caused by fluctuations in the temperature of the injected fluid. These temperature fluctuations may cause the annular pressure to increase when a hot fluid is being injected and decrease as the temperature of the injected fluid cools. The presence of temperature-induced pressure on the annulus does not indicate a malfunction in the casing/tubing/packer system and is not considered a loss of mechanical integrity. Wells exhibiting recurring temperature-induced annular pressure may be allowed to continue injecting if a temperature monitoring program is approved and followed.

This guidance was written to help determine the cause of annular pressure. When the procedures in this guidance are followed, any major mechanical integrity problems (a breech in the casing/tubing/packer system) will become apparent quickly. A quick determination will allow the operator to begin follow-up procedures immediately to prevent contamination to USDWs.

Use Section Guidance No. 35 to determine <u>if</u> the well has experienced a loss of mechanical integrity. If you find that there <u>is</u> a loss of mechanical integrity, use *Headquarters Guidance No. 76. - Follow-up to loss of Mechanical Integrity for Class II Wells* to bring the well back into compliance. The use of Section Guidance No. 35 is not to be confused with, nor does it supersede any provision of Headquarters Guidance No. 76. Instead, the two guidance documents are meant to work together to identify and to remedy any potential mechanical integrity failure.

A flowchart for Section Guidance No. 35 is included for quick reference in the field.

PROCEDURES TO FOLLOW WHEN EXCESSIVE ANNULAR PRESSURE IS OBSERVED

During field inspections, the following procedures should be followed when excessive annular pressure is observed. Excessive annular pressure is defined as 100 psi or 10% of the tubing pressure, whichever is less.

NOTE CONDITIONS AT THE WELL

Note tubing and annular pressure readings, and the operating status of the well (injecting, shut-in, etc.) on the UIC inspection form.

SEE IF ANNULUS PRESSURE WILL BLEED-OFF

Attempt to bleed the pressure from the annulus by having the operator open the annulus (for a maximum of sixty seconds).

It is the operator's responsibility to collect and dispose of any fluids bled from the annulus.

DID THE ANNULAR PRESSURE BLEED TO 0 PSI WITHIN SIXTY SECONDS?

YES

Have the operator close the annulus.

On your inspection form note the volume of fluid (or gas) bled from the annulus during the sixty seconds, and the tubing and annulus pressures.

NO

Have the operator close the annulus.

On your inspection form note the volume of fluid (or gas) bled from the annulus during the sixty seconds, and the tubing and annulus pressures.

Have the operator shut the well in for 2 hours, and if possible, bleed pressure from the injection tubing. Record the tubing and annulus pressure after two hours.

Bleed off the annulus for 60 seconds. Record the tubing and annulus pressures after bleed-off, and estimate the volume bled off.

INFORM THE OPERATOR THAT THE WELL HAS AN APPARENT MECHANICAL INTEGRITY FAILURE and provide the operator with the guidance that discusses OPERATOR RESPONSIBILITIES FOLLOWING MECHANICAL INTEGRITY FAILURES.

END PROCEDURE.

SEE IF PRESSURE RETURNS WITHIN 15 MINUTES

Continue to monitor the well for annulus pressure return for at least 15 minutes after the annulus valve is closed.

	YES	NO
DOES PRESSURE RETURN TO THE ANNULUS AFTER 15 MINUTES?	On your inspection form, note the annulus and tubing pressures recorded after 15 minutes. Have the operator shut the well in for 2 hours, and if possible, bleed pressure from the injection tubing. Record the tubing and annulus pressure after two hours. Bleed off the annulus for 60 seconds. Record the tubing and annulus pressures after bleed-off, and estimate the volume bled off. INFORM THE OPERATOR THAT THE WELL HAS AN APPARENT MECHANICAL INTEGRITY FAILURE and provide the operator with the guidance that discusses OPERATOR RESPONSIBILITIES FOLLOWING MECHANICAL INTEGRITY FAILURES. **END PROCEDURE.**	Require the operator to monitor and report to EPA with the annulus and tubing pressures for at least 14 days to see if pressure returns to the annulus. Instruct the operator to contact EPA as soon as any pressure returns to the annulus.
DOES PRESSURE RETURN TO THE ANNULUS WITHIN 14 DAYS?	EPA Technical Expert will design a proper Mechanical Integrity test. Compliance officer will require the operator to conduct the test within 14 days.	The well is considered to have mechanical integrity. **END PROCEDURE.**
DOES THE WELL PASS THE MIT?	Require the operator to monitor and report to EPA with the annulus and tubing pressures for at least 14 days to see if pressure returns to the annulus. Instruct the operator to contact EPA as soon as any	INFORM THE OPERATOR THAT THE WELL HAS AN APPARENT MECHANICAL INTEGRITY FAILURE and provide the operator with the guidance that discusses OPERATOR RESPONSIBILITIES FOLLOWING MECHANICAL INTEGRITY FAILURES. END PROCEDURE.

<u>DOES PRESSURE RETURN TO THE ULUS WITHIN DAYS?</u>

<u>YES</u>

EPA Technical Expert will design a proper Monitoring Program to determine the cause of recurrent annular pressure.

Compliance officer will require the operator to begin the Monitoring program within 14 days.

Conduct unannounced inspections at the well during the Monitoring Program.

<u>NO</u>

The well is considered to have mechanical integrity.

END PROCEDURE.

<u>IS THE ANNULUS PRESSURE CAUSED BY TEMPERATURE?</u>

<u>YES</u>

EPA Technical Expert will design a proper Temperature Monitoring Program that allows injection to continue while tracking relationship between temperature and recurrent annulus pressure.

Compliance officer will require the operator to cease injection immediately if the operator fails to follow the Temperature Monitoring Program.

Compliance officer will require the operator to cease injection immediately if recurrent annular pressures cannot be explained by the results of the Temperature Monitoring Program.

Compliance officer will require annual Mechanical Integrity Tests using the standard pressure method.

<u>NO</u>

INFORM THE OPERATOR THAT THE WELL HAS AN APPARENT MECHANICAL INTEGRITY FAILURE and provide the operator with the guidance that discusses OPERATOR RESPONSIBILITIES FOLLOWING MECHANICAL INTEGRITY FAILURES.

END PROCEDURE.

14-DAY PRESSURE MONITORING

Please use this form to report data for a 14-day period after pressure is bled from the tubing-casing annulus. Please telephone EPA in Denver as soon as possible when/if pressure returns to the annulus. This data will be used to determine the cause(s) of recurrent annular pressure.

NOTE: DO NOT BLEED PRESSURE FROM ANNULUS DURING THE 14-DAY MONITORING PERIOD.

	DATE	TIME	ANNULUS PRESSURE (psi)	TUBING PRESSURE (psi)	WELL INJECTING (YES/NO)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					

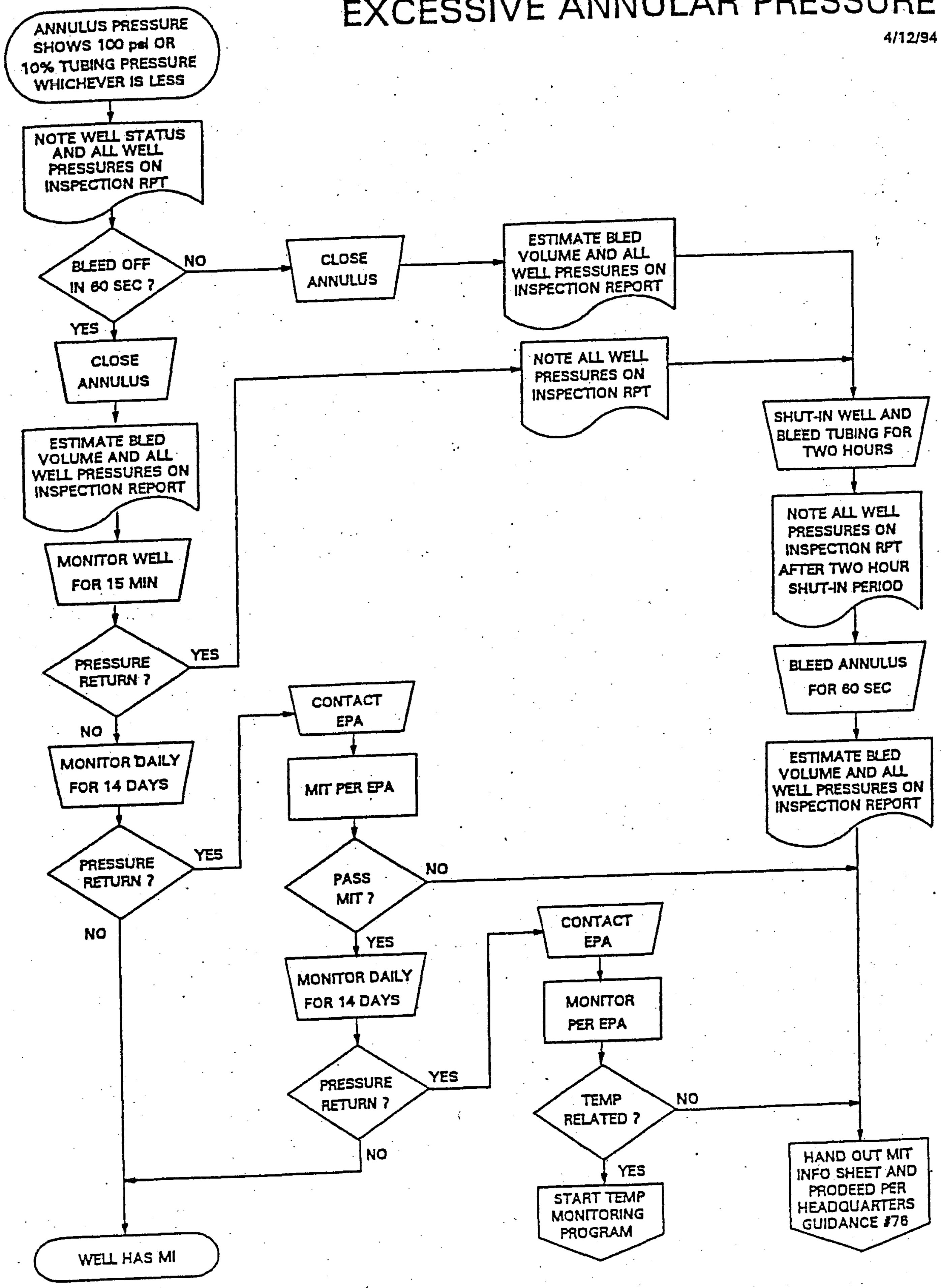
ELL NAME: ______________________________

ATOR: ______________________________

IGNATURE: ______________________________ DATE: ________________

EXCESSIVE ANNULAR PRESSURE

4/12/94



UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION VIII
999 18th STREET - SUITE 500
DENVER, COLORADO 80202-2466

OPERATOR RESPONSIBILITIES FOLLOWING MECHANICAL INTEGRITY FAILURES

1) **IMMEDIATELY** - Cease injection and shut-in the well as rapidly as feasible. In no case shall the well remain in operation beyond 48 hours unless Tom Pike, Chief, Underground Injection Control Implementation (UIC-I) Section [(303) 293-1544] allows for temporary operation of the well.

2) **WITHIN 24 HOURS** - Verbally notify the UIC-I Section Chief of MIT failure even in cases where the failure is detected during a test which was witnessed by a UIC inspector.

3) **WITHIN 5 DAYS** - Submit a written follow-up report documenting test results, remediation taken or a proposed remediation plan and any limits established by the Director on appropriate volume or time for continued injection operation.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION VIII
999 18th STREET - SUITE 300
DENVER, COLORADO 80202-2466

SUBJECT: <u>GROUND WATER SECTION GUIDANCE NO. 37</u>
Demonstrating Part II (external) Mechanical Integrity for a Class II injection well permit.

FROM: Tom Pike, Chief
UIC Direct Implementation Section

TO: All Section Staff
Montana Operations Office

During the review for a Class II injection well permit, consideration must be given to the mechanical integrity (MI) of the well. MI demonstrates that the well is in sound condition and that the well is constructed in a manner that prevents injected fluids from entering any formation other than the authorized injection formation.

A demonstration of MI is a two part process:

<u>PART I</u> - **INTERNAL MECHANICAL INTEGRITY** is an assurance that there are no significant leaks in the casing/tubing/packer system.

<u>PART II</u> - **EXTERNAL MECHANICAL INTEGRITY** demonstrates that after fluid is injected into the formation, the injected fluids will not migrate out of the authorized injection interval through vertical channels adjacent to the wellbore.

A Class II injection well may demonstrate <u>Part II</u> MI by showing that injected fluids remain within the authorized injection interval. This may be accomplished as follows:

1) Cement bond log showing 80% bond through the an appropriate interval (Section Guidance 34),

2) Radioactive tracer survey conducted according to a EPA-approved procedure, or

3) Temperature survey conducted according to a EPA-approved procedure (Section Guidance 38).

For each test option above, the operator of the injection well should submit a plan for conducting the test. The plan will then be approved (or modified and approved) by EPA. EPA's pre-approval of the testing method will assure the operator that the test is conducted consistent with current EPA guidance, and that the test will provide meaningful results.

Part II MI may be demonstrated either before or after issuing the Final Permit. However, if Part II is to be demonstrated after the Final Permit is issued, a provision in the permit will require the demonstration of Part II MI. The well will also be required to pass Part II MI prior to granting authorization to inject.

Radioactive tracer surveys and temperature surveys require that the well be allowed to inject fluids as part of the procedure. In these cases, a well that has shown no other demonstration of Part II MI will be allowed to inject only that volume of fluid that is necessary to conduct the appropriate test.

After the results of the test proves that the well has passed Part II MI, the well will be given authorization to begin full injection operations.

If any of the tests show a lack of Part II MI, the well will be repaired and retested, or plugged (See Headquarters Guidance #76).

Mechanical Integrity Test
Casing or Annulus Pressure Mechanical Integrity Test

U.S. Environmental Protection Agency
Underground Injection Control Program, UIC Direct Implementation Program 8P-W-GW
999 18th Street, Suite 500 Denver, CO 80202-2466

EPA Witness: ______________________ Date: ____/____/____
Test conducted by: ______________________
Others present: ______________________

Well Name: ______________________ Type: ER SWD Status: AC TA UC
Field: ______________________
Location: ________ Sec: ____ T ____ N / S R ____ E / W County: ____________ State: ____
Operator: ______________________
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: ____________ psig

MIT DATA TABLE	Test #1	Test #2	Test #3
TUBING PRESSURE			
Initial Pressure	psig	psig	psig
End of test pressure	psig	psig	psig
CASING / TUBING ANNULUS PRESSURE			
0 minutes	psig	psig	psig
5 minutes	psig	psig	psig
10 minutes	psig	psig	psig
15 minutes	psig	psig	psig
20 minutes	psig	psig	psig
25 minutes	psig	psig	psig
30 minutes	psig	psig	psig
minutes	psig	psig	psig
minutes	psig	psig	psig
RESULT	[ ] Pass [ ]Fail	[ ] Pass [ ]Fail	[ ] Pass [ ]Fail

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION VIII
999 18th STREET - SUITE 500
DENVER, COLORADO 80202-2466

SUBJECT: <u>GROUND WATER SECTION GUIDANCE NO. 39</u>
Pressure testing injection wells for Part I (internal) Mechanical Integrity

FROM: Tom Pike, Chief
UIC Direct Implementation Section

TO: All Section Staff
Montana Operations Office

<u>Introduction</u>

The Underground Injection Control (UIC) regulations require that an injection well have mechanical integrity at all times (40 CFR 144.28 (f)(2) and 40 CFR 144.51 (q)(1)). A well has mechanical integrity (40 CFR 146.8) if:

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

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

Definition: Mechanical Integrity Pressure Test for Part I. A pressure test used to determine the integrity of all the downhole components of an injection well, usually tubing, casing and packer. It is also used to test tubing cemented in the hole by using a tubing plug or retrievable packer. Pressure tests must be run at least once every five years. **If for any reason the tubing/packer is pulled, the injection well is required to pass another mechanical integrity test of the tubing casing and packer prior to recommencing injection regardless of when the last test was conducted. Tests run by operators in the absence of an EPA inspector must be conducted according to these procedures and recorded on either the attached form or an equivalent form containing the necessary information. A pressure recording chart documenting the actual annulus test pressures must be attached to the form.**

This guidance addresses making a determination of Part I of Mechanical Integrity (no leaks in the tubing, casing or packer). <u>The Region's policy is: 1) to determine if there are significant leaks in the tubing, casing or packer; 2) to assure that the casing can withstand pressure similar to that which</u>

would be applied if the tubing or packer fails; 3) to make the Region's test procedure consistent with the procedures utilized by other Region VIII Primacy programs; and 4) to provide a procedure which can be easily administered and is applicable to all class I and II wells. Although there are several methods allowed for determining mechanical integrity, the principal method involves running a pressure test of the tubing/casing annulus. Region VIII's procedure for running a pressure test is intended to aid UIC field inspectors who witness pressure tests for the purpose of demonstrating that a well has Part I of Mechanical Integrity. The guidance is also intended as a means of informing operators of the procedures required for conducting the test in the absence of an EPA inspector.

Pressure Test Description

Test Frequency

The mechanical integrity of an injection well must be maintained at all times. Mechanical integrity pressure tests are required at least every five (5) years. **If for any reason the tubing/packer is pulled, however, the injection well is required to pass another mechanical integrity test prior to recommencing injection regardless of when the last test was conducted. The Regional UIC program must be notified of the workover and the proposed date of the pressure test. The well's test cycle would then start from the date of the new test if the well passes the test and documentation is adequate.** Tests may be required on a more frequent basis depending on the nature of the injectate and the construction of the well (see Section guidance on MITs for wells with cemented tubing and regulations for Class I wells).

Region VIII's criteria for well testing frequency is as follows:

1. Class I hazardous waste injection wells; initially [40 CFR 146.68(d)(1)] and annually thereafter;

2. Class I non-hazardous waste injection wells; initially and every two (2) years thereafter, except for old permits (such as the disposal wells at carbon dioxide extraction plants which require a test at least every five years);

3. Class II wells with tubing, casing and packer; initially and at least every five (5) years thereafter;

4. Class II wells with tubing cemented in the hole; initially and every one (1) or two (2) years thereafter

depending on well specific conditions (See Region VIII UIC Section Guidance #36);

5. Class II wells which have been temporarily abandoned (TAd) must be pressure tested after being shut-in for two years; and

6. Class III uranium extraction wells; initially.

Test Pressure

To assure that the test pressure will detect significant leaks and that the casing is subjected to pressure similar to that which would be applied if the tubing or packer fails, the tubing/casing annulus should be **tested at a pressure equal to the maximum allowed injection pressure or 1000 psig whichever is less. The annular test pressure must, however, have a difference of at least 200 psig either greater or less than the injection tubing pressure. Wells which inject at pressures of less than 300 psig must test at a minimum pressure of 300 psig, and the pressure difference between the annulus and the injection tubing must be at least 200 psi.**

Test Criteria

1. The duration of the pressure test is 30 minutes.

2. Both the annulus and tubing pressures should be monitored and recorded every five (5) minutes.

3. If there is a pressure change of 10 percent or more from the initial test pressure during the 30 minute duration, the well has failed to demonstrate mechanical integrity and should be shut-in until it is repaired or plugged.

4. A pressure change of 10 percent or more is considered significant. If there is no significant pressure change in 30 minutes from the time that the pressure source is disconnected from the annulus, the test may be completed as passed.

Recordkeeping and Reporting

The test results must be recorded on the attached form. The annulus pressure should be recorded at five (5) minute intervals. Tests run by operators in the absence of an EPA inspector must be conducted according to these procedures and recorded on the attached form or an equivalent form and a pressure recording chart documenting the actual annulus test pressures must be attached to the submittal. The tubing pressure at the beginning and end of each test must be recorded. The volume of the annulus fluid bled back at the surface after the test should be measured and recorded on the form. This can be done by bleeding the annulus pressure off and discharging the associated fluid into a five gallon container. The volume information can be used to verify the approximate location of the packer.

Procedures for Pressure Test

1. Scheduling the test should be done at least two (2) weeks in advance.

2. Information on the well completion (location of the packer, location of perforations, previous cement work on the casing, size of casing and tubing, etc.) and the results of the previous MIT test should be reviewed by the field inspector in advance of the test. Regional UIC Guidance #35 should also be reviewed. Information relating to the previous MIT and any well workovers should be reviewed and taken into the field for verification purposes.

3. All Class I wells and Class II SWD wells should be shut-in prior to the test. A 12 to 24-hour shut-in is preferable to assure that the temperature of the fluid in the wellbore is stable.

4. Class II enhanced recovery wells may be operating during the test, but it is recommended that the well be shut-in if possible.

5. The operator should fill the casing/tubing annulus with inhibited fluid at least 24 hours in advance, if possible. Filling the annulus should be undertaken through one valve with the second valve open to allow air to escape. After the operator has filled the annulus, a check should be made to assure that the annulus will remain full. If the annulus can not maintain a full column of fluid, the operator should notify the Director and begin a rework. The operator should measure and report the volume of fluid added to the annulus. If not already the case, the casing/tubing valves should be closed, at least, 24 hours prior to the pressure test.

Following steps are at the well:

6. Read tubing pressure and record on the form. If the

well is shut-in, the reported information on the actual maximum operating pressure should be used to determine test pressures.

7. Read pressure on the casing/tubing annulus and record value on the form. If there is pressure on the annulus, it should be bled off prior to the test. If the pressure will not bleed-off, the guidance on well failures (Region VIII UIC Section Guidance #35) should be followed.

8. Ask the operator for the date of the last workover and the volume of fluid added to the annulus prior to this test and record information on the form.

9. Hook-up well to pressure source and apply pressure until test value is reached.

10. Immediately disconnect pressure source and start test time (If there has been a significant drop in pressure during the process of disconnection, the test may have to be restarted). The pressure gages used to monitor injection tubing pressure and annulus pressure should have a pressure range which will allow the test pressure to be near the mid-range of the gage. Additionally, the gage must be of sufficient accuracy and scale to allow an accurate reading of a 10 percent change to be read. For instance, a test pressure of 600 psi should be monitored with a 0 to 1000 psi gage. The scale should be incremented in 20 psi increments.

11. Record tubing and annulus pressure values every five (5) minutes.

12. At the end of the test, record the final tubing pressure.

13. If the test fails, check the valves, bull plugs and casing head close up for possible leaks. The well should be retested.

14. If the second test indicates a well failure, the Region should be informed of the failure within 24 hours by the operator, and the well should be shut-in within 48 hours per Headquarters guidance #76. A follow-up letter should be prepared by the operator which outlines the cause of the MIT failure and proposes a potential course of action. This report should be submitted to EPA within five days.

15. Bleed off well into a bucket, if possible, to obtain a volume estimate. This should be compared to the calculated value obtained using the casing/tubing annulus volume and fluid compressibility values.

16. Return to office and prepare follow-up.

Alternative Test Option

While it is expected that the test procedure outlined above will be applicable to most wells, the potential does exist that unique circumstances may exist for a given well that precludes or makes unsafe the application of this test procedure. In the event that these **exceptional or extraordinary** conditions are encountered, the operator has the option to propose an alternative test or monitoring procedures. The request must be submitted by the operator in writing and must be approved in writing by the UIC-Implementation Section Chief or equivalent level of management.

Attachment

Mechanical Integrity Test
Casing or Annulus Pressure Mechanical Integrity Test

U.S. Environmental Protection Agency
Underground Injection Control Program, UIC Direct Implementation Program 8P-W-GW
999 18th Street, Suite 500 Denver, CO 80202-2466

EPA Witness: ______________________ Date: ___/___/___
Test conducted by: ______________________
Others present: ______________________

Well Name: ______________________	Type: ER SWD	Status: AC TA UC
Field: ______________________		
Location: ________ Sec: ____ T ____ N / S R ____ E / W	County: ______________	State: ___
Operator: ______________________		
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: ______________ psig

MIT DATA TABLE	Test #1	Test #2	Test #3
TUBING PRESSURE			
Initial Pressure	psig	psig	psig
End of test pressure	psig	psig	psig
CASING / TUBING ANNULUS PRESSURE			
0 minutes	psig	psig	psig
5 minutes	psig	psig	psig
10 minutes	psig	psig	psig
15 minutes	psig	psig	psig
20 minutes	psig	psig	psig
25 minutes	psig	psig	psig
30 minutes	psig	psig	psig
minutes	psig	psig	psig
minutes	psig	psig	psig
RESULT	[ ] Pass [ ]Fail	[ ] Pass [ ]Fail	[ ] Pass [ ]Fail

EPA

UNDERGROUND INJECTION CONTROL PROGRAM

PERMIT

PREPARED: December 2005

Permit No. UT20994-06735

Class II Enhanced Oil Recovery Injection Well

Blackjack Federal 12-10-9-17
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 12-10-9-17 1999' FSL & 730' FWL, NWSW S10, T9S, R17E Duchesne County, UT

Permit requirements herein are based on regulations found in 40 CFR Parts 124, 144, 146, and 147 which are in effect on the Effective Date of this Permit. Issuance of this Permit does not convey any property rights of any sort, nor does it authorize any injury to persons or property or invasion of other private rights, or any infringement of other federal, State or local law or regulation.

This Permit is based on representations made by the applicant and on other information contained in the Administrative Record. Misrepresentation of information or failure to fully disclose all relevant information may be cause for termination, revocation and reissuance, or modification of this Permit and/or formal enforcement action. This Permit will be reviewed periodically to determine whether action under 40 CFR 144.36(a) is required.

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 30 2005

Effective Date DEC 30 2005

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 prevents the movement of fluids into or between underground sources of drinking water. 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. The well shall be plugged in accordance with the approved plugging and abandonment plan and with 40 CFR 146.10.

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 diagram.

The Blackjack Federal Federal No. 12-10-9-17 was drilled to a total depth of 5785 feet in the Basal Carbonate Member of the Green River Formation.

SURFACE CASING: 8-5/8 inch set at 309.28 feet in a 12-1/4 inch hole. Secured with 150 sacks of Class "G" cement which was circulated to the surface.

BASE OF USDWs: Less than 75 feet in the Uinta Formation.

PRODUCTION CASING: 5-1/2 inch set at 5768.23 feet in a 7-7/8 inch hole. Secured with 325 sacks of Premium Lite II Mixed and 425 sacks of 50/50 Pozmix. Operator picks top of cement (TOC) at 175 feet. EPA calculates TOC at 1325 feet.

The well construction schematic diagram identifies the production perforations in the Douglas Creek Member which will be utilized during enhanced recovery injection.

New injection perforations may be placed at the permittee's discretion within the approved injection zone, i.e., 3515 feet to the top of the Wasatch Formation which is estimated to be 5848 feet. Prior to adding new injection perforations in the approved interval, the permittee shall notify the Director. Upon concluding the addition of new perforations the permitee shall submit to the Director a Well Rework Report (Form No. 7520-12) and a schematic diagram.

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

Blackjack Federal 12-10-9-17

Spud Date: 7/17/2004
Put on Production: 8/16/2004
GL: 5172' KB: 5184'

Proposed Injection
Wellbore Diagram

Initial Production: BOPD, MCFD, BWPD

SURFACE CASING Base USDWs 475'

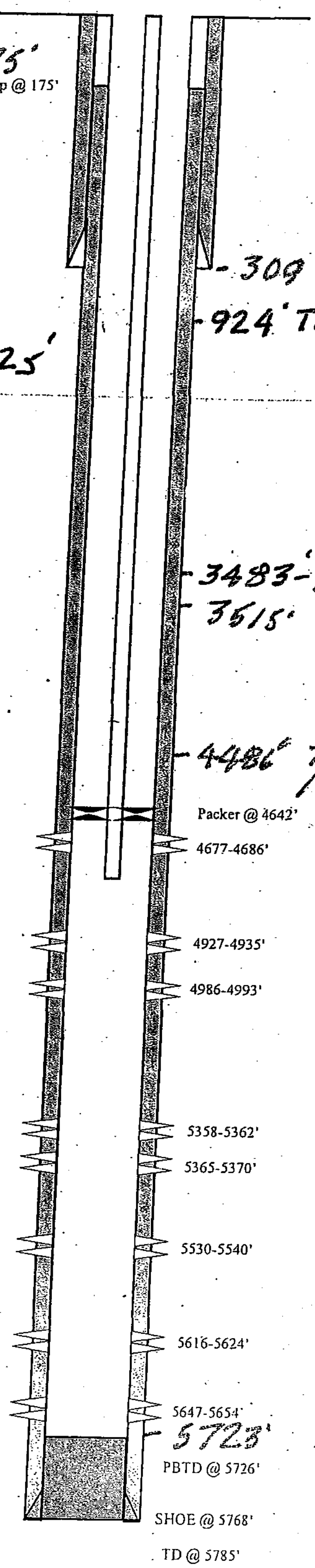
CSG SIZE: 8 5/8"
GRADE: J-55
WEIGHT: 24#
LENGTH: 7 jts. (299.28')
DEPTH LANDED: 309.28' KB
HOLE SIZE: 12 1/4"
CEMENT DATA: 150 sxs Class "G" mixed cmt, est 4 bbls cmt to surf.

PRODUCTION CASING Green River 1325'

CSG SIZE: 5 1/2"
GRADE: J-55
WEIGHT: 15.5#
LENGTH: 134 jts. (5770.23')
DEPTH LANDED: 5768.23' KB
HOLE SIZE: 7 7/8"
CEMENT DATA: 325 sxs Prem. Lite II mixed & 425 sxs 50/50 POZ mix.
CEMENT TOP AT: 175'

TUBING

SIZE/GRADE/WT.: 2 7/8" / J-55 / 6.5#
NO. OF JOINTS: 169 jts (5494.08')
TUBING ANCHOR: 5508.83' KB
NO. OF JOINTS: 2 jts (65.14')
SEATING NIPPLE: 2 7/8" (1.10')
SN LANDED AT: 5575.47' KB
NO. OF JOINTS: 2 jts (65.12')
TOTAL STRING LENGTH: EOT @ 5641.09'



FRAC JOB

08/10/04 5530-5654' **Frac CP5 and 4 sands as follows:** 39,909# 20/40 sand in 382 bbls Lightning 17 frac fluid. Treated @ avg press of 1521 psi w/avg rate of 24.7 BPM. ISIP 1850 psi Calc flush: 5528 gal. Actual flush: 5527 gal.

08/10/04 5358-5370' **Frac CP1 sands as follows:** 37,686# 20/40 sand in 357 bbls Lightning 17 frac fluid. Treated @ avg press of 1346 psi w/avg rate of 24.8 BPM. ISIP 1600 psi. Calc flush: 5356 gal. Actual flush: 5355 gal.

08/10/04 4927-4993' **Frac A1 and A3 sands as follows:** 33,275# 20/40 sand in 335 bbls Lightning 17 frac fluid. Treated @ avg press of 1711 psi w/avg rate of 24.7 BPM. ISIP 2000 psi. Calc flush: 4925 gal. Actual flush: 4914 gal.

08/10/04 4677-4686' **Frac C sands as follows:** 15,212# 20/40 sand in 220 bbls Lightning 17 frac fluid. Treated @ avg press of 2012 psi w/avg rate of 24.6 BPM. ISIP 2230 psi. Calc flush: 4675 gal. Actual flush: 4591 gal.

PERFORATION RECORD

8/06/04	5647-5654'	4 JSPF	28 holes
8/06/04	5616-5624'	4 JSPF	32 holes
8/06/04	5530-5540'	4 JSPF	40 holes
8/10/04	5365-5370'	4 JSPF	20 holes
8/10/04	5358-5362'	4 JSPF	16 holes
8/10/04	4986-4993'	4 JSPF	28 holes
8/10/04	4927-4935'	4 JSPF	32 holes
8/10/04	4677-4686'	4 JSPF	36 holes

NEWFIELD

Blackjack Federal 12-10-9-17
1999' FSL & 730' FWL
NW/SW Section 10-T9S-R17E

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.

The permittee shall demonstrate Part II MI by either 1) running and submitting a new, centralized CBL, or 2) by conducting a Part II MI test using a Radioactive Tracer Survey (RTS) within a 180-day period following commencement of injection.

Part II MI will be considered demonstrated 1) if the new centralized CBL results identify adequate casing cement of at least eighteen (18) feet of effective 80% bond index cement bond across the Confining Zone, or 2) if the RTS is able to demonstrate no fluid movement through vertical channels adjacent to the well bore.

If the new, centralized CBL is not able to identify adequate casing cement of at least eighteen (18) feet of effective 80% bond index cement bond across the Confining Zone, the RTS will be required within a 180-day period following commencement of injection. If the RTS is used, a Part II MI demonstration, using a temperature log, noise log, or RTS is required at least once every five years thereafter.

WELL NAME: Blackjack Federal 12-10-9-17

TYPE OF TEST	DATE DUE
Radioactive Tracer Survey (2)	If a new CBL does not demonstrate Part II MI, then within 180 days following commencement of injection the permittee shall run a Radioactive Trace Survey. A Radioactive Tracer Survey shall be run at least once every five years thereafter.
Pore Pressure	Prior to authorization to inject.
Standard Annulus Pressure	Part I MIT. Prior to authorization to inject, and at least once every five years thereafter.

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.

	MAXIMUM ALLOWED INJECTION PRESSURE (psi)
WELL NAME	**ZONE 1 (Upper)**
Blackjack Federal 12-10-9-17	1,385

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 12-10-9-17			
	APPROVED INJECTION INTERVAL (KB, ft)		**FRACTURE GRADIENT**
FORMATION NAME	**TOP**	**BOTTOM**	**(psi/ft)**
Green River: Garden Gulch-Douglas Creek-Basal Carbonate Members	3,515.00 -	5,848.00	0.730

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:

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

APPENDIX E

PLUGGING AND ABANDONMENT REQUIREMENTS

See diagram.

All cement plugs will be set wirh tubing.

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

Based upon the proposed enhanced recovery inejction perforations, the EPA has approved the following Plugging and Abandonment Plan.

PLUG NO. 1: Set a Cast Iron Bridge Plug (CIBP) at 4582 feet. Place 100 feet of Class "G" cement on CIBP.

PLUG NO. 2: Set a 200-foot balanced cement plug between 2000 feet and 2200 feet across water zone.

PLUG NO. 3: Place a cement plug inside of the 5-1/2 inch casing from the surface to a depth of 359 feet.

PLUG NO. 4: Set cement plug from the surface to a depth of 359 feet on the backside of the 5-1/2 inch casing.

Attachment Q-2

Blackjack Federal 12-10-9-17

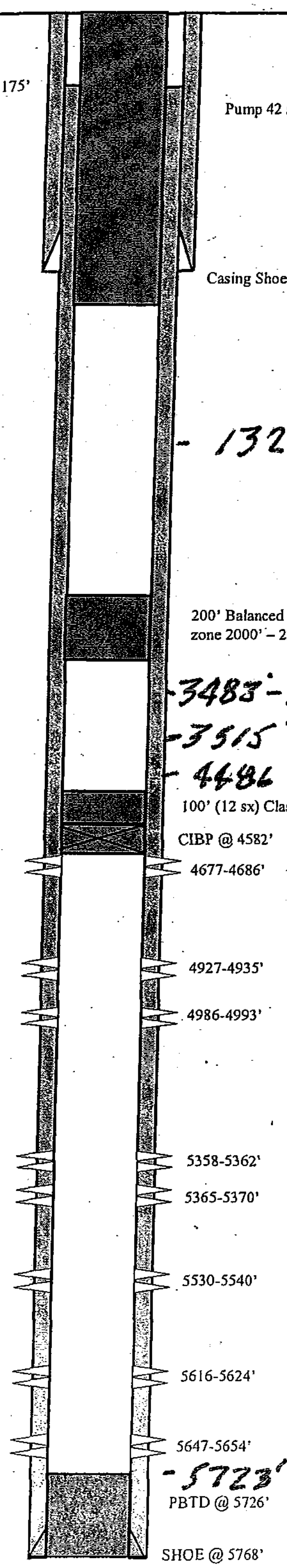
Spud Date: 7/17/2004
Put on Production: 8/16/2004
GL: 5172' KB: 5184'

Proposed P & A
Wellbore Diagram

Initial Production: BOPD, MCFD, BWPD

SURFACE CASING Base USDWs < 75
CSG SIZE: 8 5/8"
GRADE: J-55
WEIGHT: 24#
LENGTH: 7 jts. (299.28')
DEPTH LANDED: 309.28' KB
HOLE SIZE: 12 1/4"
CEMENT DATA: 150 sxs Class "G" mixed cmt, est 4 bbls cmt to surf.

PRODUCTION CASING
CSG SIZE: 5 1/2"
GRADE: J-55
WEIGHT: 15.5#
LENGTH: 134 jts. (5770.23')
DEPTH LANDED: 5768.23' KB
HOLE SIZE: 7 7/8"
CEMENT DATA: 325 sxs Prem. Lite II mixed & 425 sxs 50/50 POZ mix.
CEMENT TOP AT: 175'



NEWFIELD

Blackjack Federal 12-10-9-17
1999' FSL & 730' FWL
NW/SW Section 10-T9S-R17E
Duchesne Co, Utah
API #43-013-32505; Lease #UTU-70821

APPENDIX F

CORRECTIVE ACTION REQUIREMENTS

No corrective action is deemed necessary for this project.

STATEMENT OF BASIS

NEWFIELD PRODUCTION COMPANY
BLACKJACK FEDERAL 12-10-9-17
DUCHESNE COUNTY, UT

EPA PERMIT NO. UT20994-06735

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.

UIC Permits specify the conditions and requirements for construction, operation, monitoring and reporting, and plugging of injection wells to prevent the movement of fluids into underground sources of drinking water (USDWs). 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 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 conversion and operation of a "new" injection well or wells 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 Company 1401 Seventeenth Street Suite 1000 Denver, CO 80202

on

March 21, 2005

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

Blackjack Federal 12-10-9-17 1999' FSL & 730' FWL, NWSW S10, 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. 12-10-9-17 is currently an active Green River Formation-Douglas Creek Member oil well. The applicant intends to convert the Blackjack Federal No. 12-10-9-17 to an enhanced recovery injection well to support current Green River Formation enhanced recovery injection operations. The well was completed for production on August 16, 2004.

TABLE 1.1

WELL STATUS / DATE OF OPERATION

CONVERSION WELLS		
Well Name	**Well Status**	**Date of Operation**
Blackjack Federal 12-10-9-17	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 12-10-9-17

Formation Name	Top (ft)	Base (ft)	TDS (mg/l)	Lithology
Green River	1,325.00	5,848.00	9,059.00	Sand, shale, 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 injection zone for enhanced recovery is identified as the gross interval between the top of the Garden Gulch Member (3515 feet) and the top of the Wasatch Formation, estimated to be 5848 feet.

TABLE 2.2
INJECTION ZONES
Blackjack Federal 12-10-9-17

Formation Name	Top (ft)	Base (ft)	TDS (mg/l)	Fracture Gradient (psi/ft)	Porosity	Exempted?*
Green River: Garden Gulch-Douglas Creek-Basal Carbonate Members	3,515.00	5,848.00	9,059.00	0.730		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 Confining Zone is identified as a 32-foot shale interval (3483 feet to 3515 feet) overlying the Garden Gulch Member of the Green River Formation.

TABLE 2.3 CONFINING ZONES Blackjack Federal 12-10-9-17			
Formation Name	**Formation Lithology**	**Top (ft)**	**Base (ft)**
Green River	Shale	3,483.00	3,515.00

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. 12-10-9-17.

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 75 feet from the surface.

TABLE 2.4 UNDERGROUND SOURCES OF DRINKING WATER (USDW) Blackjack Federal 12-10-9-17				
Formation Name	**Formation Lithology**	**Top (ft)**	**Base (ft)**	**TDS (mg/l)**
Uinta	Sand, shale and minor carbonate	0.00	75.00	< 10,000.00
Green River	Sand, shale, carbonate	3,515.00	5,848.00	9,059.00

PART III. Well Construction (40 CFR 146.22)

TABLE 3.1 WELL CONSTRUCTION REQUIREMENTS Blackjack Federal 12-10-9-17				
Casing Type	**Hole Size (in)**	**Casing Size (in)**	**Cased Interval (ft)**	**Cemented Interval (ft)**
Production	7.88	5.50	0.00 - 5,768.23	924.00 - 5,768.23
Surface	12.25	8.63	0.00 - 309.28	0.00 - 309.00

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 Conditions of 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 11-10-9-17	Producer	No	5,775.00	752.00	No
Blackjack Federal 9-9-9-17	Producer	No	5,785.00	925.00	No
Monument Federal 12-10Y-9-17	Producer	No	5,554.00	1,504.00	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 12-10-9-17

Formation Name	Depth Used to Calculate MAIP (ft)	Fracture Gradient (psi/ft)	Initial MAIP (psi)
Green River: Garden Gulch-Douglas Creek-Basal Carbonate Members	4,677.00	0.730	1,385

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 "source water" from the Johnson Water District Reservoir. The calculated TDS of the water, as analyzed on January 10, 2005, is 694 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.

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 (Internal) MI: Part I MI will be demonstrated using a casing tubing pressure mechanical integrity test prior to beginning injection, and at least once every five (5) years thereafter. 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 (External) MI: The submitted cement record "Cement Bond Log-Gamma Ray-CCL" (CBL) Travel Time curve was off-scale and not calibrated indicating the CBL was not centralized. EPA analysis could not identify at least eighteen (18) feet of effective 80% bond index cement bond across the Confining Zone. Therefore, the permittee will be required to demonstrate Part II

MI by either: 1) running and submitting a new, centralized CBL, or 2) by conducting a Part II MI test using a Radioactive Tracer Survey (RTS) within a 180-day period following commencement of injection.

Part II MI will be considered demonstrated: 1) if the new centralized CBL results identify adequate casing cement of at least eighteen (18) feet of effective 80% bond index cement bond across the Confining Zone, or 2) if the RTS is able to demonstrate no fluid movement through vertical channels adjacent to the well bore. If the new, centralized CBL is not able to identify adequate casing cement of at least eighteen (18) feet of effective 80% bond index cement bond across the Confining Zone, the RTS will be required within a 180-day period following commencement of injection. If the RTS is used, a Part II MI demonstration, using a temperature log, noise log, or RTS is required at least once every five years thereafter.

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)

Plugging and Abandonment Plan

Prior to abandonment, the well or wells must be plugged with cement in a manner which will not allow the movement of fluids either into or between USDWs. The plugging and abandonment plan is described in Appendix E of the Permit.

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 cement plugs.

The following Plugging and Abandonment Plan, as proposed by the permittee, is predicated on the permittee not revising the injection perforations cited on the schematic diagram of well construction/conversion. Should the Permittee add new perforations, above the current uppermost perforations (4677 feet to 4686 feet), the EPA will modify the P&A Plan accordingly.

PLUG NO. 1: A Cast Iron Bridge Plug (CIBP) at 4582 feet with 100 feet of Class "G" cement on CIBP.

PLUG NO. 2: A 200-foot Class "G" cement plug over water zone 2000 feet to 2200 feet.

PLUG NO. 3: A Class "G" cement plug, within the 5-1/2 inch casing, from the surface to a depth

of 359 feet. PLUG NO. 4: A Class "G' cement plug on the backside of the 5-1/2 inch casing from the surface to a depth of 359 feet.

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:

Financial Statement, received April 22, 2005

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

STATE OF UTAH
DEPARTMENT OF NATURAL RESOURCES
DIVISION OF OIL, GAS AND MINING

SUNDRY NOTICES AND REPORTS ON WELLS

ɔ not use this form for proposals to drill new wells, significantly deepen existing wells below current bottom-hole depth, reenter plugged wells, to drill horizontal laterals. Use APPLICATION FOR PERMIT TO DRILL form for such proposals.

5. LEASE DESIGNATION AND SERIAL NUMBER: UTU70821
6. IF INDIAN, ALLOTTEE OR TRIBE NAME:
7. UNIT or CA AGREEMENT NAME: BLACKJACK UNIT
8. WELL NAME and NUMBER: BLACKJACK FEDERAL 12-10-9-17
9. API NUMBER: 4301332505
10. FIELD AND POOL, OR WILDCAT: Monument Butte

1. TYPE OF WELL: OIL WELL [X] GAS WELL [ ] OTHER

2. NAME OF OPERATOR: NEWFIELD PRODUCTION COMPANY

3. ADDRESS OF OPERATOR: Route 3 Box 3630 CITY Myton STATE UT ZIP 84052 PHONE NUMBER 435.646.3721

4. LOCATION OF WELL:
FOOTAGES AT SURFACE: 1999 FSL 730 FWL
COUNTY: Duchesne
OTR/OTR, SECTION, TOWNSHIP, RANGE, MERIDIAN: NW/SW, 10, T9S, R17E
STATE: Utah

11. CHECK APPROPRIATE BOXES TO INDICATE NATURE OF NOTICE, REPORT, OR OTHER DATA

TYPE OF ACTION SubDate

TYPE OF SUBMISSION	TYPE OF ACTION		
[ ] NOTICE OF INTENT (Submit in Duplicate)	[ ] ACIDIZE	[ ] DEEPEN	[ ] REPERFORATE CURRENT FORMATION
Approximate date work will	[ ] ALTER CASING	[ ] FRACTURE TREAT	[ ] SIDETRACK TO REPAIR WELL
	[ ] CASING REPAIR	[ ] NEW CONSTRUCTION	[ ] TEMPORARITLY ABANDON
	[ ] CHANGE TO PREVIOUS PLANS	[ ] OPERATOR CHANGE	[ ] TUBING REPAIR
	[ ] CHANGE TUBING	[ ] PLUG AND ABANDON	[ ] VENT OR FLAIR
[X] SUBSEQUENT REPORT (Submit Original Form Only)	[ ] CHANGE WELL NAME	[ ] PLUG BACK	[ ] WATER DISPOSAL
Date of Work Completion:	[X] CHANGE WELL STATUS	[ ] PRODUCTION (START/STOP)	[ ] WATER SHUT-OFF
05/15/2006	[ ] COMMINGLE PRODUCING FORMATIONS	[ ] RECLAMATION OF WELL SITE	[X] OTHER: - Injection Conversion
	[X] CONVERT WELL TYPE	[ ] RECOMPLETE - DIFFERENT FORMATION	

12. DESCRIBE PROPOSED OR COMPLETED OPERATIONS. Clearly show all pertinent details including dates, depths, volumes, etc.

The subject well was converted from a producing oil well to an injection well on 5/15/06. On 5/16/06 Dan Jackson with the EPA was contacted concerning the initial MIT on the above listed well. Permission was given at that time to perform the test on 5/17/06. On 5/17/06 the csg was pressured up to 1175 psig and charted for 30 minutes with no pressure loss. The well was not injecting during the test. The tbg pressure was 0 psig during the test. There was not an EPA representative available to witness the test. EPA # UT20994-06735 API #43-013-32505

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

NAME (PLEASE PRINT) Callie Duncan TITLE Production Clerk

SIGNATURE Callie Duncan DATE 05/22/2006

(This space for State use only)

RECEIVED
MAY 23 2006
DIV. OF OIL, GAS & MINING

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: 5 / 17 / 06
Test conducted by: J.D Horrocks
Others present: ______________________

Well Name: Black Jack 12-10-9-17 Type: ER SWD Status: AC TA UC
Field: Black Jack unit
Location: NW/NW Sec: 10 T 9 N/S R 17 E/W County: Duchesne State: ut
Operator: Newfield
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: 0 psig

MIT DATA TABLE	Test #1	Test #2	Test #3
TUBING	***PRESSURE***		
Initial Pressure	0 psig	psig	psig
End of test pressure	0 psig	psig	psig
CASING / TUBING	***ANNULUS***	***PRESSURE***	
0 minutes	1175 psig	psig	psig
5 minutes	1175 psig	psig	psig
10 minutes	1175 psig	psig	psig
15 minutes	1175 psig	psig	psig
20 minutes	1175 psig	psig	psig
25 minutes	1175 psig	psig	psig
30 minutes	1175 psig	psig	psig
______ minutes	psig	psig	psig
______ minutes	psig	psig	psig
RESULT	[X] Pass [ ] Fail	[ ] Pass [ ] Fail	[ ] Pass [ ] Fail

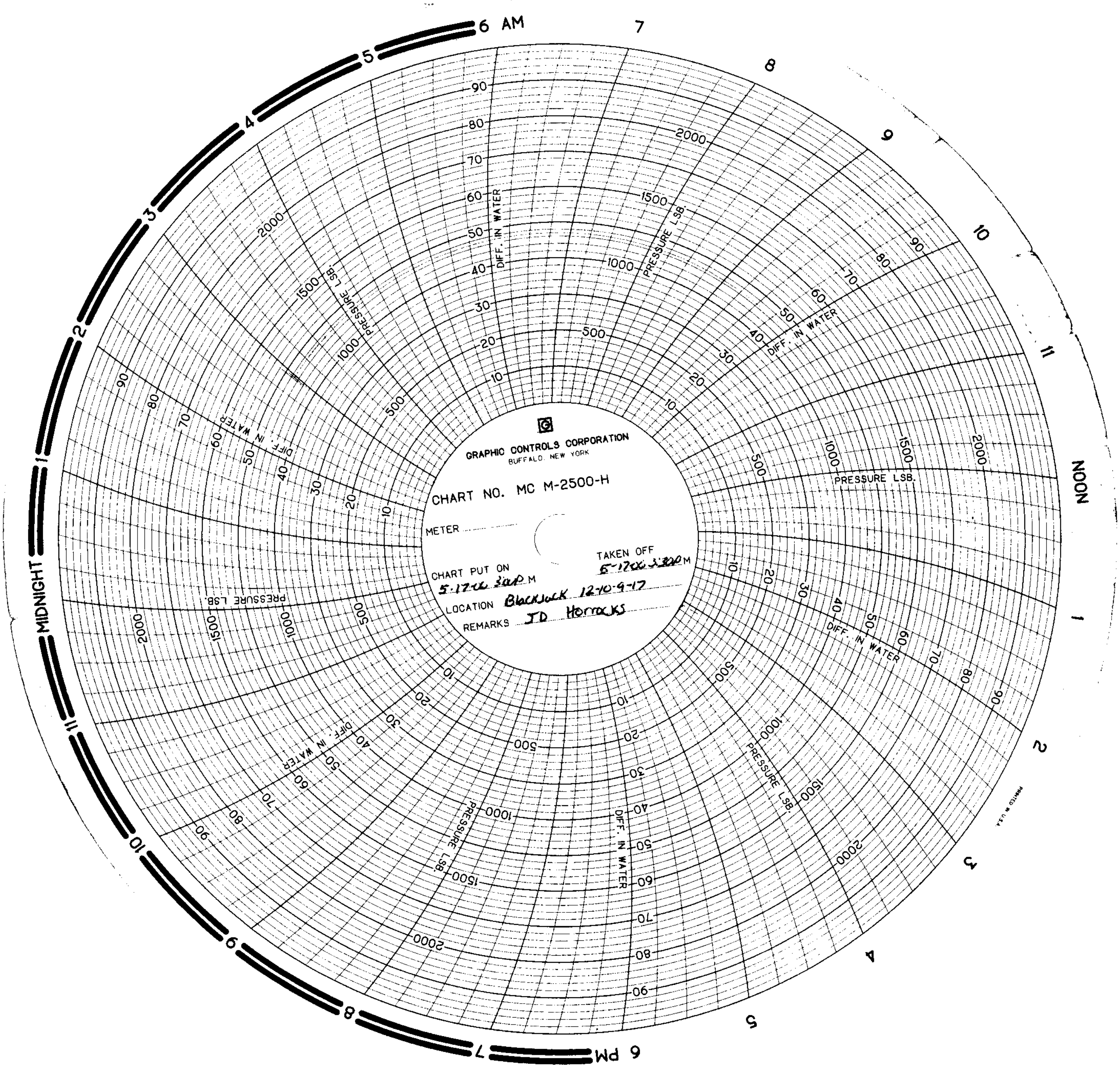
Does the annulus pressure build back up after the test ? [ ] Yes [X] No

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: ______________________


GRAPHIC CONTROLS CORPORATION
BUFFALO, NEW YORK
CHART NO. MC M-2500-H
METER
CHART PUT ON
5-17-cc 3:00P M
TAKEN OFF
5-17-cc 3:30P M
LOCATION Blackjack 12-10-9-17
REMARKS JD Horrocks
DIFF. IN WATER
PRESSURE LSB.
6 AM
7
8
9
10
11
NOON
1
2
3
4
5
6 PM
MIDNIGHT

4301332505
9S 17E 10

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 8
999 18TH STREET - SUITE 200
DENVER, CO 80202-2466
http://www.epa.gov/region08

JUN 15 2006

Ref: 8P-W-GW

CERTIFIED MAIL
RETURN RECEIPT REQUESTED

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

Mr. Mike Guinn
Vice President - Operations
Newfield Production Company
Route 3 - Box 3630
Myton, UT 84502

RE: **180-Day Limited Authorization to Inject**
Blackjack No. 12-10-9-17
EPA Permit No. UT20994-06735
Duchesne County, Utah

Dear Mr. Guinn:

The Newfield Production Company (Newfield) May 24, 2006 submission of **Prior to Commencing Injection** documents did contain all information required to fulfill the Environmental Protection Agency's (EPA) requirements, as cited in the Final Area Permit UT20994-06735. The submitted data included an EPA Well Rework Form (Form No. 7520-12), a Part I (Internal) Mechanical Integrity Test, and an injection zone pore pressure. All requirements were reviewed and approved by the EPA on May 31, 2006.

The EPA is hereby authorizing injection into the Blackjack No. 12-10-9-17 for a limited period of up to one hundred and eighty (180) calendar days, herein referred to as the "Limited Authorized Period". **The 180-Day "Limited Authorized Period" will commence upon the first date of enhanced recovery injection.** The permittee is responsible for notifying Emmett Schmitz, of my office, by letter within fifteen (15) working days of the date that enhanced recovery injection began. The initial maximum allowable injection pressure (MAIP) shall be **1385 psig**.

RECEIVED
JUN 19 2006
DIV OF OIL, GAS & MINING

Printed on Recycled Paper

Because the cement bond log submitted for this well did not show an adequate interval of 80% or greater bond index cement through the confining zone overlying the Garden Gulch Member, **the operator is required to demonstrate Part II (External) Mechanical Integrity (Part II MI) within the 180-day "Limited Authorized Period"**. Approved tests for demonstrating Part II (External) MI include a Temperature Survey, a Noise Log or Oxygen Activation Log, and Region 8 may also accept results of a Radioactive Tracer Survey under certain circumstances. The "Limited Authorized Period" allows injection for the purpose of stabilizing the injection formation pressure prior to demonstrating Part II (External) MI, which is necessary because the proposed injection zone is under-pressured due to previous oil production from the zone, and the tests rely on stable formation pressure. Results of tests shall be submitted to and written approval with authority to re-commence injection received from EPA prior to resuming injection following the "Limited Authorized Period". Copies of current Region 8 Guidelines for conducting Part II (External) Mechanical Integrity Tests will be submitted upon request.

Should you choose to apply for an increase to the MAIP, at any future date, **a demonstration of Part II (External) MI** must be conducted **in addition to the Step-Rate Test**. You must receive prior authorization from the Director in order to inject at pressures greater than the permitted MAIP during the test(s).

If you have any questions in regard to the above action, please contact Emmett Schmitz at 1-800-227-8917 (Ext. 6174), or 303-312-6174. Results from the Part II (External) MI Test, should be mailed directly to the **ATTENTION: EMMETT SCHMITZ**, at the letterhead address citing **MAIL CODE: 8P-W-GW** very prominently.

Sincerely,

Tracy M. Eagle

Tracy M. Eagle
Director
Ground Water Program

cc: David Gerbig
Operations Engineer
Newfield Production Company
Denver, CO 80202

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

Lynn Becker
Director
Energy & Minerals Department
Ute Indian Tribe

S. Elaine Willie
Environmental Director
Ute Indian Tribe

Chester Mills
Superintendent
Bureau of Indian Affairs
Uintah & Ouray Indian Agency

Gilbert Hunt
Technical Services Manager
State of Utah - Natural Resources
Division of Oil, Gas, and Mining

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

Mr. Nathan Wiser
8ENF-UFO

FORM 3160-5
(August 2007)

UNITED STATES
DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

FORM APPROVED
OMB No. 1004-0137
Expires: July 31,2010

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 page 2

5. Lease Serial No.
USA UTU-70821

6. If Indian, Allottee or Tribe Name.

7. If Unit or CA/Agreement, Name and/or
BLACKJACK UNIT

1. Type of Well
[X] Oil Well [ ] Gas Well [ ] Other

8. Well Name and No.
BLACKJACK FEDERAL 12-10-9-17

2. Name of Operator
NEWFIELD PRODUCTION COMPANY

9. API Well No.
4301332505

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

3b. Phone *(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)*
1999 FSL 730 FWL
NWSW Section 10 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			
[X] Notice of Intent	[ ] Acidize	[ ] Deepen	[ ] Production (Start/Resume)	[ ] Water Shut-Off
[ ] Subsequent Report	[ ] Alter Casing	[ ] Fracture Treat	[ ] Reclamation	[ ] Well Integrity
[ ] Final Abandonment	[ ] Casing Repair	[ ] New Construction	[ ] Recomplete	[X] Other Change status put well on injection.
	[ ] Change Plans	[ ] Plug & Abandon	[ ] Temporarily Abandon	
	[X] 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.)

The above reference well was put on injection at 1:30PM on 11-25-09.

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

I hereby certify that the foregoing is true and correct *(Printed/ Typed)*
Kathy Chapman

Title
Office Manager

Signature Kathy Chapman

Date
11/30/2009

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 page 2)

RECEIVED
DEC 02 2009
DIV. OF OIL, GAS & MINING

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 8
1595 Wynkoop Street
Denver, CO 80202-1129
Phone 800-227-8917
http://www.epa.gov/region08

OCT 14 2010

Ref: 8P-W-GW

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

CERTIFIED MAIL
RETURN RECEIPT REQUESTED

Mr. Michael Guinn
District Manager
Newfield Production Company
Route 3-Box 3630
Myton, UT 84502

RE: Underground Injection Control (UIC)
Authorization to Continue Injection
EPA UIC Permit UT20994-06735
Well: Blackjack Federal 12-10-9-17
NWSW Sec. 10-T9S-R17E
Duchesne County, UT
API No.: 43-013-32505

Dear Mr. Guinn:

The U.S. Environmental Protection Agency (EPA), Region 8, received the results of the February 1, 2010, Radioactive Tracer Survey (RTS) for the Blackjack Federal 12-10-9-17 well. EPA determined the test demonstrates the presence of adequate cement to prevent the upward migration of injection fluids from the injection zone at the Maximum Allowable Injection Pressure (MAIP) of 1,385 psig.

As of the date of this letter, EPA hereby authorizes continued injection into the Blackjack Federal 12-10-9-17 well under the terms and conditions of UIC Permit UT20994-06735.

You may apply for a higher MAIP at a later date. Your application should be accompanied by the interpreted results of a Step Rate Test (SRT) that measures the formation parting pressure and determines the fracture gradient at this depth and location. Newfield must receive prior authorization from the Director in order to inject at pressures greater than the permitted MAIP during any test. A current copy of EPA guidelines for running and interpreting SRTs will be sent upon request. Should the SRT result in approval of a higher MAIP, a subsequent RTS conducted at the higher MAIP is required.

RECEIVED
OCT 21 2010
DIV. OF OIL, GAS & MINING

As of this approval, responsibility for permit compliance and enforcement is transferred to EPA's UIC Technical Enforcement Program. Therefore, please direct all monitoring and compliance correspondence to Nathan Wiser at the following address, referencing the well name and UIC Permit number on all correspondence:

Mr. Nathan Wiser
U.S. EPA Region 8: 8ENF-UFO
1595 Wynkoop Street
Denver, CO 80202-1129

Or, you may reach Mr. Wiser by telephone at 303-312-6211, or 1 800-227-8927, ext. 312-6211. Please remember that it is your responsibility to be aware of and to comply with all conditions of injection well Permit UT20994-06735.

If you have questions regarding the above action, please call Jason Deardorff at 303-312-6583 or 1-800-227-8917, ext. 312-6583.

Sincerely,

Steven T Pratt

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

cc: Uintah & Ouray Business Committee:
Frances Poowegup, Vice-Chairwoman
Curtis Cesspooch, Councilman
Phillip Chimburas, Councilman
Stewart Pike, Councilman
Irene Cuch, Councilwoman
Richard Jenks, Jr., Councilman

Daniel Picard
BIA - Uintah & Ouray Indian Agency

Mike Natchees
Environmental Coordinator
Ute Indian Tribe

Manual Myore
Director of Energy & Minerals Dept.
Ute Indian Tribe

Brad Hill
Acting Associate Director
Utah Division of Oil, Gas, and Mining

Fluid Minerals Engineering Office
BLM - Vernal Office

Eric Sundberg
Regulatory Analyst
Newfield Production Company

STATE OF UTAH
DEPARTMENT OF NATURAL RESOURCES
DIVISION OF OIL, GAS AND MINING

5. LEASE DESIGNATION AND SERIAL NUMBER: USA UTU-70821

6. IF INDIAN, ALLOTTEE OR TRIBE NAME:

7. UNIT or CA AGREEMENT NAME: GMBU

8. WELL NAME and NUMBER: BLACKJACK FEDERAL 12-10-9-17

9. API NUMBER: 4301332505

10. FIELD AND POOL, OR WILDCAT: GREATER MB UNIT

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.

1. TYPE OF WELL: OIL WELL [X] GAS WELL [ ] OTHER

2. NAME OF OPERATOR: NEWFIELD PRODUCTION COMPANY

3. ADDRESS OF OPERATOR: Route 3 Box 3630 CITY Myton STATE UT ZIP 84052 PHONE NUMBER 435.646.3721

4. LOCATION OF WELL:
FOOTAGES AT SURFACE: 1999 FSL 730 FWL
COUNTY: DUCHESNE
OTR/OTR. SECTION. TOWNSHIP. RANGE. MERIDIAN: NWSW, 10, T9S, R17E
STATE: UT

11. CHECK APPROPRIATE BOXES TO INDICATE NATURE OF NOTICE, REPORT, OR OTHER DATA

TYPE OF SUBMISSION	TYPE OF ACTION		
[ ] NOTICE OF INTENT (Submit in Duplicate)	[ ] ACIDIZE	[ ] DEEPEN	[ ] REPERFORATE CURRENT FORMATION
Approximate date work will	[ ] ALTER CASING	[ ] FRACTURE TREAT	[ ] SIDETRACK TO REPAIR WELL
	[ ] CASING REPAIR	[ ] NEW CONSTRUCTION	[ ] TEMPORARITLY ABANDON
	[ ] CHANGE TO PREVIOUS PLANS	[ ] OPERATOR CHANGE	[ ] TUBING REPAIR
	[ ] CHANGE TUBING	[ ] PLUG AND ABANDON	[ ] VENT OR FLAIR
[X] SUBSEOUENT REPORT (Submit Original Form Only)	[ ] CHANGE WELL NAME	[ ] PLUG BACK	[ ] WATER DISPOSAL
Date of Work Completion:	[ ] CHANGE WELL STATUS	[ ] PRODUCTION (START/STOP)	[ ] WATER SHUT-OFF
	[ ] COMMINGLE PRODUCING FORMATIONS	[ ] RECLAMATION OF WELL SITE	[X] OTHER: - Five Year MIT
04/18/2011	[ ] CONVERT WELL TYPE	[ ] RECOMPLETE - DIFFERENT FORMATION	

12. DESCRIBE PROPOSED OR COMPLETED OPERATIONS. Clearly show all pertinent details including dates, depths, volumes, etc.

On 04/04/2011 Nathan Wiser with the EPA was contacted concerning the 5 year MIT on the above listed well. On 04/18/2011 the casing was pressured up to 1050 psig and charted for 30 minutes with no pressure loss. The well was not injecting during the test. The tubing pressure was 1321 psig during the test. There was not an EPA representative available to witness the test.

EPA# UT20994-06735 API# 43-013-32505

Accepted by the Utah Division of Oil, Gas and Mining

FOR RECORD ONLY

NAME (PLEASE PRINT) Lucy Chavez-Naupoto TITLE Water Services Technician

SIGNATURE Lucy Chavez-Naupoto DATE 04/19/2011

(This space for State use only)

RECEIVED
APR 25 2011
DIV. OF OIL, GAS & MINING

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: 04 / 18 / 11

Test conducted by: Dale Giles

Others present: ______________________

Well Name: Blackjack 12-10-9-17 Type: ER SWD Status: AC TA UC
Field: Monument Butte
Location: NW/NW Sec: 10 T 9 N/(S) R 17 (E)/W County: Duchesne State: UT
Operator: Newfield Production Co.
Last MIT: ___/___/___ Maximum Allowable Pressure: 1385 PSIG

Is this a regularly scheduled test? [X] Yes [ ] No
Initial test for permit? [ ] Yes [X] No
Test after well rework? [ ] Yes [X] No
Well injecting during test?[1] [X] Yes [ ] No If Yes, rate: 43 bpd

Pre-test casing/tubing annulus pressure: 0 psig

MIT DATA TABLE	Test #1	Test #2	Test #3
TUBING	*PRESSURE*		
Initial Pressure	1321 psig	psig	psig
End of test pressure	1321 psig	psig	psig
CASING / TUBING	*ANNULUS*	*PRESSURE*	
0 minutes	1050 psig	psig	psig
5 minutes	1050 psig	psig	psig
10 minutes	1050 psig	psig	psig
15 minutes	1050 psig	psig	psig
20 minutes	1050 psig	psig	psig
25 minutes	1050 psig	psig	psig
30 minutes	1050 psig	psig	psig
______ minutes	psig	psig	psig
______ minutes	psig	psig	psig
RESULT	[X] Pass [ ] Fail	[ ] Pass [ ] Fail	[ ] Pass [ ] Fail

Does the annulus pressure build back up after the test ? [ ] Yes [X] 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.:

____

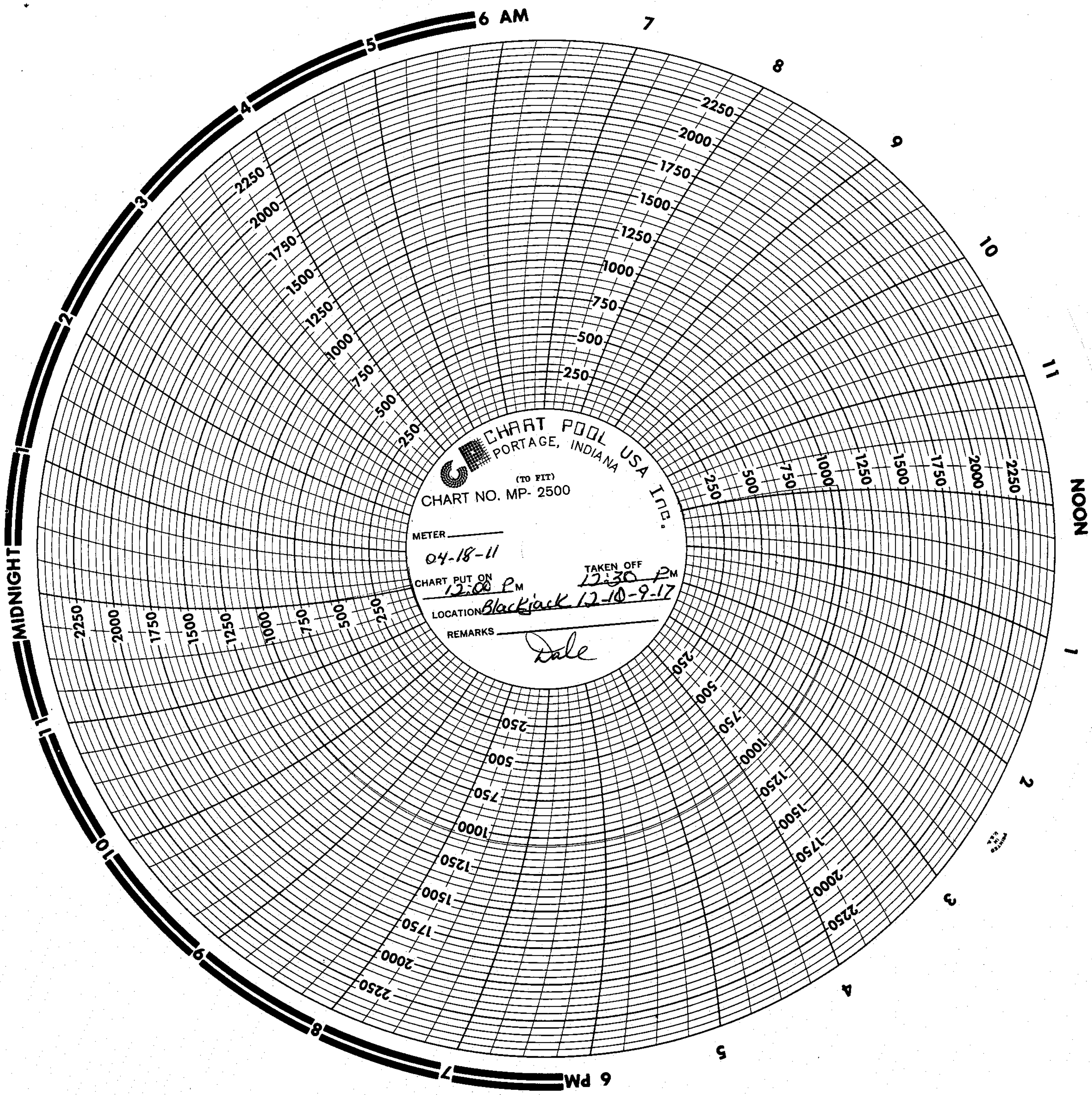


CHART POOL USA Inc.
PORTAGE, INDIANA
(TO FIT)
CHART NO. MP- 2500
METER
04-18-11
CHART PUT ON 12:00 PM
TAKEN OFF 12:30 PM
LOCATION Blackjack 12-10-9-17
REMARKS
Dale
6 AM
7
8
9
10
11
NOON
1
2
3
4
5
6 PM
MIDNIGHT
250
500
750
1000
1250
1500
1750
2000
2250

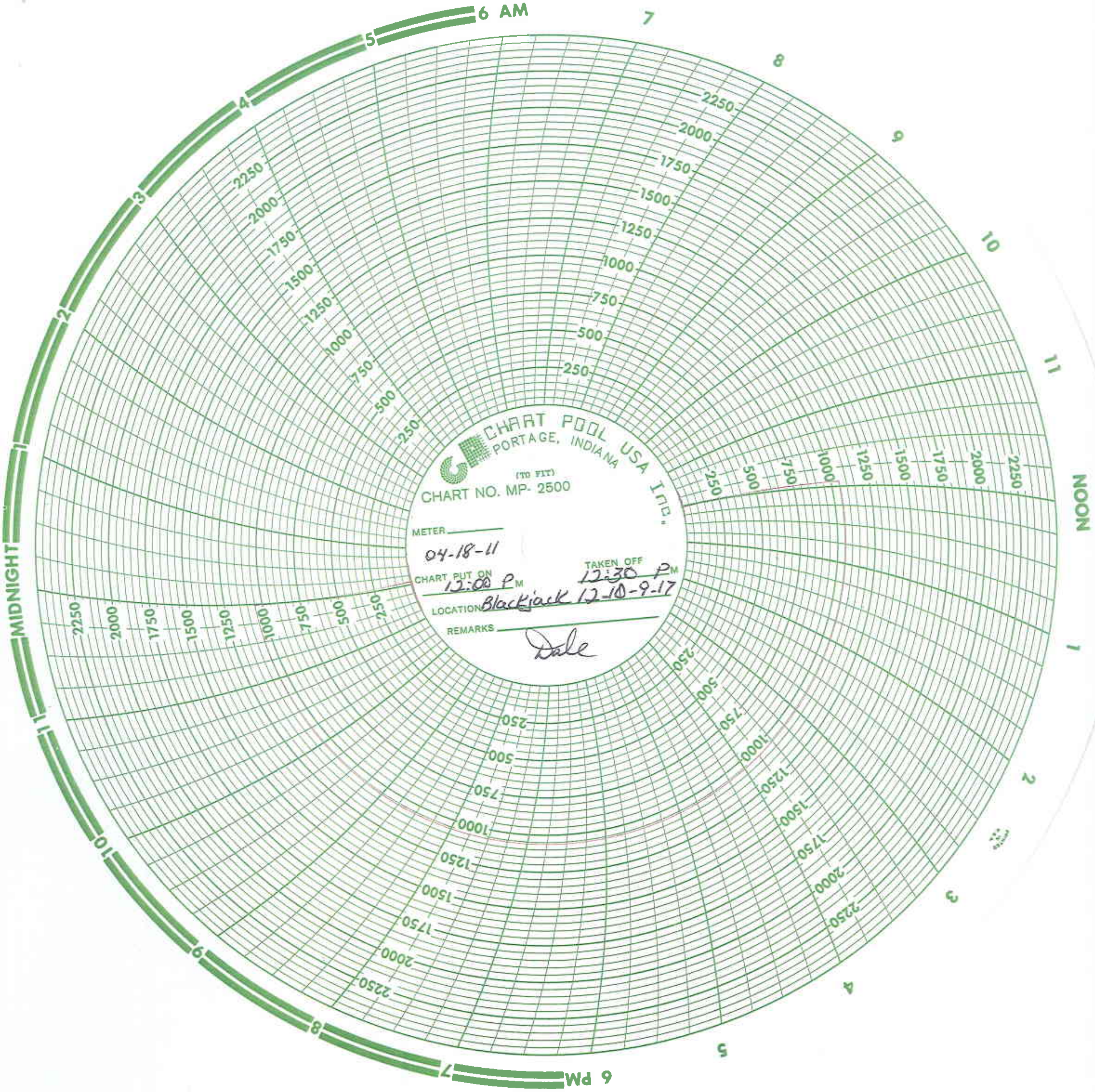


CHART POOL USA Inc.
PORTAGE, INDIANA
(TO FIT)
CHART NO. MP- 2500
METER
04-18-11
CHART PUT ON 12:00 PM
TAKEN OFF 12:30 PM
LOCATION Blackjack 12-10-9-17
REMARKS
Dale
6 AM
NOON
6 PM
MIDNIGHT
250
500
750
1000
1250
1500
1750
2000
2250

FORM 9

STATE OF UTAH
DEPARTMENT OF NATURAL RESOURCES
DIVISION OF OIL, GAS, AND MINING

5.LEASE DESIGNATION AND SERIAL NUMBER: UTU-70821

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 12-10-9-17

2. NAME OF OPERATOR: NEWFIELD PRODUCTION COMPANY

9. API NUMBER: 43013325050000

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: 1999 FSL 0730 FWL
QTR/QTR, SECTION, TOWNSHIP, RANGE, MERIDIAN: Qtr/Qtr: NWSW Section: 10 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

- ☐ NOTICE OF INTENT — Approximate date work will start:
- ✓ SUBSEQUENT REPORT — Date of Work Completion: 11/16/2012
- ☐ SPUD REPORT — Date of Spud:
- ☐ DRILLING REPORT — Report Date:

TYPE OF ACTION

☐ ACIDIZE	☐ ALTER CASING	☐ CASING REPAIR
☐ CHANGE TO PREVIOUS PLANS	☐ CHANGE TUBING	☐ CHANGE WELL NAME
☐ CHANGE WELL STATUS	☐ COMMINGLE PRODUCING FORMATIONS	☐ CONVERT WELL TYPE
☐ DEEPEN	☐ FRACTURE TREAT	☐ NEW CONSTRUCTION
☐ OPERATOR CHANGE	☐ PLUG AND ABANDON	☐ PLUG BACK
☐ 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: Workover MIT

12. DESCRIBE PROPOSED OR COMPLETED OPERATIONS. Clearly show all pertinent details including dates, depths, volumes, etc.

The above subject well had workover procedures performed (tubing leak), attached is a daily status report. On 10/31/2012 Nathan Wiser with the EPA was contacted concerning the MIT on the above listed well. On 11/16/2012 the csg was pressured up to 1050 psig and charted for 30 minutes with no pressure loss. The well was not injecting during the test. The tbg pressure was 800 psig during the test. There was not an EPA representative available to witness the test. EPA #UT20994-06735

Accepted by the Utah Division of Oil, Gas and Mining
FOR RECORD ONLY
November 26, 2012

NAME (PLEASE PRINT) Lucy Chavez-Naupoto

PHONE NUMBER 435 646-4874

TITLE Water Services Technician

SIGNATURE N/A

DATE 11/20/2012

RECEIVED: Nov. 20, 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: 11 / 16 / 2012
Test conducted by: Brendan Curry
Others present: ____________________

UT 20994-06735

Well Name: Black Jack Fed 12-10-9-17 Type: ER SWD Status: AC TA UC
Field: Greater Monument Butte
Location: 12 Sec: 10 T 9 N / S R 17 E / W County: Duchesne State: UT
Operator: ____________________
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: __________ psig

MIT DATA TABLE	Test #1	Test #2	Test #3
TUBING	***PRESSURE***		
Initial Pressure	800 psig	psig	psig
End of test pressure	800 psig	psig	psig
CASING / TUBING	***ANNULUS***	***PRESSURE***	
0 minutes	1050 psig	psig	psig
5 minutes	1050 psig	psig	psig
10 minutes	1050 psig	psig	psig
15 minutes	1050 psig	psig	psig
20 minutes	1050 psig	psig	psig
25 minutes	1050 psig	psig	psig
30 minutes	1050 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

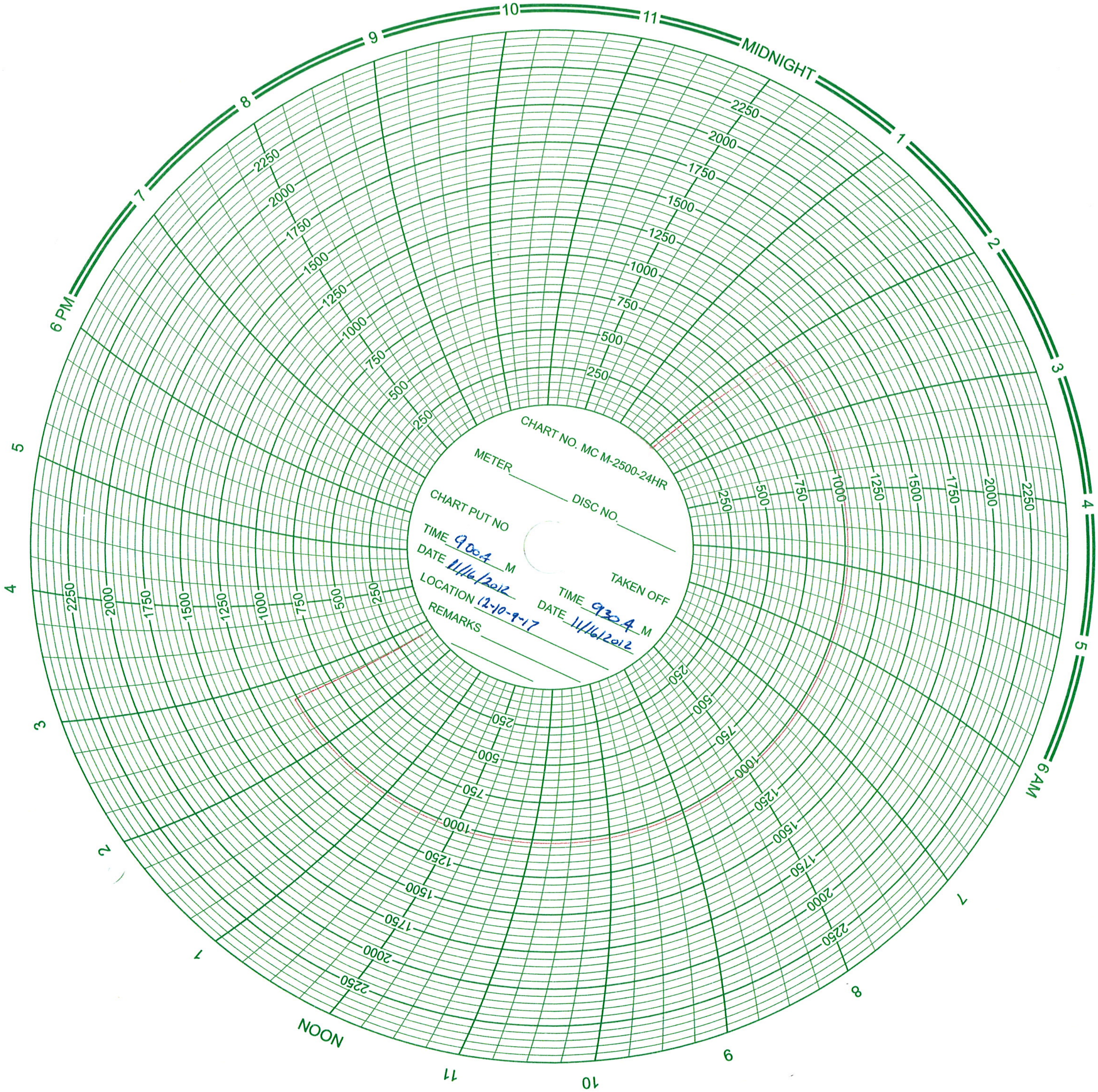
MECHANICAL INTEGRITY PRESSURE TEST

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: ____________________

Sundry Number: 32222 API Well Number: 43013325050000



Daily Activity Report

Format For Sundry

BLACKJACK 12-10-9-17

9/1/2012 To 1/30/2013

10/18/2012 Day: 1 **Well Stimulation**

Rigless on 10/18/2012 - Perform acid jobs and resume injection - MIRU acid truck, hot oiler and flow back tank. Perform specific acid procedure using preferred hot oil and weatherford. Pump acid down hole to stimulate perfs at certain depth. Flow back well and return injection. - MIRU acid truck, hot oiler and flow back tank. Perform specific acid procedure using preferred hot oil and weatherford. Pump acid down hole to stimulate perfs at certain depth. Flow back well and return injection. - MIRU acid truck, hot oiler and flow back tank. Perform specific acid procedure using preferred hot oil and weatherford. Pump acid down hole to stimulate perfs at certain depth. Flow back well and return injection. **Finalized**
Daily Cost: $0
Cumulative Cost: $11,958

11/13/2012 Day: 1 **Workover**

WWS #9 on 11/13/2012 - Flow back and RU - Rig up wait on flowback TNK and PIT 1:00 open CSG up flowback 60 bble ND WH PW TBG release PKR, NU BOPs Flush TBG W, 40 bble @ 250f DROP SV Circulate Down to PSN w, 20 bbls pressure up 3000 psi CK in morning. - Rig up wait on flowback TNK and PIT 1:00 open CSG up flowback 60 bble ND WH PW TBG release PKR, NU BOPs Flush TBG W, 40 bble @ 250f DROP SV Circulate Down to PSN w, 20 bbls pressure up 3000 psi CK in morning. - Rig up wait on flowback TNK and PIT 1:00 open CSG up flowback 60 bble ND WH PW TBG release PKR, NU BOPs Flush TBG W, 40 bble @ 250f DROP SV Circulate Down to PSN w, 20 bbls pressure up 3000 psi CK in morning.
Daily Cost: $0
Cumulative Cost: $12,730

11/14/2012 Day: 2 **Workover**

WWS #9 on 11/14/2012 - CR press TBG 2700 PSI lost 300 psi over night RIH retreive sv sandline TOOH w/40 - CR press on TBG 2700 PSI lost 300 psi over night RIH retrieve SV POOH sv sandline TOOH w/ 40 jts started swabbing back oil out of csg shut down 900am wait on hot oiler 945am circulate 60 bbl down tbg 250" coat TOOH 102 jts LD pkr mark up new BHA TIH w/ 2-3/8 re-entry guide, 2-3/8X1.87 XN/ nipple 1.4x2-3/8 sab, 2-3/8 psn 142 jts 2-3/8 j-55 tbs prop sv press up to 3000 psi watch for the no lose beed off press - - - CR press on TBG 2700 PSI lost 300 psi over night RIH retrieve SV POOH sv sandline TOOH w/ 40 jts started swabbing back oil out of csg shut down 900am wait on hot oiler 945am circulate 60 bbl down tbg 250" coat TOOH 102 jts LD pkr mark up new BHA TIH w/ 2-3/8 re-entry guide, 2-3/8X1.87 XN/ nipple 1.4x2-3/8 sab, 2-3/8 psn 142 jts 2-3/8 j-55 tbs prop sv press up to 3000 psi watch for the no lose beed off press - - CR press on TBG 2700 PSI lost 300 psi over night RIH retrieve SV POOH sv sandline TOOH w/ 40 jts started swabbing back oil out of csg shut down 900am wait on hot oiler 945am circulate 60 bbl down tbg 250" coat TOOH 102 jts LD pkr mark up new BHA TIH w/ 2-3/8 re-entry guide, 2-3/8X1.87 XN/ nipple 1.4x2-3/8 sab, 2-3/8 psn 142 jts 2-3/8 j-55 tbs prop sv press up to 3000 psi watch for the no lose beed off press **Finalized**
Daily Cost: $0
Cumulative Cost: $18,435

11/15/2012 Day: 3 **Workover**

WWS #9 on 11/15/2012 - Thow WH RTH w, sandline retieve sv pooh rd floor and tbg works ND BOPS. RD reaady for mit - Thow WH RTH w, sandline retieve sv pooh rd floor and tbg works ND BOPS 4 bolt well head pump 60 bbl pkr fluid roam csg pu set 5-1/2 arrow set pkr w, ce@ 4637' w/ 13000 tention on mipple up WH press up CSG to 1500 psi watch for 30 min good SWJ Rig powermove off - Thow WH RTH w, sandline retieve sv pooh rd floor and tbg works ND BOPS 4 bolt well head pump 60 bbl pkr fluid roam csg pu set 5-1/2 arrow set pkr w, ce@ 4637' w/ 13000 tention on mipple up WH press up CSG to 1500 psi watch for 30 min good SWJ Rig powermove off - Thow WH RTH w, sandline retieve sv pooh rd floor and tbg works ND BOPS 4 bolt well head pump 60 bbl pkr fluid roam csg pu set 5-1/2 arrow set pkr w, ce@ 4637' w/ 13000 tention on mipple up WH press up CSG to 1500 psi watch for 30 min good SWJ Rig powermove off **Finalized**
Daily Cost: $0
Cumulative Cost: $21,414

11/19/2012 Day: 4 **Workover**

Rigless on 11/19/2012 - Conduct MIT - On 10/31/2012 Sarah Roberts with the EPA was contacted concerning the MIT on the above listed well. On 11/16/2012 the csg was pressured up to 1050 psig and charted for 30 minutes with no pressure loss. The well was not injecting during the test. The tbg pressure was 800 psig during the test. There was not an EPA representative available to witness the test. EPA #UT20994-06735 - On 10/31/2012 Sarah Roberts with the EPA was contacted concerning the MIT on the above listed well. On 11/16/2012 the csg was pressured up to 1050 psig and charted for 30 minutes with no pressure loss. The well was not injecting during the test. The tbg pressure was 800 psig during the test. There was not an EPA representative available to witness the test. EPA #UT20994-06735 - On 10/31/2012 Sarah Roberts with the EPA was contacted concerning the MIT on the above listed well. On 11/16/2012 the csg was pressured up to 1050 psig and charted for 30 minutes with no pressure loss. The well was not injecting during the test. The tbg pressure was 800 psig during the test. There was not an EPA representative available to witness the test. EPA #UT20994-06735 **Finalized**
Daily Cost: $0
Cumulative Cost: $22,314

Pertinent Files: Go to File List

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 8
1595 Wynkoop Street
DENVER, CO 80202-1129
Phone 800-227-8917
http://www.epa.gov/region08

DEC 04 2012

Ref: 8ENF-UFO

RECEIVED
DEC 07 2012
DIV. OF OIL, GAS & MINING

CERTIFIED MAIL 7009-3410-0000-2599-7532
RETURN RECEIPT REQUESTED

Mr. J D Horrocks
Newfield Exploration Company
Route 3, Box 3630
Myton, UT 84052

Re: Underground Injection Control (UIC)
Permission to Resume Injection
Blackjack Federal 12-10-9-17 Well
EPA ID# UT20994-06735
API # 43-013-32505 9S 17E 10
Monument Butte Oil Field
Duchesne County, UT

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

Dear Mr. Horrocks:

On November 26, 2012, the Environmental Protection Agency (EPA) received information from Newfield Exploration Company on the above referenced well concerning the workover to address a tubing leak and the followup mechanical integrity test (MIT) conducted on November 16, 2012. The data submitted shows that the well passed the required MIT. Therefore, pursuant to Title 40 of the Code of Federal Regulations Section 144.51(q)(2) (40 C.F.R. §144.51(q)(2)), permission to resume injection is granted. Under continuous service, the next MIT will be due on or before November 16, 2017.

Pursuant to 40 C.F.R. §144.52(a)(6), if the well is not used for a period of at least two (2) years ("temporary abandonment"), it shall be plugged and abandoned unless EPA is notified and procedures are described to EPA ensuring the well will not endanger underground sources of drinking water ("non-endangerment demonstration") during its continued temporary abandonment. A successful MIT is an acceptable non-endangerment demonstration and would be necessary every two (2) years the well continues in temporary abandonment.

Failure to comply with a UIC Permit, or the UIC regulations found at 40 C.F.R. Parts 144 through 148 constitute one or more violations of the Safe Drinking Water Act, 42 U.S.C. §300h. Such non-compliance may subject you to formal enforcement by EPA, as codified at 40 C.F.R. Part 22.

If you have any questions concerning this letter, you may contact Sarah Roberts at (303) 312-7056. Please direct all correspondence to the attention of Sarah Roberts at Mail Code 8ENF-UFO.

Sincerely,

Darcy O'Connor, Acting Director
UIC/FIFRA/OPA Technical Enforcement Programs

cc:

Irene Cuch, Jr., Chairwoman
Uintah & Ouray Business Committee
P.O. Box 190
Fort Duchesne, Utah 84026

Reannin Tapoof, Assistant
Uintah & Ouray Business Committee
P.O. Box 190
Fort Duchesne, Utah 84026

Richard Jenks, Councilman
Uintah & Ouray Business Committee
P.O. Box 190
Fort Duchesne, Utah 84026

Phillip Chimburas, Councilman
Uintah & Ouray Business Committee
P.O. Box 190
Fort Duchesne, Utah 84026

Mike Natchees, Environmental Coordinator
Ute Indian Tribe
P.O. Box 190
Fort Duchesne, Utah 84026

Ronald Wopsock, Vice-Chairman
Uintah & Ouray Business Committee
P.O. Box 190
Fort Duchesne, Utah 84026

Stewart Pike, Councilman
Uintah & Ouray Business Committee
P.O. Box 190
Fort Duchesne, Utah 84026

Frances Poowegup, Councilwoman
Uintah & Ouray Business Committee
P.O. Box 190
Fort Duchesne, Utah 84026

Manuel Myore, Director of Energy, Minerals and Air Programs
Ute Indian Tribe
P.O. Box 190
Fort Duchesne, Utah 84026

John Rogers
Utah Division of Oil, Gas and Mining
P.O. Box 145801
Salt Lake City, Utah 84114

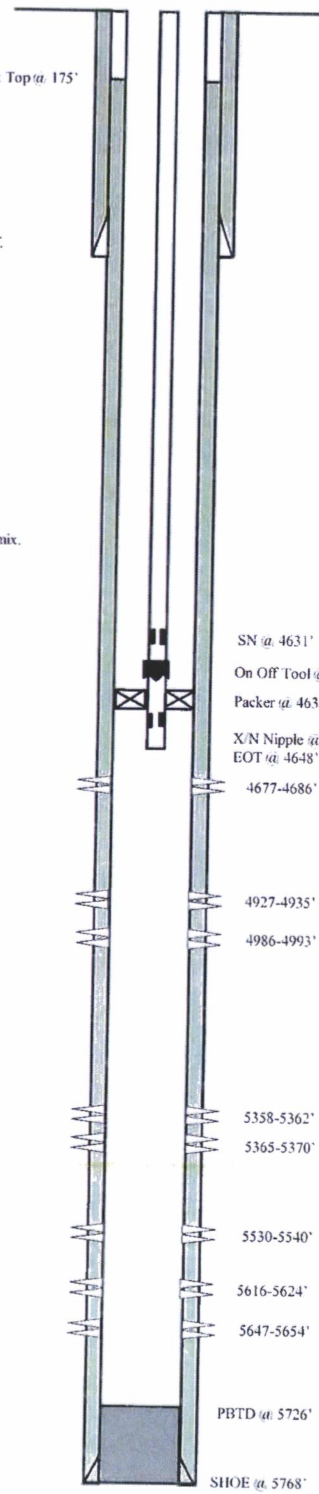
Blackjack Federal 12-10-9-17

Spud Date: 7/17/2004

Put on Production: 8/16/2004

GL: 5172' KB: 5184'

Injection Wellbore Diagram



SURFACE CASING

CSG SIZE: 8 5/8"

GRADE: J-55

WEIGHT: 24#

LENGTH: 7 jts. (299.28')

DEPTH LANDED: 309.28' KB

HOLE SIZE: 12 1/4"

CEMENT DATA: 150 sxs Class "G" mixed cmt, est 4 bbls cmt to surf.

PRODUCTION CASING

CSG SIZE: 5 1/2"

GRADE: J-55

WEIGHT: 15.5#

LENGTH: 134 jts. (5770.23')

DEPTH LANDED: 5768.23' KB

HOLE SIZE: 7 7/8"

CEMENT DATA: 325 sxs Prem. Lite II mixed & 425 sxs 50/50 POZ mix.

CEMENT TOP AT: 175'

TUBING

SIZE/GRADE/WT.: 2 7/8" / J-55 / 6.5#

NO. OF JOINTS: 142 jts (4619.5')

SEATING NIPPLE: 2-7/8" (1.10')

SN LANDED AT: 4631.5' KB

ON/OFF TOOL AT: 4632.6'

ARROW #1 PACKER CE AT: 4637.74'

XO 2-3/8 x 2-7/8 J-55 AT: 4641.6'

TBG PUP 2-3/8 J-55 AT: 4642.1'

X/N NIPPLE AT: 4646.3'

TOTAL STRING LENGTH: EOT @ 4648'

FRAC JOB

08/10/04	5530-5654'	**Frac CP5 and 4 sands as follows:** 39,909# 20/40 sand in 382 bbls Lightning 17 frac fluid. Treated @ avg press of 1521 psi w/avg rate of 24.7 BPM. ISIP 1850 psi. Calc flush: 5528 gal. Actual flush: 5527 gal.
08/10/04	5358-5370'	**Frac CP1 sands as follows:** 37,686# 20/40 sand in 357 bbls Lightning 17 frac fluid. Treated @ avg press of 1346 psi w/avg rate of 24.8 BPM. ISIP 1600 psi. Calc flush: 5356 gal. Actual flush: 5355 gal.
08/10/04	4927-4993'	**Frac A1 and A3 sands as follows:** 33,275# 20/40 sand in 335 bbls Lightning 17 frac fluid. Treated @ avg press of 1711 psi w/avg rate of 24.7 BPM. ISIP 2000 psi. Calc flush: 4925 gal. Actual flush: 4914 gal.
08/10/04	4677-4686'	**Frac C sands as follows:** 15,212# 20/40 sand in 220 bbls Lightning 17 frac fluid. Treated @ avg press of 2012 psi w/avg rate of 24.6 BPM. ISIP 2230 psi. Calc flush: 4675 gal. Actual flush: 4591 gal.
5/15/06		**Well converted to an Injection well.**
5/22/06		**MIT completed and submitted.**
11/16/12		**Workover Tbg Leak – MIT finalized –** update tbg detail

PERFORATION RECORD

8/06/04	5647-5654'	4 JSPF	28 holes
8/06/04	5616-5624'	4 JSPF	32 holes
8/06/04	5530-5540'	4 JSPF	40 holes
8/10/04	5365-5370'	4 JSPF	20 holes
8/10/04	5358-5362'	4 JSPF	16 holes
8/10/04	4986-4993'	4 JSPF	28 holes
8/10/04	4927-4935'	4 JSPF	32 holes
8/10/04	4677-4686'	4 JSPF	36 holes

NEWFIELD

Blackjack Federal 12-10-9-17

1999' FSL & 730' FWL

NW/SW Section 10-T9S-R17E

Duchesne Co. Utah

API #43-013-32505; Lease #UTU-70821

LCN 11/19/12